UNITED STATES OF AMERICA

NATIONAL TRANSPORTATION SAFETY BOARD

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Investigation of: *
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ENBRIDGE - LINE 6B RUPTURE IN * Docket No.: DCA-10-MP-007
MARSHALL, MICHIGAN *
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Interview of: STEPHEN IRVING

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
[redacted]

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 number 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, Steve, please state your full name, with spelling, employer name, and job title.

MR. IRVING: Okay. Thank you. My name is Stephen Irving, S-t-e-p-h-e-n, I-r-v-i-n-g. My job title presently is director, pipeline compliance and risk management. At the time of the Marshall incident my title was director, system integrity and compliance.

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

MR. IRVING: My contact phone number at work is [redacted] and my e-mail address is [redacted].

MR. NICHOLSON: Okay. Thanks. Steve, 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. IRVING: Jay Johnson I have chosen to be present.

MR. NICHOLSON: Okay. Jay is technically the party rep so you are allowed to have one additional person if you'd like just --

MR. IRVING: Oh. I have chosen not to have anybody.

MR. NICHOLSON: Okay. All right. We'll go around the room and introduce ourselves. I'll start and we'll go clockwise from there.

Matthew Nicholson, M-a-t-t-h-e-w, N-i-c-h-o-l-s-o-n. I'm with the NTSB as the IIC on this case. My number is [redacted]. My e-mail is [redacted].

MR. FOX: Matt Fox, M-a-t-t, F-o-x. Phone number is [redacted]. E-mail [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 with the [redacted] and my e-mail is [redacted]

MR. CHHATRE: Ravi Chhatre, NTSB. I am Integrity Management Group chair. My telephone number is [redacted]. E-mail: ravindra.chhatre -- [redacted].

INTERVIEW OF STEPHEN IRVING

BY MR. NICHOLSON:

Q. So Steve, to begin with since we don't have a whole lot of information on your role here, if you could maybe start with your background, positions you've held at Enbridge and just work your way up from when you started, maybe, until now?

A. Okay. I have about 35 years experience in the oil and gas business. I joined Enbridge in 1992 and my role back then was the general superintendent for the gathering systems, which is headquartered out of -- from an operational perspective out of Estevan, Saskatchewan. We have a gathering system in Enbridge that covers about 2500 miles of small-inch diameter pipe that delivers crude out of southeast Saskatchewan primarily to the Enbridge main line terminal at Cromer, Manitoba. I was there from 1992 to 1998.

At that point in time I -- actually, in the middle of that period of time, in 1995, Producers Pipelines, as it was known back then, was taken over by Enbridge in March of 1995. We became part of the Enbridge Family at that point in time and we were rolled into the Enbridge group of companies, which back then was known as IPO Energy, Inc.

In 1998, I was transferred from Estevan to Edmonton and became general manager of the Western Region in operations. Western Region, at that point in time comprised the main line system starting at Milepost 0, which was the Edmonton Terminal, and went as far as Milepost 333, which was the suction piping to the Loreburn Station in Saskatchewan. I had about 100, 110 people reporting to me in an operational sense that included pipeline maintenance, electricians, mechanics, terminal gaugers and such. During my time as general manager, which lasted until December 31st, 2003, we also took over the operation of our Athabasca Pipeline, which is -- which was our core asset at the time for delivering oil sands crude to our main line in Hardisty and I put a team of about 20 people in Fort McMurray to operate our assets there.

At the end of 2003 I became director of pipeline operations and moved into the tower here in Edmonton from the operational group out in Sherwood Park at the terminal, and the title or the -- I guess, the job description that I had then I had a number of different groups that reported to me, which included the control center here in Edmonton. I had the petroleum quality group, the petroleum measurement group, lands and right-of-way, operational risk management and compliance. That job, though, was -- it disappeared in the sense that we reorganized part way through 2004 and that job was broken up into, you could say, and reported to different groups.

At that point in time, on July 1st, 2004, I became the director of system integrity and compliance. That included the pipeline integrity group, our operational risk management and facilities integrity as a separate department, and then the third department was pipeline compliance, which included both U.S. and Canadian staff. And I held that position until November 30th of

2010.

Starting December 1st in 2010, I assumed my present responsibilities, and that includes the pipeline compliance groups both in the U.S. and Canada and operational risk management located here in Edmonton, as well.

Q. Okay. So basically, they split off the integrity portion of your work?

A. That's correct.

Q. Okay. Can you go back and just -- I didn't catch, what was your educational background?

A. Oh. I'm a mechanical engineer. I graduated in 1976 from Queens University in mechanical engineering and have been in the oil and gas business since graduation. The first 16 -- approximately 16 years of my career were spent in the upstream industry with Dome Petroleum and AMOCO Petroleum Company in Canada and I had various engineering, field operations, oil and gas exploitation functions in that time.

Q. When you were talking about your background, you mentioned a reorganization in 2004. Can you explain why the company reorganized? What was going on in 2004?

A. 2004, the group that I had -- and primarily this would have been oil quality and the control center, they decided to consolidate those operations under shipper services, or I should say, with shipper services because we had entered into at that point an agreement with CAPP -- again, that's the Canadian

Association of Petroleum Producers -- into an incentive tolling agreement and we were incented, for instance, to maintain and improve quality of crude oil that we were -- that was delivered to our system. So they wanted to put all the groups that affected quality -- for instance, such as the control center because they ran the pipelines and they were the ones that made the determinations, for instance, on batch cuts between different crude types, so they put that group with petroleum quality and the shipper services together and they ended up reporting to another VP at that time.

Q. Who was that VP? Do you know?

A. I believe at that time -- it's going to be subject to check, but it may have been Sonya Buys.

Q. Okay. So it was driven by that CAPP agreement?

A. Partially, yes.

Q. Okay. Okay. So can you describe in a little more detail, then, going back to 2010 before the recent change, some of your responsibilities as -- you had oversight, I guess, of the compliance, risk management and integrity management?

A. Correct.

Q. Can you discuss a little further those responsibilities? Who reported to you; who did you report to?

A. Okay. I reported to John Gerez, who was the VP of engineering and system integrity at that time. I had responsibility for the integrity groups, both pipeline integrity and facilities integrity. At that time we had two principal managers in the pipeline integrity group that was divided between materials and analysis -- and Scott Ironside, who was here earlier today, was the manager of that group -- and then the other group was programs and technical services. And at the time of the Marshall incident, actually, we were transitioning Tom Zimmerman from that role into a program manager role, and I had hired an engineer from Eastern Region to assume Tom's old role as manager of programs and technical services but she did not start until August 1st of 2010. So Tom had transitioned, as I said, just earlier, so I guess technically at that time that role was vacant, although I had filled it with someone and she was in process of moving to Edmonton from Sarnia, Ontario.

Q. So that's the position that shows up here, manager of pipeline integrity programs and technical services?

A. Yes.

Q. It shows up as vacant on the org chart. Okay. So there was someone hired; they just hadn't started?

A. They just -- no, they were days away from starting.

Q. And that was Tom's previous position?

A. That's correct.

Q. Okay. And can you discuss a little bit, I'm unclear, as to what roles and responsibilities he would have had over materials and analysis? Can you talk about the differences?

A. Well, with programs and technical services that Tom looked after, all of the ILI procurement scheduling, the running of the tools, the initial, we'll say, dig programs were generated in that group. The technical services group was a relatively new group and we were looking to build that up to provide things like failure analysis, due diligence on projects we were looking at to acquire new assets. So they were looking at building that group up to do -- well, to provide services, really, to all the other three groups.

Scott Ironside was the manager of analysis and materials, so it was in that group, for instance, that Jeff, Ryan and Sean reported to and did all of our technical analysis on corrosion, cracking, denting and mechanical damage, and Scott was the manager, at that time, of that group.

So then, the materials group, which Sean headed up, included things like welding procedures. He also managed our crack programs, as well.

Q. So that group really is the same as it is today, the materials and analysis group?

A. In essence, yes, but as was noted earlier, with the new structure that's in place now we do have that extra layer of management and there is a layer of managers now that are overseeing the analysis group that's headed up by Jeff, Ryan and Sean.

Q. And Tom Zimmerman, you said that you were looking to build up to provide failure analysis support to the other three groups. What -- can you --

A. That have been one of the functions, yes.

Q. What was the nexus for that? Why did you determine you needed failure analysis?

A. Well, we had failure analysis. We were going to look to shift it into his group and give them more resources to work on failure analysis. I mean, some of the other things that that group looked after as well was the data integration and data management. We had a supervisor there, Greg Zinter, who was handling all of those processes for us and we were looking to and, in fact, we got some initiatives that we can talk about that we were working on from a data analysis and integration perspective that the group was working on under Greg, who reported to Tom at that time.

Q. Okay. So was Tom -- did he do a failure analysis on Marshall? Is that why he was out on the site?

A. He was involved in that. We had Mel Ansen (ph.), who I believe was also at the NTSB labs. He was part of the failure analysis on the Marshall incident, as well.

Q. Had Tom done failure analysis on Line 3?

A. I'm not sure.

Q. Maybe that's a question for Tom.

A. Yeah.

Q. Okay. And I think you were going to talk to us today a little bit about spending and budgeting on operations, as well.

Is that --

A. I can.

Q. Was that a --

A. With regard to integrity spend historically?

Q. Yes. Right. Was that --

A. Yes.

Q. -- one of your responsibilities back in 2010?

A. Yes.

Q. Okay.

A. Yeah.

Q. And can you talk to us a little bit about that process, how things were prioritized or decisions made to repair versus replace?

A. We had just started the process of repair versus replace, for instance. We had done, for instance, this program or process it started with some analysis on Line 3 and it evolved into analysis on Line 6B and we had used -- I guess, what we used as the basis, a report was generated by Matthew Thompson back in July of 2009 regarding the corrosion condition of Line 6B and in it, it indicated that it looked like there was a good case for pipe replacement due to the number of features that we had that were looking like they were going to be meeting repair criteria within, you know, the next, I would say, 5 to 10 years.

So we had developed a program, this was on the engineering side, that optimized our pipe replacement program and we were looking at a 19-segment, 30-mile replacement program initially for Line 6B. We had initiated discussions with our shippers and had given them sort of rough time frames and rough cost estimates and had initiated discussions on how we might recover that cost.

At the same time, going back to November 2009 and then again in March 2010, we had meetings with Central Region PHMSA and outlined our strategy and program for Line 6B going forward and, you know, we indicated to them in those meetings that we were looking to replace portions of Line 6B and that we had, you know, started discussions with our shippers on how we might recover that cost. Because at that point in time that program was looking like it was going to hit, with all the repairs and the pipe replacement, close to a quarter of a billion dollars in size.

Q. What milepost were you talking about replacing; do you know?

A. Yeah. We were concentrating primarily on Milepost 650 to Milepost 720, which is from the Stockbridge take-off to about 40 miles downstream, or thereabouts, from Howell Pump Station.

MR. CHHATRE: Whose pump station?

MR. IRVING: The Howell Pump Station, I believe, is at Milepost 678. So we were going like for -- you know, we were looking a the section that would go about 42 miles downstream of Howell Station. When we had a look at the, you know, the ILI results, that 70-mile stretch -- and it was really focused between

Milepost 650 and 700, although there were small chunks downstream from 700 to 720, you know, that had some high density of corrosion defects that looked like within 10 years was going to hit the repair criteria when we applied our corrosion growth rate analysis to it.

BY MR. NICHOLSON:

Q. So these were all corrosion-related defects that were driving this?

A. The vast majority were corrosion defects, although we did look, certainly, at the crack defect population and we did see, particularly downstream of Stockbridge, that there was a crack population that needed remediation going forward, as well. When we did a cycling analysis, we did find that downstream of Stockbridge the cycling severity was a little bit higher than we wanted to see.

Q. Who performed that analysis?

A. Which analysis?

Q. The cycling analysis?

A. That would have been Sean Keane's group, would have done the cycling analysis.

Q. And you said you met with PHMSA in March of 2009?

A. Actually, in November of 2009 and then, actually, March 31st of 2010.

Q. So that was after the pressure restriction had been placed on Line 6B?

A. Well, now which pressure restriction are you talking about? Are you talking about the application that went in, in July of 2010?

Q. Yeah.

A. So it would have been before that we were talking to them. But at that point, though, back when we were talking to PHMSA we had point pressure restrictions on specific features, but when we put in our application -- the application actually went in, I believe, on July the 16th, 2010. It was roughly just 10 days prior to the incident.

Q. Right but the pressure restriction had been put in place, I think, July 17th in 2009, right?

A. Oh, yes. You're right. Yeah, that was a date of discovery. Right.

Q. Okay.

A. And we were looking to complete repairs by July 17th, 2010 because that was the 365-day interval. That's right. We had point in point pressure restrictions on a feature-specific basis back in July of '09.

Q. And PHMSA was aware of this even before you published the 2010 notification. When you met with them, for instance, in November of 2009, were they aware of these point restrictions or the line restrictions, pressure restrictions?

A. I'd have to check that detail in the presentation.

Q. Do you still have that presentation that was given?

A. I do.
Q. Okay. Can we get a copy of it?
A. Sure.
MR. JOHNSON: Which, just so I know it's --
MR. IRVING: November 17th, 2009 was a meeting --
MR. JOHNSON: November 17th presentation.
MR. IRVING: Yeah, it was a meeting in Kansas City.
MR. JOHNSON: Okay.
MR. IRVING: And then there was a further meeting, as I mentioned, on March 31st of 2010.
MR. JOHNSON: And your presentation then also, Steve?
MR. IRVING: Yeah, there was.
MR. JOHNSON: So that was -- what date was that? So I might as well --
MR. IRVING: March 31st, 2010. That particular meeting covered a wide range of topics, actually, because we did a lot of, I'll say, presentation on the Line 2 --
MR. JOHNSON: So, I'm assuming you want both of those, Matt?
MR. NICHOLSON: Yeah, I'd like to see them.
MR. JOHNSON: All right.
MR. NICHOLSON: I'm curious to know what was said to PHMSA about this, if they were aware of prior to the notification in 2010.
BY MR. NICHOLSON:

Q. And so as you recall from this meeting, they bought off on this plan to replace and --
A. They -- yeah, they didn't have any objection. We talked about the strategy that we were going forward with and they didn't offer up any objection to it.
Q. So the paper that Matthew Thompson had written that was driving this replacement project, that was based on a 2007 ILI run; is that correct?
A. That's right.
Q. Okay.
A. As well as, I believe, there would have been supplemental information, perhaps, from the 2009 ultrasonic ILI run, as well.
Q. And that 2007 run had to be reissued three times. Were you aware of those --
A. Yes.
Q. -- reissues?
A. Yeah.
Q. And can you talk to the reissues and what it was and why it was held up?
A. Well, the -- and I'll go back a little bit farther in time. In 2005, 2006, you know, we became, I'll say, more aware of the implications of the echo loss issues that we were seeing on the ultrasonic runs. And we actually went back to the vendor, because once we really had a hard look at the data, we actually

felt that the runs did not give us the data quality that we were looking for and we actually came back with and had some negotiation with them to redo up to 13 runs in the U.S. and Canada as a result of the echo loss issues that we were seeing.

So that whole program, you know, we just had trouble with the data around echo loss and we went back and forth with the vendor, who was GE at the time, on these runs and, you know, we were -- we just had issues with their data quality. And so we initially looked at those 13 runs not as reestablishing the baseline but really as a supplemental run to the runs that we thought or that we considered the baseline because we wanted to add the specific information that the echo loss that had been provided on the previous runs wasn't giving us.

So we were, you know, looking to supplement that information. You know, so there was a lot of back and forth over that period between 2007 and 2009 with GE. I was aware of those multiple reorders or, I guess, reissues, I should say, of those runs.

Q. So if we're talking echo loss, we're talking ultrasonics?

A. That's right.

Q. So the 2007 run wasn't MFL; it was an ultrasonic run?

A. No, I believe the 2004 run --

Q. Okay.

A. -- was the ultrasonic run and it was the issue with that, because that run we considered the baseline assessment because that would have been the first run on 6B after the IMP rule came out.

So those runs that I referred to, you know, we were looking to run an MFL, you know, to augment, you know, the ultrasonic runs because we, with the echo loss --

Q. Okay.

A. -- we felt that the MFL was going to provide that missing data, you know, for the deep pitting that we were missing on the ultrasonic runs.

Q. Okay. So if I understand it, the echo loss issue was a problem you had with the 2004 run, and in 2007 you were running the MFL to fill in gaps that you believed you had in the 2004 run?

A. Yes.

Q. But then that 2007 MFL run was also sent back for reissue, was it not?

A. That's correct.

Q. Yeah. Okay. I'm not sure I understood, then, why the 2007 was sent back for reissue. Can you talk to that a little bit? I know it's been a while.

A. Yeah. Well, the information here, you know -- and what I'm referring to now is the report that was put in. The volume of data to analyze and integrate the MFL data with the existing UT data actually overloaded the ILI vendor's analysis capabilities and caused that final MFL report to be not even received until

June of 2008. So it took them the better part of a year, actually, to actually get through the analysis work.

Q. Okay.

A. And so it was then trying to fit it together where we had the issues, you know, with the ultrasonic that ended up with the reissues.

Q. Okay.

A. And at this time I would probably say the marrying up of those two technologies and trying to overlay them was probably new to the industry and it was certainly new to us, so we were kind of learning how to do that as we were getting the data and that's what resulted in a whole lot of back and forth with the vendor at that time, until we felt that we had good matches between the two different types of runs.

Q. So the first delay was just them having to analyze a very large amount of data.

A. That's right.

Q. Okay. And is that unusual?

A. I would say so, yes.

Q. I thought I heard earlier in one of the presentations that there were methods of prioritizing or staging data so that you didn't have those kind of issues. Is there something in place that --

A. Well, I would say that what they refer to probably has been procedures that have been developed as a result of that experience we had in trying to put those two different technologies together in one coherent piece.

Q. Okay. And then you're saying the subsequent delays after you did get the data back was just overlaying the MFL data on top of the UT data --

A. That's right.

Q. -- and finding a good fit or correlation between the two?

A. Yeah.

Q. Okay. So I guess date of discovery then cannot occur until you'd gotten that mesh?

A. That was our position at the time that, you know, without what we felt was good quality data we couldn't pick -- or couldn't establish a date of discovery because we didn't have data that we understood fully.

Q. Who makes that determination, date of discovery? Is that your group? Would that have been your group at the time or compliance?

A. No, it would have been the analysis group. Or, well, I should say probably a -- I'll say a joint decision between the programs group and the analysis group. The programs group would likely make the call but if they had problems with the data, as they would have in this case, they would have brought the analysis group in and then, you know, with issues like that it would have been a joint call. Although the programs group if we've got good quality data and we're getting good correlation, you know, initially in the field with some of our calibration digs, the programs group -- and this is the group that runs and schedules the ILIs and prepares the dig lists -- they would make the date of discovery call, the program managers in that group. But when there's issues and they have to bring in analysis for more technical work, that would be a joint decision between the two.

Q. And I think as the PHMSA rule reads you have -- is it 180 days after date of discovery to notify PHMSA, or --

A. I believe so. Jay, do you --

Q. Is that how that works --

MR. JOHNSON: We have 180 days to make date of discovery after the tool leaves the trap.

MR. IRVING: Correct.

MR. NICHOLSON: Okay.

MR. JOHNSON: And if you can't meet that, you would write a justification of why you couldn't. You don't have to make the announcement on that. Or you don't --

MR. NICHOLSON: So why ---

MR. JOHNSON: -- have to alert them on that.

MR. NICHOLSON: Was there a justification then issued to PHMSA?

MR. JOHNSON: My -- you know, and I can't address that. I know that some of the things that Steve's talking about when they met with PHMSA because, you know --

MR. NICHOLSON: Okay.

MR. JOHNSON: -- it's assuming you have good data.

BY MR. NICHOLSON:

Q. Now, when did you have good data? It was 2008 or -- on that timeline you've got in front of you, Steve?

A. I believe it would have been 2009 --

Q. Okay.

A. -- by the time we were satisfied with the good data. From the initial run it looks like the 180-day date of discovery deadline was pegged at April 10th, 2008. So that would have been from the, I guess, the day the tool came out of the trap, backing up 180 days from that into 2007.

Q. Okay.

A. In fact, yeah, the MFL tool run date is listed as October 13th, 2007 and then the 180-day date of discovery is April 10th, 2008. But it wasn't until June the 4th, 2008 that we received the first report.

Q. Okay. And then sometime after that, because you would have had to have analyzed it.

A. That's right. Yeah. So then that led through 2008 and into 2009, as you mentioned, the three reissues, and then July 17th, 2009 there was a date of discovery and the pressure restrictions imposed, and that would have led to the July 17th, 2010, 365-day period where we put in our application on the pressure restrictions.

Q. But then again, you didn't meet with PHMSA until November 17th, 2009, right?

A. Right.

Q. So there was no notification to PHMSA anytime prior to that that, hey, we're having issues with this analysis and date of discovery's going to pushed out. It was only after the pressure restriction was put in place that you met with PHMSA. Am I -- is that right on the -- have I got that right on the timeline? Because if July was your --

A. Yeah.

Q. -- pressure restriction --

A. Yeah, I think that's right. Yeah.

Q. Okay. Okay.

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

MR. CHHATRE: Yeah.

BY Mr. CHHATRE:

Q. I'm trying to understand the relationship at the time of the accident between risk management and integrity management and what are the boundaries what risk management does and what integrity management -- I mean, did -- integrity management did at the time of the incident?

A. The program that we ran at the time in risk management was an index-based risk model. And we would have received input on threats from the integrity group, and we would have run our risk-based, or I should say, our index-based risk assessment on, at the time, 1,000-foot sections without our pipeline system. So every pipeline was divided up into 1,000-foot increments and the risk -- and this would have been because it's an index model -- a relative risk score would have been generated on each 1,000-foot section.

We have since made some significant changes to our risk program. We have now, just in the last year, developed a semi-quantitative approach and we use a, I guess, a dynamic segmentation architecture to identify our risk segments. That took the number of segments that we had a risk profile on from about 72,000 segments now down to just over 16,000 segments. So we have a more manageable database and we are, you know, at this point in time we're still looking to get approval on that new architecture as well as the semi-quantitative approach from executive management. In fact, probably, within the next 2 to 3 weeks we'll be talking to them about getting concurrence on our new approach, although we have certainly given them updates on our approach and our progress on it over the course of the past year.

Q. So integrity management provided the list of risks to the risk management group, and then they ran the program and identified the segments and ranked them in a relative risk --

A. Well, they would give us data on a segment-by-segment basis on the threats that were specific to that line. You know, for instance, you know, to use Line 6B as an example, they would have given us data on internal corrosion, external corrosion, cracking, denting, and our model then would have, you know, produced a risk profile for each and every line segment in our system.

Q. And what numbers the risk management will be giving you then? I'm a little bit confused. They will give you -- you said, they give you some kind of a number for each segment and you will take those numbers and put through some model and get the relative risk ranking for each segment; is that correct?

A. That's correct. Yes.

Q. And so the risk management group, now, what kind of numbers they were giving you? Those numbers are what, based on --

A. I'm not sure I follow your question.

Q. Okay. Where I'm confused and maybe you explained it, but maybe explain again --

A. Yep.

Q. -- integrity management give the threats to risk management, these are the threats for each segment, each 1,000-foot segment --

A. Right.

Q. -- is that correct?

A. Yeah.

Q. And then risk management took those threats and went through some kind of a model, I guess, and gave integrity management back numbers for each segment: corrosion risk number is such and such, and --

A. Well, we -- the numbers that would have been generated would have been a relative risk number within the model. For instance, you know, risk obviously is probability times consequence. You know, essentially the pipeline integrity group have been involved primarily -- well, really, with the probability side. And the operational risk management group, you know, took that information, looked at consequence and came up with a relative risk score.

So, for instance, they would have generated in this index model a dimensionless number. Say, 14.2, would be a number of a particular -- the risk number for a particular segment. You could then take that number and compare it to, say, another number within that pipeline -- within our pipeline system or within that pipeline segment. And let's say if you wanted to compare it to something, say, 10 miles away and that number was 10.4, well, then you'd know that that segment that had the score of, you know, 14.2 had a relative risk ranking that was higher. So that would have a higher risk, per se --

Q. So lower the number, higher the risk?

A. No, no, no, the higher the number, the higher the risk.

Q. Okay.

A. Yeah.

Q. I just want to make sure. Okay.

A. Right.

Q. So it was the risk management group that ranked your entire -- Enbridge's pipeline with 1,000-foot sections and gave a relative risk ranking; is that right?

A. That's right.

Q. Okay. And how did integrity management came up with the risk factors for each 1,000-foot segment? That was based on what?

A. You'd have to get the specifics from the integrity group as to how they gave the information to the ORM group.

Q. Any particular person in the integrity group that you are aware of?

A. They would have received -- actually the three gentlemen that were here earlier probably would have fed them the bulk of the information.

Q. Okay.

A. Our model was based on percentages of -- you know, on a particular line segment or, I should say, percentages of corrosion, cracking, you know, denting, ground movement, human factors, you know, like operational errors, all played into this. So they collected data from a number of different groups within Enbridge, you know, to run the risk model. But you'd have to get the specifics of what they actually supplied --

MR. JOHNSON: And we're going to be talking to David Weir, Wednesday afternoon right now.

MR. CHHATRE: Okay. I just wanted to (indiscernible) --

MR. IRVING: And he can give you the details of how they received that information.

BY MR. CHHATRE:

Q. I think one of the slides here -- when the baseline assessment was completed, do you know?

A. For which?

Q. For the integrity management program. With PHMSA you are required to finish the baseline assessment with a certain deadline.

A. Right, and those --

Q. If you could (Indiscernible) look for my notes here.

A. Yeah, the dates were -- in fact, I wrote this down. You had to have 50 percent of you pipe in what they called Category 1 complete by September 30th, 2004.

Q. Right.

A. And then you had to have the rest of the pipe done by March 31st, 2008. Now, there's another date in there, as well. That was for pipe that existed on May 29th, 2001. So I believe for any pipe that was placed into service after that date you had to have and IMP program -- I think it was within one year of an in-service date. We met all of those dates. In fact, we exceeded them with our integrity program.

Q. Yeah, because you finished the baseline before 2008 sometime.

A. Yeah. Yeah.

Q. And these runs in 2004 and 2005, and '7, which are sent back for data, did that change any baseline ranking for these segments? Especially the rupture segment, did that change any?

A. I'd have to defer the answer to that to David Weir's group if it increased the risk on that.

If you could make note that --

MR. JOHNSON: Oh, they're going to be talking to David, so -- unless that's a specific IR?

MR. NICHOLSON: Well, I'm typing it up now. Do we have that -- do we have the risk rankings for this line submitted to us yet?

MR. CHHATRE: I just went through quickly and I just started on it after I came back from India. So I went through quickly, but I didn't see any. That's what got my --

MR. NICHOLSON: Well, I'm looking at Jay. I thought he might have it. We want to see the factors and the rankings for Line 6B from 2005 till 2010.

MR. JOHNSON: 2005 to 2010?

MR. NICHOLSON: Yeah, through 2010. I assume that's done on an annual basis?

MR. IRVING: Yep.

MR. JOHNSON: I've got that down and I'll just ask David Weir if that's something he's provided already.

MR. IRVING: I don't think he has either.

BY MR. CHHATRE:

Q. Can you elaborate a little bit -- I didn't take it down very well, I guess. You said semi-quantitative approach and then there were like 72,000 segments and you guys got it back to 16,000?

A. Right.

Q. Can you elaborate what that -- what those numbers tell again one more time?

A. Sure. So with our system with the index model we had approximately 72,000, 1,000-foot segments that would have been ranked on the relative risk ranking score. When we -- we're in the process of converting to the semi-quantitative approach now. We employed a technique called dynamic segmentation where we took key risk factors and grouped our pipeline segments that had all those similar attributes and what that did was it reduced those 72,000 segments down to approximately 16,000.

Q. Okay.

A. And, you know, some of the attributes, for instance, would be, you know, was it an -- is it an HCA? Is it a water crossing? We also used coating type, age of pipe. We even used pipe diameter because, obviously, the consequence of a spill from one of our 48-inch pipes could be potentially greater than, say, a spill from a 20-inch just based on volume alone.

So we had a number of factors just as I've mentioned and that has, you know, given us an architecture where right now with our existing system we're looking at about 16,000 segments of our pipeline system to risk rank.

Q. So now is it -- is it correct to say that now the segment lengths will change depending upon --

A. Yes.

Q. -- the attributes?

A. Exactly.

Q. Your footage is still the same?

A. Yes. Footage is still the same, but, you know, for instance, if we had 5 miles of running through the prairie, you know, that 25,000 feet would have been, you know, divided up into 25 segments. If it did not cross an HCA or a river and have the same coating, that could be one segment now, for instance. So, you know, we've tried to look at it with those different attributes.

Q. And when did this change happen, before the accident or after the accident?

A. Oh, no after.

Q. After the accident?

A. Yes. Clearly, after. We've been working on that this year in 2011.

Q. So before the accident your 1,000-foot section could contain different pipe diameters depending upon, you know, how you cut in?

A. Not likely, when you parse it out that small. I don't think so. There's the possibility that there could have been a very, very small number but I kind of doubt it, actually, because -- well, I guess there's one line that it could be the case and that's our Line 4 because it does go from 36 up to 48 down to 36 and then back up and it does that 29 times. So there is the potential on that line where you could see that happen. Yeah.

Q. Now, the date of discovery you mentioned in Matt's question that was discussed with PHMSA in one of the meeting, I believe somewhere in -- sometime in November.

A. Um-hum.

Q. Was PHMSA okay with that date of discovery as being the acceptable date of discovery considering or compared to with actually the run was made?

A. I don't think we actually addressed the date of discovery at that meeting. That was not addressed.

Q. I guess maybe --

A. I'd have to, again, refresh my memory on that, but I don't think it was.

Q. Okay. Did Enbridge receive any response from PHMSA at all about the date of discovery that you guys, I guess, assumed was okay with PHMSA or was not okay with PHMSA?

A. Well, I think under the rule we just -- do we not just have to document it for, I guess, a later inspection during an audit on what we've done there?

MR. JOHNSON: When PHMSA comes in, as they did for an integrity management inspection, they will look at your dates and if you went past their prescribed dates, then, you know, why did you go past that? That would be when they would look at the documentation of why you missed that date.

MR. CHHATRE: Okay.

MR. JOHNSON: Unlike a dig, once you've done a date of discovery, digs have specific time frames.

MR. CHHATRE: Right.

MR. JOHNSON: If you do miss those, if you go past 180, for instance -- we're using that example, then you would notify PHMSA that you're missing that and give them a reason, you know, on how -- not only did you miss it but what safety measures did you put in place. But the actual missing the date of discovery is an internal documentation that would be found during an inspection.

MR. CHHATRE: I understand. Okay.

MR. JOHNSON: Yes.

MR. IRVING: Now, when we did make the presentation to PHMSA we did state that when we were going to take the pressure restrictions that we were -- we would be doing so to maintain the 1.39 safety factor.

MR. JOHNSON: I don't know that PHMSA actually gives approval letters, if that's what you're looking for.

MR. CHHATRE: No, no. I mean, they didn't cite you. That means they accept it.

MR. JOHNSON: All right.

MR. CHHATRE: Right?

MR. JOHNSON: I can't answer that.

MR. CHHATRE: Okay. That's fine. Let me put it this way, you guys didn't hear anything about PHMSA saying the date of discovery was not acceptable or --

MR. JOHNSON: That would be a good assumption, yeah.

MR. CHHATRE: Right.

BY MR. CHHATRE:

Q. Now, going back to the risk management group again, so is that their sole function just to rank -- make a ranking, all the different segments before the accident? That's all the risk management did?

A. We would -- well, we also disseminated that information through a committee and discussed the results of the risk ranking with the group in operations, and that group would then be tasked with developing a risk mitigation strategy.

Now, since then, you know, in our reorg post-Marshall we have now established a -- I'll call it a project execution group within the risk group to make sure that those projects get done. Before Marshall it was at a lower level within the company and looked at with a regional group of operations people, primarily. You know, there were risk people at that meeting as well, though, and they discussed what to do with some of our higher risk pipeline statements.

Q. And how many people were in the risk management group before the Marshall incident?

A. I can get you an exact number, but I'll have to take that as an undertaking.

Q. Okay. Maybe you can make a note and get back to us?

A. Yeah.

Q. I don't have -- you know, interview you to answer that as long as we get the number.

MR. JOHNSON: You want the -- just so I can be -- you want to know the number of people --

MR. IRVING: Pre-Marshall, the number of people --

MR. CHHATRE: In risk management group.

MR. IRVING: -- in the risk management group, the ORM group.

MR. CHHATRE: And I'd also like to --

MR. JOHNSON: I'll put pre and post.

MR. CHHATRE: Pre and post, yes. And who did the rupture segment ranking?

MR. JOHNSON: Yeah, and I think that -- we'll ask that of David Weir when he comes in.

MR. CHHATRE: Yeah. Okay.

BY MR. CHHATRE:

Q. So pre-Marshall the risk management group, I guess, outlined the strategy and integrity management will discuss that strategy in a group setting with the people. Is that correct?

A. The information would have flowed back from the integrity group to the threat managers within integrity and, you know, they would have then made decisions on -- you know, for prioritization of programs. You know, they might, on a high-risk segment, they may look at repair criteria. They might look at potential ILI changes in terms of interval setting.

Q. The risk management will send their risk mitigation strategy to integrity management, to supervisor, I guess?

A. Well, it wouldn't have been so much the strategy. It would have been, really, the raw numbers from the relative risk model that we were using at the time.

Q. Okay. And was there a, I guess, separation as to high risk, medium risk, low risk, or whatever -- you have so many segments, what was the cut-off, I guess, cut-off line or number that will bring somebody's attention?

A. We did not have criteria on that established.

Q. So who --

A. We would have done a distribution ranking on the risk scores and, you know, when you look at the distribution sometimes there's a natural break in how the risk scores are generated. We would look at, well, say, using techniques like that and then look to see where that high-risk -- where those high-risk numbers were or segments were located and potentially then look at the distribution to see if there was a logical cut off to where we looked at risk mitigation strategies.

We did, though, develop a -- I guess it was a top 10 list, if you want to call it that. Although, in essence, we actually developed a top 15 list and we looked at LVP, HVP and then we also looked at the higher consequence areas from an integrity perspective on LVP and HVP.

So we have kind of a top 15 list for each of those four areas and that was discussed at the risk committee level and they would then look to determine whether we had sufficient mitigation in place in those top areas.

Q. Bear with me, Steve. I'm still trying to --

A. Yep.

Q. -- get my (indiscernible) straight here.

So the risk management sent you 70,000 segments and identified the numbers, the raw numbers for each segment?

A. That's right.

Q. And integrity management took those raw numbers for each segment and did what? That's where I'm lost.

A. Yeah, I'm not sure that they got all 72,000. They may have received the top risk areas. I think we would --

Q. That's my question, how --

A. -- we'd have -- that would be something for David Weir to answer.

Q. Okay.

MR. JOHNSON: And maybe I'll stick in a question here. Certainly, while pipeline integrity is giving information to the ORM group as far as risks that they've determined from the tool runs, while that work is being done integrity is still focusing on the severe defects. They're not waiting for information back from

ORM.

MR. IRVING: Oh, that's right. Yeah.

BY MR. CHHATRE:

Q. And that's where I was heading at before is that you only have raw numbers; you don't have the ranking from risk management so how will you know what are the high risk that you need your attention without waiting for any other information from different groups? How will you know from those 72,000 or however many segments are given to you by integrity management, how will you know which ones to pay attention to?

A. Well, the top risk areas were identified. So, for instance, in that relative ranking model, I believe the top risk number, you know, was -- the number was like 22. The ORM group developed, you know, like the average, what the top risk number was, you know, for different pipeline segments within our system.

MR. JOHNSON: Maybe where we're trying to go here, Ravi, maybe I'm sitting back hearing it -- so the risk numbers for pipeline Integrity helps them prioritize when you have 20 digs which ones to focus on first. It doesn't change the 20 digs that integrity is going to do. When you're going out there if you've got 20 digs and, supposedly, if they were all equal, the numbers from the risk management group would say, you know, try to get to these first. But integrity is still going to dig out 20 no matter what the risk number is because it meets the criteria of what has to be dug.

MR. IRVING: You know, and further to protect the specific, we'll say, segment that may have a number of digs on it, they would have placed point pressure restrictions to restore the full margin of safety on that point pressure restriction.

BY MR. CHHATRE:

Q. Can you elaborate for me LVP and HVP, what do they stand for?

A. Oh, low vapor pressure and high vapor pressure.

Q. That's what I thought, but I just want to make sure.

A. Yeah.

Q. Okay.

A. So we have, like, Lines 1 and 5 in the Enbridge system carry NGL batches.

Q. Um-hum.

A. Whereas, all of our -- as well as Line 1 in Canada also has refined products. All of our other lines have the crude oil in it from light to medium to heavy, sour, sweet, or et cetera.

Q. So four areas you mentioned earlier was LVP, HVP, high consequence and what else? I only have three. You said there are four areas that --

A. Oh, it would have been the top risk scores for HVP and LVP.

Q. Okay.

A. And then the top risk scores from an environmental perspective for HVP and LVP. So they were the four areas.

Q. Okay.
A. Okay.
Q. And then environmental perspective is the high consequence; is that what --
A. Sorry?
Q. Environmental perspective is included in the high consequence? Is that what --
A. Yeah. That's how we -- you know, we wanted to get a perspective of, you know, taking the probability out of the equation where were the high consequence areas. And, you know, as you can imagine in the top 15 list there was some overlap there because, you know, if it was a consequence driver it would show up on both lists.
Q. Okay. So I guess so far, I think I understand, risk management sends information to integrity management, then integrity management -- another group in integrity management called threat management group that will handle the --
A. Well, that would have been the analysis group. They're the subject matter experts when it comes to identifying the specific threats.
Q. Okay.
A. So, you know, you've got Sean that looks after cracking and Ryan that looks after both internal and external corrosion and Jeff looks after the mechanical damage, the denting and the geometry.

Q. So what are the process in place in case -- which segment gets attention first? Some may have a high number with general corrosion, with MFL. Some may have crack. What are the process in place to decide which ones get the first attention?

MR. JOHNSON: Is that better asked -- answered by David or maybe one of the integrity guys?

MR. IRVING: Well, it's probably a combination of David and the integrity guys, how they deal with that, yeah.

BY MR. CHHATRE:

Q. When you say integrity guys you mean whom?

A. Oh, the threat managers, Ryan --

Q. Okay.

MR. JOHNSON: Probably Ryan.

MR. IRVING: -- Sean.

MR. JOHNSON: Ryan, he's going to be back next -- Ryan's way up on that.

MR. CHHATRE: Okay.

BY MR. CHHATRE:

Q. And how does the program differ now? And I guess now I have a little bit better understanding as to how it worked before accident. What has changed now?

A. What has changed now? Well --

Q. If it has changed, and do not -- I guess right now you have combined the two units under one management, right, risk and integrity management, or no?

MR. JOHNSON: Separated.

MR. IRVING: No, they're separated.

BY MR. CHHATRE:

Q. Now?

A. Now, yes.

Q. And they were under one before?

A. Pre-Marshall they were under myself, yes.

Q. Okay.

A. Now, we report to Art Meyer, so, you know, which level do you want to, you know, do you want to go to? I mean, Art Meyer is now the senior VP of pipeline integrity and engineering of which, you know, my group is a part of.

Q. Okay.

A. But, you know, if you wanted to look at the director level, they are separate.

Q. Okay. But how do they -- how does the interaction work now? I mean, do you continuously redo the ranking or the ranking is kind of fixed now?

A. Well, we're -- actually, because we're in transition we have not run a ranking yet under the semi-quantitative model because we're still gathering data to input. The data requirements for the semi-quantitative model actually went up, probably, by about a factor of three. And the program that we have laid out is that by the end of this year -- so we're talking 3 to 4 weeks from now, the data gathering process for our semi-quantitative approach will be complete. And the idea is that we are going to take that data, run it early in the new year and then be able to provide the results of the risk ranking from a semi-quantitative approach to start our budget process which starts early in 2012 for the 2013 cycle.

Q. And that -- I think you are saying you are still awaiting the approval to do that?

A. And we -- yeah, and in the meantime we still need to get executive management approval, and we're going to be meeting with Art Meyer here before Christmas, actually, to review that. It may carry over because I believe he will want to bring this to the executive management team, which would be all of his peers. And we'll be doing that probably in early January to get, you know, full sanction from our executive management group on the approach that we're going to take.

Q. So when you say integrity management group, does that mean more above the vice president that you report to or --

A. It would be -- the executive management group would be the vice presidential level and above. So it consists of a number of vice presidents and senior vice presidents that report to the business unit leader which is Steve Wuori.

Q. So --

A. Now, the executive management group also includes two directors: one for IT and another one in HR. They're at the director level, but everybody else in that group would be VP or senior VP.

Q. Okay. So until that point, the old system still is in place about ranking and relative ranking?

A. The old system is still in place? Yeah. We have data on the relative rank system, you know, that we've used this year.

Q. So what happens to that system as you run more and more ILI tools and more information becomes available, how often that thing is upgraded, the rankings I mean?

A. Well, as soon as it becomes available to -- from pipeline integrity, you know, that'll be one of the touch points that we've identified that they'll need to send the ORM group the new data that results from an ILI program and then a subsequent dig program.

Now, depending on the line location and, let's say, where its risk ranking falls with the new information, we may decide to rerun it right away or it's possible we could also let it sit and run it with the rest of the program. Those determinations still need to be made yet on what the frequency will be on how soon or how often the risk ranking will be done. At an absolute minimum, the entire system would be done once a year. But, you know, again, depending on where a particular dynamic segment falls and, let's say, its risk history, we may decide to do an update sooner rather than later, you know, when we do the catch up with everything.

Q. So is there a procedure in place to do that or it's kind of a --

A. No. We have -- we've just developed, and again we've got Art Meyer's first draft comments on our risk framework. What we're doing is we've developed over the course of the last year a risk management framework that will be compliant with and compatible with ISO 31000. That's, you know, the international standard for risk management. So we have modeled our new system and all the framework that will go around our new risk ranking process on ISO 31000. And --

Q. But that's in the future?

A. That's going forward, yes.

Q. Right. But I guess what I'm saying, until all these things, you know, management approval comes in and all these things happen, right now you still have the old system in place, right? I mean --

A. That's right. Yeah.

Q. And my question with the old system is, is there a written procedure that tells either the risk management group or integrity management group how do you re-work the ranking as the information comes --

MR. JOHNSON: I think David Weir can talk about how he does that and the schedule in which he brings in the data and grinds the new numbers.

MR. CHHATRE: Okay.

MR. IRVING: Yeah.

MR. JOHNSON: David Weir will tell you that.

MR. CHHATRE: Okay. But I guess, make a note, if there's a procedure I'd like to get a copy of that. If there is a procedure for that --

MR. IRVING: Okay.

MR. CHHATRE: -- for doing that. If there's no procedure, that is fine, and then we can just get informally --

MR. IRVING: Yeah.

MR. CHHATRE: -- what we need. But if there is a procedure --

MR. NICHOLSON: What's that request, Ravi?

MR. CHHATRE: We see the old system with 1,000 feet per segment right now, and the question is, as the new information becomes available a new leak, maybe a new ILI information for each segment, then what is the procedure for that new information to get integrated into the risk calculation and the baseline numbers? Do they change or they don't change? Is there a procedure in place to do that, yearly, 6-monthly or something like that?

MR. IRVING: I think it's every year, but David can confirm that.

MR. CHHATRE: Right. And if it is informal, then we need to know if it's informally done as the information becomes available and either way.

MR. IRVING: Sure.

BY MR. CHHATRE:

Q. Now, has the integrity management program been revised since Marshall in terms of details? And I don't need to know details from you, but I just want to know if it's revised or --

A. I'm aware that they have done a fairly significant overhaul of the integrity management program and procedures. I know a lot of the procedures that, you know, that were referred to by Ryan, you know -- I think they're identified by numbers like PI-25, 27 and so on. I believe they've all been updated and revised within the last year to year-and-a-half. But you'd have to get confirmation from them --

Q. Sure.

A. -- on that, but I'm aware that they've done quite a bit of work to revise and -- well, just to revise our procedures, yeah.

Q. That's all I have for you so far.

A. Okay.

MR. NICHOLSON: Okay. Brian, do you have any questions?

BY MR. PIERZINA:

Q. Sure. You doing all right, Steve?

A. I'm fine. I've still got water in my glass so that's all right.

Q. I wanted to ask you about the pipeline integrity operating program costs, historical --

A. Right.

Q. -- and bear with me here one second. We received a document breaking down integrity and maintenance costs between mechanical maintenance costs, integrity operating costs and integrity capital costs, and I'm just wondering if you could kind of distinguish between those categories what mechanical maintenance costs comprises and what integrity operating and -- versus integrity capital?

A. Okay.

Q. All right.

A. I'll start with integrity capital. Integrity capital would comprise primarily dig programs that would result from ILIs that would have been run on specific pipeline segments, as well if we were buying a cleaning tool, for instance, that tool would be capitalized. We buy a number of cleaning tools, as you can imagine, of various diameters and they would be bought under a capital purchase program.

As far as the operating costs go, what would be included in that would be the actual ILI runs themselves. So if we were going to run on a segment a corrosion tool, it would normally be coupled with a geometry tool. Those costs from the vendors that supply those services would be expensed, you know, on a yearly basis.

The other big expense that we would have would be corrosion inhibitor, for instance. It would be expensed as a -- it would be purchased on a yearly basis. If we had, you know, existing tools that just required refurbishment parts like cleaning tools, you know, or buying new brushes, perhaps new disks, they would be expensed, as well.

Now, can you give me a little more description about mechanical maintenance? I'm not sure I can give you an answer without maybe a little more detail as to what --

Q. Yeah, it's just headed mechanical maintenance costs. So I'm just wondering if that might be, you know, facilities maintenance, you know, maybe -- I don't know, new traps or something or if that would be a capital cost or --

A. That's right. New traps, you know, and we've had to -- we've had a program to install new traps over the course of, you know, the last 10 years because as the tools have become more sophisticated, generally the length of the tools has grown substantially. So we've had to modify our sending and receiving traps, and they would typically be capitalized as an asset improvement.

Q. So that --

A. Now, the mechanical -- and I'm not -- can you give me an idea of what kind of dollars that are in that?

Q. Oh. So, let's see, I guess they range over from 2000 to 2010 from 56,000 up to 349,000, so --

A. Per year?

Q. Right. So not a huge number compared to --

MR. NICHOLSON: Brian, can you just tell us what document you're looking at?

MR. PIERZINA: It's Pipeline Integrity Operating Program costs.

MR. NICHOLSON: Not an IR?

MR. PIERZINA: It was part of the CDs that you -- that were provided to you.

MR. NICHOLSON: Okay.

MR. PIERZINA: Or to the NTSB and then subsequently --

MR. NICHOLSON: Okay. As part of the internal investigation background notes? Okay.

BY MR. PIERZINA:

Q. So yeah, just there are three columns: mechanical maintenance costs, integrity operating costs, and integrity capital costs. And it wasn't clear to me what those columns meant so I --

A. Yeah.

Q. -- thought maybe you would --

A. Well, I gave you the description on two of them. We'd have to get back to you on what's involved in that third one. Certainly, knowing what the operating capital costs were it would be a very, very small fraction of our overall integrity program. But we'll get back to you on what that mechanical --

MR. JOHNSON: It's called mechanical maintenance?

MR. IRVING: Mechanical maintenance. I'm just wondering if we refer to it something a little bit different in our own program documents because that's not a term that we would use.

MR. JOHNSON: It doesn't make (indiscernible) don't need to know that.

BY MR. PIERZINA:

Q. And, I guess -- and still I realize you're at a huge disadvantage not having the document in front of you, but so the integrity operating costs are running, you know, from 1.6 to $2 million per year, you know, over several years, and then in 2009 it drops to a value of $242,000. So there's a significant drop in dollars for 2009 compared to the previous 6, 7 years.

A. Now, are you -- would this be on a specific line because from a --

Q. No. This was -- I think is company-wide.

MR. JOHNSON: And it's which one again, Brian?

MR. PIERZINA: It's called Pipeline Integrity Operating Program Costs.

MR. IRVING: We'll have to take a look at the document. That's not making a whole lot of sense to me because our operating costs in our programs run in the multi-tens of millions of dollars a year because we would put our ILI costs in there. So I'm thinking that's a very specific category of expense cost. I'd need more information to, I guess, give you an appropriate answer.

MR. PIERZINA: All right.

MR. IRVING: We'll have to get that from you and look at it.

MR. PIERZINA: Yeah, so if you describe the integrity operating costs as the tool runs and integrity capital costs as the dig programs, you know, essentially that actually helps quite a bit. But for that year, from 2008 to 2009, what I'm seeing is like a $10 million increase in integrity capital costs but a significant drop in the integrity operating costs. So it made me curious as to what was happening with those numbers, which I understand is hard to answer without -- but I guess, so the question would be, I don't know, was there -- is there a reason that you can think of for a significant decrease in integrity operating costs between 2008 and 2009?

MR. JOHNSON: We'll just look it up --

MR. IRVING: We'll have to look it up because the -- certainly, when I look at our LRP numbers, I mean, on operating costs, you know, in the U.S. the numbers I have for operating costs in the 2008 budget approach $12 million.

MR. JOHNSON: How about 2009?

MR. IRVING: And 2009 about $8 million.

MR. NICHOLSON: Well, where do you -- is that -- are you looking at that spreadsheet in front of you?

MR. IRVING: Yeah.

MR. NICHOLSON: Okay. Well, we want a copy of that.

MR. IRVING: This is a -- the spreadsheet that I've got here is a Summary of Operating and Capital Expenditures, 2001 to 2011. Now, up from 2001 through 2006 there are actual; there are forecast numbers after that. But, you know, we wouldn't have been too far off on our forecast numbers and, if anything, if we were off we would have been low. But --

MR. JOHNSON: So I've got that down, Matt.

MR. IRVING: Yeah. What I'd like to provide, actually, is our actuals as far up to the present that we could because, you know, I know that these numbers exist, you know, in actual form for '7, '8, '9 and probably even 2010. This particular form that I have just covers actuals up through 2006. But you can --

MR. NICHOLSON: What's that titled? What's the title of that?

MR. IRVING: It's System Integrity -- Summary of Operating Capital of Expenditures. And, actually, now that -- well, yeah.

MR. NICHOLSON: So that would capture what you talked about: the operating, the capital, and the maintenance?

MR. IRVING: Correct.

MR. NICHOLSON: Okay.

MR. IRVING: Yeah.

MR. NICHOLSON: All right.

MR. JOHNSON: All right. Next, Brian.

BY MR. PIERZINA:

Q. All right. And I apologize for being dense. The ORM was part of your group previously, or not?

A. Yes.

Q. Okay. It was?

A. Yup.
Q. And it no longer is or it still is?
A. Nope, it still is.
Q. Still is. All right. All right.
A. Yeah. Compliance and ORM are part of my present group. In fact, that is my present group.
Q. All right. So when we talk about referring to, you know, a better question for David Weir or something, that's because it gets maybe more detailed than -- okay.
With an incident the scope of Marshall, you know, and I think the latest costs I've seen are in the $550 million range --
A. The company has actually increased it to $700,000 or $700 million-plus.
Q. 700, okay.
A. Yeah.
Q. All right. Yeah, I think the last report I saw was 550 million, but --
A. Yeah.
Q. The question is, all right, given the consequence of a failure such as Marshall, has that affected the consequence rankings for ORM and risk modeling and such?
A. Well, what the Marshall incident drew our attention to was the fact that a tributary -- and in this case the Talmadge Creek, you know, was the conduit for the oil entering, you know, the Kalamazoo River. So as a result of that we've gone through

our entire system and identified all tributaries that cross our right-of-way that lead into larger bodies of water, be them, you know, like the Great Lakes or rivers and whatnot. And we are in the process -- we've now gathered all that data as of October 31st and now we're analyzing it to see how it will impact our consequence scores.

So that's been a fairly huge undertaking because, you know, as you know our system runs from Norman Wells in the Northwest Territories down into Alberta and then from Edmonton, you know, right through Canada down into the Upper Midwest and back into Canada. You know, it's thousands of miles of pipe and right-of-way. We've identified 2,500 potential water body impacts as a result of that analysis. So we are looking at the consequence of, you know, a spill into those water bodies and where potentially they could lead to. So, you know, that's going to feed into our consequence ranking once that analysis is complete and it will be in probably 2 months.

Q. Okay. And so does that analysis include some type of time to detect --

A. Yes.

Q. -- a leak?

A. Yeah.

Q. Okay. And what is that?

A. Right now we're running, I believe, in the program or we will run 10-minutes for detection and a 3-minute valve closure.

So we're looking at oil out, 13 minutes at full design rate and also assuming that it's a guillotine-type rupture where the full cross-sectional area of the pipe is open and running for those 13 minutes. That's what we've been using for oil out analysis.

MR. JOHNSON: And that changed from -- the 10-minutes now has changed from previously it was 5 minutes --

MR. IRVING: No.

MR. JOHNSON: -- to recognize?

MR. IRVING: No. That 10-minute rule, I think, has been in place both pre- and post-Marshall, but I think Kirk Burdis (ph.) is probably the one to answer that question.

MR. JOHNSON: Okay.

MR. IRVING: He's the VP of the pipeline control.

BY MR. PIERZINA:

Q. So the worst case guillotine rupture and a length of time and see how much product could flow down a tributary to impact a -- have you done any analysis of a, let's say, a leak that might be under the threshold of the leak detection system so that, you know, so that you're not going to recognize it until you get some type of external report or something which could likely go on a lot longer, and to see what that does as far as impacting?

A. No, we haven't done that analysis, Brian. You know, as you're aware, you could have a pinhole leak to something somewhat larger, you know, and, of course, depending on the size of line -- you know, the larger the line, we probably have sensitivity-wise a larger volume out needed to detect it.

Q. Sure. Yeah. All right. And then just to make sure, I don't think it was your intention to characterize the November 17th and March 31st meetings as specifically related to Line 6B, or was it?

A. Well, they were topics that we did discuss and we did devote a portion of each meeting to updating PHMSA on, you know, our strategy and approach on 6B going forward.

Q. Okay. And we can get those presentations, but I just know from being there and have the agendas that I know 6B wasn't even on the agenda for the November 17th one, and it was kind of added as an afterthought for the March 31st meeting. I just wanted to make sure that we didn't mischaracterize those meetings as being, you know, related to either, you know, the date of discovery or, you know, 6B integrity in general.

A. No, the focus wasn't on the date of discovery, for sure, yeah.

Q. Right.

A. Confirm that.

MR. NICHOLSON: You done?

MR. PIERZINA: Yeah.

MR. NICHOLSON: Oh, okay. Matt Fox, anything you'd like to --

BY MR. FOX:

Q. Yeah, I just had a question about the dynamic segments and are there any limits on the minimum or maximum length that each segment could potentially be?

A. No. We, you know, as I mentioned, there's a list of about six or seven attributes. If one of those attributes change then that would provide the cutoff for a particular segment.

Q. So is there -- do you have, you know, maybe what the minimum and max values would be or --

A. I know what the minimum is and it's something that I have to address with the group, but they didn't want to stop the process because it was going to probably delay our ultimate, I'm going to say, rollout in getting the results.

We have a 151 segments that are 10 feet long. That's the minimum. And so we -- I asked my group, we have to go back and take a look at that because that -- there has to be a reason and a 10-foot segment doesn't make a whole lot of sense to me. I'd have to, I guess, undertake to tell you what the maximum distance is. I don't remember it offhand, but I know it's several miles. Not too long but, I mean, we have that -- I have that data I just don't recall it --

Q. Right.

A. -- at the moment, but I -- that 151, 10-feet segments -- or 10-foot segments did jump out at me and so I did remember that. So we'll be taking a look at that and, you know, I'm hoping we can eliminate them but, obviously, provide a good reason why we can, but they're in the 16,000 right now.

Q. Okay. I think that's all I've got.

MR. NICHOLSON: That's it. Jay?

BY MR. JOHNSON:

Q. Steve, I -- you know, one of the things we'd asked Sonya to bring in and I know you brought it in, are some of the initiatives that the integrity group had in place prior to Marshall. I mean, we certainly we talked to people about all the things that are going on since Marshall, but I know quite a number of things were going on prior to Marshall and if you could just touch base on those?

A. Sure. I've got it divided up into a number of different groups. The first one was data management and integration and we had developed an ILI QA/QC SharePoint site and this was set up as a multi-disciplined team and it included a number of different groups within pipeline integrity such as analysis, programs, materials and tech services. You know, this idea was first floated in May of 2009. Ultimately, it was approved and the final product was delivered by IT in July of 2010 and it's called Pipe Tracks.

Now, with the Marshall incident -- because I believe it was rolled out about 5 to 10 days before the incident, it actually wasn't rolled out to pipeline integrity until January of this year. And the driver behind that was, you know, the whole process of, you know, ILI analysis, you know, it's a large integrated process and it had a high potential for communication breakdown because a number of different groups actually touched that data throughout the process of, you know, getting it from the vendor and actually turning it into a dig program. So that program was designed to track ILI, basically, from the run planning stage right through until the dig package production.

We had a couple of other initiatives underway, as well. You know, in 2008 we developed a web-based tool called eDig and that provided near to real-time updates and tracking of all integrity-based excavations across the system and that system's used by field personnel, main line projects people and personnel and integrity to maintain progress and a detailed history and the NDE results for all digs.

MR. PIERZINA: I'm sorry, Steve. What was that called?

MR. CHATTRE: eDig.

MR. IRVING: It was called eDig, e-D-i-g.

MR. JOHNSON: And we'll most likely be looking at that during the course of the week when we get into some particulars, Brian.

MR. PIERZINA: Okay.

MR. IRVING: So then the last thing under data management and integrity -- or integration, I should say, was a pressure restriction SharePoint site and that site was created to become the single source of the truth, so to speak, for all pipeline integrity-related restrictions that would be issued to our facilities management group and the control center operations group. And that was set up to handle point-specific features, the pressure restrictions associated with those, as well as general station discharge pipeline restrictions that we might put on a whole line, for instance. Like, we have a number of those in place now, for instance, on Line 5, just as an example.

On the NDE side, work was underway to gather and organize the entire history of NDE reports into one location. And what we were trying to do there was list the pipe characteristics with the spatial and physical data. The data was to be integrated into a tool called Pipe Books, but work on that initiative was really in its early stages of development.

And then finally under NDE we did do a review, a comprehensive review of our NDE scope of work. This included the training of new NDE vendors, because we'd grown dependent on a really small number of companies and those companies had a small number of workers, and when we looked at what the volume of work was out there, we just needed to get more vendors up to speed with our NDE specifications. So we took initiatives to address, you know, that particular issue.

On the dig execution strategy side, in 2009 we developed a pilot program to complete -- well, it was 222 digs with our main line engineering group and core project team and that was completed at a cost of about $30 million. But what this pilot demonstrated to us was that it added project controls, cost certainty and schedule.

You know, through, you know, 2009 we were utilizing, you know, our field operations group to execute the digs and as we were seeing larger and larger programs beginning to surface, we just felt it was going to overwhelm them and so we decided to make a change, get the engineering group in that can provide us with better cost certainty and schedule, and the pilot did show that they could provide that. So we were in the process of setting up an engineering group primarily for the execution of our dig program.

Tool technologies, I guess, we identified a need to run new tools with a goal to provide better defect characterization on certain lines. And, you know, certainly specifically for corrosion, Enbridge had planned to run the new transverse MFL tool in Lines 10 and 17 to evaluate tool performance for unique features and selective seam corrosion. So we were looking at new technologies to try and help us, certainly, on the corrosion side, to try and better characterize some of these unique features that we were seeing on some of our lines.

Following -- again, on the tool technology side, in early 2010 or earlier in 2010 we had two failures on Line 2. You know, there was one in January of 2010 and then another one in April. They were both crack defects on Line 2. One resulted in a rupture. This was the one up near the border, Brian, you know, I guess within eyeshot of the Gretna Pump Station.

MR. PIERZINA: Yep.

MR. IRVING: And then the second one was at Deer River in Minnesota and it was just a small leaker but we decided, following those two failures, to run the Duo tool from GE. That's the new generation of ultrasonic crack technology. And we decided to run it in a number of different lines, as well as the cutout from the Deer River leaker. When we repaired that line and put it into -- back into service, we put a Flintco (ph.) clamp over it. So that feature was left in the line and eventually, though, it was cut out and replaced, you know, with new pipe. But when we run the Duo tool in the -- in a number of different lines, we did change the angle of the sonic signal coming out from the tool. We were looking to see if that was going to help us better characterize some of these defects that were -- we were seeing out on, you know, different lines that we had. And as it turned out when we did the pull through tests on the Deer River defect, we found that the angle -- the optimal angle was 45 degrees for that particular type of defect.

So we were looking at various options there with the Duo tool because the Duo tool, as the name implies, you can run -- with a single tool, you can run it in metal loss mode or in full crack mode or you can run it in both, and, you know, it's, I guess, a new tool available to us. And, certainly, once we become comfortable with it, if we can run it in both modes it'll actually cut down the number of tools that we have to insert in the line because you're basically getting two-for-one type of thing. But I don't think we've got there yet but I'm sure that will be on the -- integrity's plate to try and utilize that technology to its fullest extent.

On tool run frequency, you know, again following those failures on Line 2, I guess I had made the decision, but it wasn't implemented, because the decision that I made was just prior to Marshall and that was to run all of our technologies on a 3-year basis in tape coat lines. But, again, I just want to stress that that hadn't been implemented because we were hit with Marshall almost right away and I believe it was some time after that where maybe that became policy.

But I did want to talk, I guess, about Line 6B. We did have, you know, as a result of these tool runs, then, the rereads or I should say the reissues. We had scheduled the MFL and ultrasonics on a 2-year assessment window. It was actually scheduled, you know, following the 2009 runs to be done in 2011, and that was scheduled, really, as part of the longer-term replacement and repair strategy, you know, that we had for Line 6B, you know, that was in place, you know, prior to the rupture. You know, in fact, on Line 6B the crack tool was originally scheduled to run in November of 2009 and the run immediately before putting the tool in 6B, the tool was damaged in our Line 6A when it was run into a closed valve at Cottonwood Station.

That was the only tool of its kind and it had to be sent to Germany for repairs. It took about 7 months to repair the tool at the cost of, I think, a little over a million bucks. So when we got the tool back we put it in Line 6B and it -- the line failed when it was at an upstream station, unfortunately. So, yeah, we -- while the tool was in the line, and we just missed, I guess, the defect.

MR. PIERZINA: Steve, when you talked about the 2-year intervals, did you mean like 2-year ultrasonic and then 2 years later MFL then 2 years later ultrasonic, or --

MR. IRVING: No, we were planning to run -- after the 2009 ILI run in 6B we were planning to run both ultrasonic and MFL technology in Line 6B in 2011. So that would have been a 2-year interval. And that decision was made because we wanted to get a good look at the defects that were not repaired because our pipe replacement program at that time we were looking at potentially a 2012 end date. So we wanted to get a good handle on the defects that were in 6B, you know, prior to the replacement program so that we could go out and do repairs, as needed, on 6B. Of course, we didn't get there.

MR. NICHOLSON: The damaged tool was an ultrasonic tool?

MR. IRVING: Yes.

MR. NICHOLSON: Oh, there were two -- actually there were two pigs in the line, right? In 2010?

MR. PIERZINA: The cleaning --

MR. IRVING: Well, there --

MR. PIERZINA: -- the cleaning pig.

MR. NICHOLSON: Oh, that's right. One was --

MR. IRVING: Yeah.

MR. NICHOLSON: -- a cleaning pig.

MR. IRVING: I think, yeah, the other one would have been a cleaning pig.

MR. NICHOLSON: Okay.

MR. IRVING: So yeah, from the -- basically, from the -- late November 2009 right through the first half of 2010, the tool was being repaired in Germany at their ultrasonic center. We got it back and stuck it right in the line and it stayed there for 2 months.

MR. CHHATRE: Still your turn, Jay, to ask questions.

MR. IRVING: So I got maybe just a little more information on our crack program. You know, in 2007 we had three ruptures in our system. Two of them were integrity-related and one was construction-related on our Line 14. But what we did from the Line 14 rupture was we took some pipe out of that line and we conducted full-blown fatigue tests, and we picked a section of the line that had known crack defects in it, and what we did was we brought the pipe back to C-FER Technologies here in Edmonton and we ran full fatigue tests on.

And we basically, you know, would fill it with water, pressure it up, take the pressure off, pressure it up. This was done, I think, on 30-second cycles, so we very quickly, you know, got into the thousands of cycles. So we actually fatigued or cycled that pipe to failure and we used the results, actually, from that program to modify our crack program. And that -- those results ended up in us making determinations on our C and N factors for the Paris Law equation and we modified those accordingly.

The modification was such that it reduced our expected time to failure and we ended up -- because initially our crack programs were set at 10-year intervals. The result of those fatigue tests brought us down to 5-year intervals. So we feel that that was a significant program improvement as a result of a failure that we saw in Line 14.

MR. PIERZINA: When were those done?

MR. IRVING: Well, the failure on Line 14 occurred on January 1st and that was -- was it Rical (ph.) Road? I think is what we refer to it as?

MR. JOHNSON: Nope. That was Old Station.

MR. IRVING: Oh, that was the --

MR. JOHNSON: Rical Road was the sheet metal.

MR. IRVING: -- that was the sheet metal or the sheet piling incident. That's right it was another spot on Line 14. We -- those were done in later 2007. So sometime, I would say probably Q2, Q3 2007 those fatigue tests were done.

MR. PIERZINA: Okay. So, I guess, and maybe correct me if I'm wrong, I was under the understanding that your C and N values that Enbridge is using now are the API 579 recommended values; is that correct?

MR. IRVING: I believe so.

MR. PIERZINA: Okay.

MR. IRVING: We were using other values prior to that.

MR. PIERZINA: Okay. So that work that you did helped get you to using the API 579 recommended values?

MR. IRVING: That's right.

MR. PIERZINA: Okay.

MR. CHHATRE: Jay?

MR. JOHNSON: Were you interviewed by the Enbridge internal investigation team?

MR. IRVING: I was.

MR. JOHNSON: Okay. That's all I have. Thank you.

BY MR. CHHATRE:

Q. Just a few questions for you.

A. Sure.

Q. I guess earlier maybe -- who said that -- somebody said that, maybe Brian said that, that hydro was one of the options that integrity management group looked at, hydro testing.

A. It was a, I guess, a tool in our toolkit --

Q. Right.

A. -- that we looked at but I think, as Matthew probably described it, you know, we always found that the ILI results gave us the confidence, you know, that we had to, I guess, avoid a hydro test. You know, I think as everybody aware, depending on the, you know, the type of pipe manufacturer doing a hydro test, you know, could potentially activate, you know, some dormant manufacturing defects and, you know, that's one of the downsides of doing a hydro.

Again, the hydro is just a single point in time, you know, that gives you confidence at that point in time, but I guess, yeah, it's -- it was a tool that we probably did not utilize. We depended on the ILI results, our dig correlations and whatnot. I know they didn't get into it here but they certainly do a lot of analysis work on outliers. You know, they look at the unity plots. They look at everything that falls outside of their bandwidth that I believe they set at somewhere around 10 percent to see how the tool -- you know, if there's any tool bias in its call versus what we see in the field.

Q. I guess you answered my next question, but do you guys every use hydro in any of your lines? I guess the answer is no?

A. Well, in the last few years we have not used hydro as a tool to prove up integrity.

Q. Do you recall when was the last time you guys used it and, if so, on what line?

A. Well, we mentioned, you know, in 2006 -- now, this was used to reestablish a higher MOP and this was done after running an ILI and doing a dig program on Line 3 from Hardisty to Matiscol (ph.). You know, that was part of our expansion plans. And they determined that, you know, we needed a higher operating discharge pressure there so we went through a complete ILI and dig program and then did a hydro test, and we did a successful hydro test at the pressure that was aimed for, you know, by our facilities planning group.

Q. That was in 2007 for which line?

A. I believe it was 2006. It was Line 3 between Hardisty, Alberta and Matiscol. They're pump stations on Line 3 in eastern Alberta.

Q. And do you recall how long a section was tested?

A. I believe it was the entire segment and it would have been close to 40 miles --

Q. Station to station?

A. Yes.

Q. Station to station?

A. Station to station. But I'd like integrity to confirm that.

MR. JOHNSON: But other than that, other than new construction where the hydro is used as a baseline, I don't believe we used hydro testing as an integrity measure.

MR. IRVING: Well, we haven't for a number of years. Like, in the mid -- I know in the mid-'90s when we had a number of failures on Line 3 in Canada we did go back and reestablish MOPs by hydro test, but of course that was -- I should say that was precursed by, you know, doing some ILI runs and doing a dig program followed by a hydro test to confirm it. But, again, that was in the mid-'90s on Line 3.

MR. JOHNSON: And on Line 5.

MR. IRVING: Is that right?

MR. JOHNSON: Yes.

MR. IRVING: Okay.

BY MR. CHHATRE:

Q. And were there any failures during the hydro, do you recall? I know it's going way back --

A. You know, I was in another business unit at the time so I can't --

Q. Okay.

A. I don't know for sure. But Scott, actually -- probably between Scott and Matthew -- I think Scott actually worked on the --

MR. JOHNSON: Scott was out on that. Yeah.

MR. IRVING: He was on that. He'd be able to tell you.

MR. CHHATRE: Okay.

MR. JOHNSON: I think we've got about 5 minutes here for Steve if anyone's got any questions.

MR. CHHATRE: Okay. I got -- I'll ask real quick.

BY MR. CHHATRE:

Q. You mentioned a couple of failures on Line -- various lines. What do you guys, as a operator, do you look at those failures yourself or send out for analysis as to what caused the ruptures or just replace them?

A. Oh, no, we do a full blown metallurgical analysis, as well as an integrity program review on that line segment after every failure.

Q. And are the reports available on those?

A. Yes.

MR. CHHATRE: Do we have them, Matt?

MR. NICHOLSON: You're going to have to be more specific on which ones.

MR. JOHNSON: No, you don't.

MR. CHHATRE: Okay. I'd like to get those.

MR. NICHOLSON: Which failures?

MR. JOHNSON: Well, I mean, there would be -- are you talking about the Neche one, the Line 14 (indiscernible) one --

MR. NICHOLSON: Oh, I asked for the Neche -- oh, and the Norman Wells was the other one we were interested in.

MR. IRVING: Oh, from just this past year?

MR. NICHOLSON: Yeah, sounds like it.

MR. JOHNSON: So, I mean, you've got some, Ravi. I mean, we can get -- certainly, get more.

MR. NICHOLSON: Yeah. We've requested some. I guess you'd have to --

MR. CHHATRE: I just want to go back to the rupture and leak most recently that you mentioned. I think you mentioned four ruptures and leaks were mentioned.

MR. JOHNSON: The rupture at Neche?

MR. CHHATRE: One rupture, one leak on -- in one particular --

MR. JOHNSON: Okay. That was Neche --

MR. CHHATRE: Okay.

MR. JOHNSON: -- and Deer River.

MR. NICHOLSON: Um-hum. That was Deer River.

MR. JOHNSON: Line 2.

MR. CHHATRE: And there were three ruptures on Line 14.

MR. IRVING: Oh, no, three ruptures in 2007.

MR. CHHATRE: '7, right.

MR. IRVING: Right. And there was one on Line 3 in Canada just downstream of Glenavon Pump Station and then the other two were on Line 14.

MR. CHHATRE: Right.

MR. JOHNSON: But one was a rupture; the other one was third-party damage.

MR. NICHOLSON: I thought two were third-party damage; one was rupture.

MR. CHHATRE: No, I think one was.

MR. IRVING: No, just one was third-party damage.

MR. CHHATRE: Yeah, I'm not interested in third-party. I'm just only interested in --

MR. IRVING: That was the one at Rical Road that occurred in February of 2007. The rupture on Line 14 on January 1st was -- and we did a full-blown metallurgical analysis, was actually due to manufacturing defect.

BY MR. CHHATRE:

Q. And I guess my question on those was, any of those ruptures involve ERW pipe?

A. The Line 14, January 1 rupture was high-frequency ERW.

Q. It was high-frequency.

MR. JOHNSON: 1997 vintage, not pre-70.

MR. CHHATRE: Okay.

MR. IRVING: Yes, that's right. Well, maybe '98. It was '97 or '98.

MR. IRVING: '98 was -- '98 it went into service.

MR. IRVING: Oh, right. Yeah. You're right.

BY MR. CHHATRE:

Q. Now, you are talking about 6B replacement project. Are you still referring to 30-mile long segment or you are talking about anything more than that?

A. No, we have approval from our shippers to replace 75 miles of pipe now --

Q. Now. Okay.

A. -- on Line 6B.

Q. Okay.

A. And that includes the 50 miles downstream of Stockbridge and then the 5 miles downstream of the five upstream pump stations for a total of 75 miles.

Q. And does any of this leak repair history goes back -- is fed back to the risk management group?

A. Yes.

Q. Including the root --

A. The risk --

Q. -- cause?

A. Including what?

Q. Including the root cause of the ruptures?

MR. JOHNSON: Yes. Because it will go into the failure mode. So if it's pipe defect or if it was an operator error, things like that. That's one of the components that ORM will talk about Wednesday.

MR. CHHATRE: No, no. I was actually -- when you guys do the root cause of rupture does it -- you know, does that report find its way to the risk management group? Because they are the ones who are assigning values and --

MR. IRVING: They would be -- they would receive information that would tell them what the root cause was but I don't know that a copy of the report would be sent to them. However, it would be available to them to review through the --

BY MR. CHHATRE:

Q. But there's no process that requires that, you know, you have processing, okay, John Doe gets it and then CC will go to these different departments. I guess my question is, is the process there that says somehow the information does get to, in whatever shape or form, does get to the risk management?

A. The information gets to the risk management group. I'm not sure that they get the actual report but they -- one of the factors that went into, for instance, the index model was a failure history of Enbridge. So that was a factor that was taken into account in the index model.

Q. Okay. I know I have one more question but if I don't find it in the next 30 seconds, I'll pass.

MR. JOHNSON: Ten, 9 --

MR. CHHATRE: No, I can't locate it. I know I wrote it down someplace. I can always call you or send you an e-mail.

MR. IRVING: Yeah, you can send me an e-mail. I'd be happy to --

MR. NICHOLSON: He'll be back Friday.

MR. IRVING: -- ask if --

MR. CHHATRE: Oh, you're back Friday. Good.

MR. IRVING: Yeah. I'm back Friday --

MR. NICHOLSON: He took all week.

MR. CHHATRE: Oh.

MR. IRVING: -- Friday afternoon.

MR. CHHATRE: I want you to know that I finished in 5 minutes before.

MR. JOHNSON: We're doing fine.

MR. CHHATRE: I have no more questions. Thanks.

MR. NICHOLSON: Matt?

MR. FOX: None from me.

MR. NICHOLSON: Brian?

MR. PIERZINA: I'm good.

MR. NICHOLSON: Really? Okay. I think at this point we'll conclude the interview. We'll stop the recorders.

MR. CHHATRE: Off the record.

MR. NICHOLSON: 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 Interview of Stephen Irving
DOCKET NUMBER:	DCA10MP007
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.

____
Beverly A. Lano
Transcriber