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: LENARD KRISSA

Enbridge Headquarters
Edmonton, Alberta
Canada

Tuesday,
December 6, 2011

The above-captioned matter convened, pursuant to notice.

BEFORE: MATTHEW NICHOLSON
Investigator-in-Charge

APPEARANCES:

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

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

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

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

I N D E X

I N T E R V I E W

MR. NICHOLSON: This is NTSB pipeline case number DCA10MP007, 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 Tuesday, December 6th, 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, Len, please state your full name with spelling, employer name, and job title.

MR. KRISSA: Full name Len Krissa, K-r-i-s-s-a, L-e-n-a-r-d. Position is team lead in the analysis group. And any other information required?

MR. NICHOLSON: Actually, if you'll give us a contact phone number and e-mail address, that would be great.

MR. KRISSA: That would be [redacted] My cell is [redacted]; fax number [redacted].

MR. NICHOLSON: Did we get an e-mail?

MR. KRISSA: [redacted]

MR. NICHOLSON: Okay. Len, 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 no one at all. If you would, please indicate whom you have chosen to be present with you during this interview.

MR. KRISSA: No one at all.

MR. NICHOLSON: Okay. We'll go around the room, have each person introduce themselves for the record. I'll begin. Matthew Nicholson, M-a-t-t-h-e-w, N-i-c-h-o-l-s-o-n. I'm the NTSB IIC. My phone number is [redacted]. My e-mail is [redacted].

MR. FOX: Matt Fox, NTSB Materials Lab, [redacted]. E-mail is [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 PHMSA [redacted] My e-mail is [redacted] and my phone number is [redacted].

MR. CHHATRE: Ravindra Chhatre. I'm Integrity Management Group chair, NTSB. My e-mail is ravindra.chhatre. That's [redacted] Phone: [redacted]

INTERVIEW OF LENARD KRISSA

BY MR. NICHOLSON:

Q. Okay. Len, to start with, why don't you go ahead and give us a little bit about your background, when you started with Enbridge, what positions you held within Enbridge and take us up from maybe your start, maybe -- include your educational background up until now.

A. I graduated from the University of Alberta in 1993 with a petroleum engineering degree, co-op program. Significant designations would be a NACE Level 4 CP specialist and my current title with Enbridge is the only position I've held with the company starting in November 2009 to present.

Q. And can you describe the duties you perform under this title?

A. I provide support and QA/QC under the core processes of the analysis group. I also liaison with the operations group to integrate cathodic protection information and then correlate it with in-line inspection data. I also provide support on spacial information. I've got a strong background in GPS, so any surface information to integrate that and correlate -- do girth weld translations to find a common positioning between different data sets.

Q. Oh, okay. So part of your responsibilities are overlaying or integrating?

A. I do a variety of things, a lot of support between the different departments. And, like I said, my primary is to support and assist in the core processes. I'm the team lead of the analysis group so any of the in-line inspection programs, I'll review for the most part the PI listings, which I believe Ryan reviewed with you previously. So I'll review the dig recommendations before the dig packages are actually submitted and executed. I'll review those for safe excavating pressures, safe operating pressures and also review the rationale behind the dig selection.

Q. So going back to CP -- that's why we brought you in here. Explain a little more about your involvement with the cathodic protection. I guess you interface with the regions; is that --

A. Yeah, that's correct. The primary reason I was brought on by Enbridge was to establish a stronger conduit between the integrity group and the operations group that are responsible for the CP management program. So it was realized that integrity was primarily based on in-line inspection and CP is a lot of surface work, and they're both critical to the integrity program so they wanted to establish a stronger connection between the two data sets.

Q. Can you elaborate a little? I don't know what -- a stronger connection how?

A. In terms of integrating the two data sets, correlating specific CP information with in-line corrosion data.

Q. And how does -- what do you do to create that connection? Is this a database? How does it manifest itself out?

A. The region supplies an annual CP exception report to me. I then review the exceptions and determine whether they could potentially impact corrosion rates. And then from that we'll forward a recommendation to the subject matter lead for that particular line segment and do a review to determine if possibly the corrosion within that area, if there is any corrosion detected from the in-line, maybe attributed to a CP factor.

Q. Okay. So the exception report is anywhere the CP isn't meeting the 850 millivolt?

A. We apply primarily 850 and beyond that we'll also consider 100 millivolt polarization shift as a secondary criteria, but our primary criteria is to achieve 850, off.

Q. So if you receive a report that says there's an exception on a segment, what do you do with that? How do you determine whether that's impacting corrosion?

A. It depends on the exception. Like the region will -- they'll provide an exception. Some of the exceptions could include a damaged test station. Well, we wouldn't consider that as an immediate threat to the pipeline from an integrity -- like our definition of integrity. So that really wouldn't be a relevant exception from our perspective. However, if it was reported that a rectifier was down for an extended period of time, we would then take that into account and highlight it in my report that gets distributed to the SMLs within the integrity group to do a specific review within that region.

Q. Do you have any involvement on the setting of potential levels, the rectifier outputs?

A. The outputs?

Q. Uh-huh.

A. No, that's under the jurisdiction of the regional CP specialist or technician.

Q. Okay. Ravi, do you want to continue?

BY MR. CHHATRE:

Q. What is the optimum level of CP that you would consider normal for the operation of the pipeline?

A. In excess of 850 off.

Q. Okay.

A. More negative.

Q. Than 850 off, right?

A. Correct.

Q. The reason I ask that, because I think that I -- I think my memory is reasonably good. But I saw some readings with like 1600 millivolts on 6B, I believe, maybe some different line, and I'm just asking does that qualify for an exception report?

A. An excessive polarization?

Q. Correct.

A. In some -- we're considering that an exception. It's not policy at the moment, but I'm currently reviewing the design standards and we are considering ceiling limits for CP, rather than just a minimum. We're considering the maximum. More so on the X70 steels. It's the newer construction where it's getting a little more attention. And we're finding a difficult balance because we certainly want to respect the 850 criteria as the foremost priority, but on the same note, we don't want to be susceptible to hydrogen evolution where we could potentially damage our coatings as well and cause some damage to our pipelines. But, like I say, it's a fairly delicate balance when we have a variety of vintages of pipelines with different coatings and all operating under a common CP system. So you have to find that happy medium where you're not running one line and not meeting 850, but on the same note not running an excess of -- 1600 is certainly where we would consider it to be excessive. We're actually considering a 12- to 1500, and that's not established at that time, but this is the ranges that we are keeping in mind for a ceiling.

Q. Why would you go as high as 1500 millivolts?

A. It's under review right now and it requires feedback and opinion from all the regional stakeholders, the various CP, the regional people. So I need to get an appreciation of what their operational tolerances are and how flexible they are. So right now we want to -- we're certainly recognizing that ceiling limit, but we haven't defined --

Q. Oh, okay.

A. -- an absolute value for it.

Q. And who will you be talking to to kind of come up with some kind of a consensus?

A. All 10 of the operation CP regional personnel.

Q. Meaning all 10 CP regions --

A. Yeah. We go into regions and perhaps -- I've got a hard copy of the map so -- actually, I could probably bring it up here.

Q. But all the corrosion technicians who monitor the CP level are the people who you're talking to?

A. Precisely.

Q. And what are their titles? You call them CP technicians, engineers, what?

A. Their -- depends on their background. Some of them are designated as CP specialists.

Q. Okay.

A. Others are CP technologists and some are titled with a CP technician, but their responsibility is all essentially the same.

Q. So is the CP technician considered lower than a technologist than a specialist in terms of whatever the reason for the designation is, or --

A. Not in terms of responsibility.

Q. No, but, I mean, so why three different -- are they based on educational background, NACE certification, or something like that?

A. Kimberly Harris would be able to --

Q. That's fine.

A. -- confirm that.

Q. Okay.

A. I'm not responsible for the titles that they hold.

Q. And what is your background before you came to Enbridge?

A. I was on the service side of things since -- I was actually introduced as a co-op student to the CP industry in 1990 and I've worked directly with CP until '99. From '99 to 2004, I was involved in primarily over-the-line surveys, coating surveys, water core surveys, close interval CP, kind of the more-detailed evaluations. 2004, I consulted independently. In 2005, I started up my own cathodic protection service company with materials provision with three other partners.

Q. Okay.

A. And then as I mentioned before, in 2009 is when I left that venture to join Enbridge.

Q. Was that after the Marshall accident? Do you remember? When did you join --

A. I joined before Marshall.

Q. Which you -- okay. You said 2009, I'm sorry.

A. Yes.

Q. You said before Marshall. Have you looked at since joining Enbridge, have you looked at their CP program in general? Or that is not your responsibility?

A. I'm very familiar with the corrosion control guidelines, which is managed through the operations group, and integrity does have its own cathodic protection program --

Q. Okay.

A. -- where we basically outline what the information is and how to utilize it, and also provide feedback to the region.

Q. And is that a written document? When you say integrity has their own CP program?

A. It is a written document, yes.
Q. And what is that called?
MR. JOHNSON: That would be in your -- well, unless you have one, otherwise, it's in that list we gave you.
MR. NICHOLSON: Um-hum. It's in that index you gave us?
BY MR. CHHATRE:
Q. Okay. So it could be there. Okay.
A. It's linked through the IMS.
Q. Okay.
A. It should be shown there.
Q. Okay, great. With all your CP background, and it looks like you have an extensive background in CP, what are your thoughts on (indiscernible) protection? What protection level would be considered adequate based on your experience? 850 is NACE specification --
A. Yeah, in some cases 950 when there's bacteria --
Q. Yes.
A. -- or certain soil conditions, moving water. So in terms of what's adequate, 850 is the absolute minimum, but there's always case-specifics where you need to consider whether or not you need to adjust that criteria accordingly in terms of temperature. There's many considerations, but when you see 850 that is the industry-recognized criteria that we utilize.
Q. Have you noticed high CP potentials since you joined with Enbridge? And if you did, did that raise a concern?

A. In terms -- I wouldn't consider them excessively elevated at this time. From what the other information that we have, there's no indication that, from in-line inspection results, that what are relatively high within the Enbridge system is causing anything detrimental to our pipeline. I've been in instances where we've been applying an excess 4 volts on just to achieve and still not accomplishing, you know, negative 850 polarization. So, once again, it depends on the situation and the location before we can generalize.

Q. Did you have a chance to look at the CP reading, the different lines, especially 6B?

A. I have reviewed 6B, yeah, and I believe that it's in an acceptable range of protection.

Q. And what is the protection range you have seen on 6B? Do you recall?

A. It's typically, on average, 1100 off.

Q. Okay. Did you see anything close to 1600?

A. Not that I'm aware of.

Q. Okay.

BY MR. NICHOLSON:

Q. Well, where have you looked on 6B? We should be more specific. We're speaking of the rupture sight there near Marshall. Have you looked at that? Is that data set you're --

A. Yeah, I've reviewed the close interval data for it.

Q. Okay. Because I'm looking at one dated, I think it's

August of 2010, the first of August.
A. That's a follow-up CIS.
Q. Okay. And I'm showing 1800 on and 1450 off?
A. Yeah, which would be below 1600.
Q. Is that what you were seeing?
A. That's what Ravi commented on.
Q. But I thought you said 11- -- I thought I heard a number of 1100.
A. Oh, yeah. I said on average.
Q. Well, that's why I want to be specific with this section.
A. Yeah, it should be -- oh, within the information that I reviewed in immediate proximity of the failure site is certainly in the polarized 1400 off range.
MR. CHHATRE: And so --
MR. NICHOLSON: Go ahead. I'm sorry.
MR. CHHATRE: No, go ahead. I'm sorry.
BY MR. NICHOLSON:
Q. You mentioned there could be extenuating factors in some cases and I wondered if any of those extenuating factors would have been applicable here for them to be running it so high? Is there a reason? It's a wet environment.
A. Not that I'm aware of.
Q. Distance between stations. You mentioned temperature could be a driving factor.

A. In establishing criteria, but as I mentioned before, it's the responsibility of that CP tech within that region to establish his levels and report on the exceptions accordingly. And there were no exceptions that were reported within this region.

Q. Okay. Because there's no ceiling in place, so there would be no exception, right?

A. Correct. And even with my historic background, I don't foresee these potentials as being detrimental.

Q. Okay. Even to what you were talking about earlier with the disbondment, the hydrogen evolution, you don't see that as an issue at this level, 1450?

A. I don't believe so.

Q. Okay.

MR. NICHOLSON: I'm sorry, Ravi. Go ahead.

MR. CHHATRE: No, no, no, go ahead. You're done?

MR. NICHOLSON: I'm done.

MR. CHHATRE: Okay.

BY MR. CHHATRE:

Q. So did you have a chance to discuss this potentials on the ruptured pipe segment with the -- your regional technicians, technician specialists?

A. Yeah, I discussed the information and there was nothing exceptional to discuss.

Q. So what potential levels would you expect hydrogen evolution based on the Coby (ph.) diagram, or --

A. I'd have to reference that. It depends on proximity and there's a number of factors I'd have to --

Q. On Coby diagram? Coby diagram is thermodynamics function?

A. It is.

Q. So, I guess I'm referring to is have you looked at that this potential level may not be high, may not have -- on the pipe the coating is so damaged that it is -- that it cannot be anymore detrimental? I'm just trying to find out have you looked at this potential level and said what potential level you would expect a hydrogen evolution that cathode your pipe surface? I guess if you haven't, will that be a part of your discussion with the CP technicians?

A. It certainly will be part of the consideration. Hydrogen evolution is one of the main factors in establishing a ceiling limit.

Q. Have you seen that high potentials on other lines on Enbridge? You mentioned something about the newer lines have high potential also?

A. That's where we're -- I think, based on documentation, it's the X70 steels, the higher strength steels that we're -- I think they would be more vulnerable.

Q. And those steel pipes, when were they installed and do you know the approximate age on those pipelines?

A. The focus would be probably from 2000 onward.
Q. Okay. And do you know the coating on those pipes?
A. Fusion bond epoxy and HPCC for the most part.
Q. Any of the older lines, have you had a chance to look at this potential levels, especially the tape coating?
A. Sorry, could you repeat that?
Q. Any of the Enbridge's lines which are older, with the tape coating, have you seen the same level of CP? Like 1100 off, 1600 on, kind of range. Not exactly same numbers, but --
A. Depends on where you're looking at the potentials, whether you're in close proximity to a rectifier or farther away. It's dependent on the location.
Q. But you have seen these ranges?
A. I've reviewed it, but I'm not involved with that --
Q. Right.
A. -- level of detail with the CP. I'm -- like I mentioned before, it's the exceptions that I pay attention to and whether or not there's something unusual from our in-line data that could trigger me to inquire about a CP factor, like a high CGR growth from the in-line inspection information would be the other direction.
Q. And CGR growth meaning?
A. Corrosion growth rate.
Q. Oh, okay. And that will be for the lower side of the potential or higher than --

A. That's where we would look into what the actual potentials are at that location. If we've determined that there is an unusually high corrosion growth rate, CGR, based on in-line inspection results, we'll follow up with the CP tech to get the historic actual values within immediate proximity of that location.

Q. Are you the operations services CP specialist or -- I'm trying to find out who that person would be? Is that you, operations services? I was told --

A. No, I'm not. I'm in pipeline integrity.

Q. Okay. So do you interact with that person, operations services?

A. Absolutely. That would be Kimberly Harris.

Q. Okay. And that interaction is for what?

A. In April 2010, we had our very first O3C committee meeting. And that's Operations Corrosion Control Committee.

Q. Okay. April 2010?

A. Correct. That was our very first face-to-face.

Q. Okay.

A. And Kimberly is the -- she chairs this committee.

Q. Okay.

A. And it comprises of all the regional personnel, along with some pipeline integrity representation.

Q. Okay.

A. This is kind of small, but this is kind of how the regions are divided.

Q. Okay. Uh-huh.

A. So this is our system, and we have a regional CP representative for Western Canada --

Q. Okay.

A. -- Central Canada --

Q. Okay.

A. -- our gathering system in Saskatchewan, the gathering system North Dakota. Then we have Western Superior, Eastern Superior, Chicago, Cushing and Eastern Canada. So that's the boundaries of how the CP regions are divided.

Q. There are nine, I think. And each one has two CP people?

A. There can be assistants in some areas. In some of the larger areas, they have assistants. Right now Cushing and Chicago have some assistants.

MR. JOHNSON: In Superior, Cushing and Chicago Region, they all have two now.

MR. KRISSA: Superior, East and West?

MR. JOHNSON: Well, it's Superior Region. So you have John Bissell and Gordie Jensen (ph.).

MR. KRISSA: Yeah. But they have -- they got the subdivision --

MR. JOHNSON: Big areas.

MR. KRISSA: -- of East and West. That's represented here, Jay, by green and red.

MR. NICHOLSON: Yeah.

MR. CHHATRE: Okay. That's all I have. I may come back, but right now I'll pass it on to Brian.

MR. KRISSA: So this is actually the O3C site that we do our information sharing through just to centralize the information because we're two different departments and we needed a repository where we could interact the two data sets.

BY MR. CHHATRE:

Q. And this OCC Committee is an internal to Enbridge, right?

A. Correct.

Q. And besides Kimberly and these regional folks, who else is involved with that?

MR. JOHNSON: Actually, if you enlarged it and go over to the right you can see all the members on there.

MR. KRISSA: Oh, this isn't a full list, though, Jay. This is just who contributed the file.

But Kimberly chairs it and Nancy is the Cushing rep. Barry is the Central Canadian. Myself.

MR. NICHOLSON: What's the goal of the committee? Is it going to disband at some point? Is it short term, long term?

MR. KRISSA: I don't believe there's any intention of it disbanding. We want to continue improving our processes and leveraging both data sets to both sides' benefit.

MR. CHHATRE: The question, I guess, was what is the objective of the committee?

MR. KRISSA: The first, improve the channel between --

MR. JOHNSON: Actually, there is a, if you will, a mandate, you know, within the website that talks about, you know, what the committee does.

MR. NICHOLSON: Well, let's hear Len.

MR. CHHATRE: Yeah.

MR. JOHNSON: Okay.

MR. CHHATRE: I mean, since he's involved in it.

MR. KRISSA: The intent of the committee was to improve the exchange of information between the two groups because they were both responsible for an important data set that's related to pipeline integrity, yet there was segregation because in-line inspection information resided primarily here and was managed here, whereas the cathodic was very regionally dependent. And there was a lot of actual inconsistency between region to region. So what we're attempting to do is standardize the processes and the data formats so that we can use it in a form to maximize its value.

BY MR. CHHATRE:

Q. And, of course, being a common, I guess, storage place, everybody has access to it, being online, right?

A. The committee members, correct.

Q. Okay. And what inconsistencies would be resolved with the group effort, if I may?

A. Right now the regional -- this is -- it's really not -- I shouldn't be at liberty to say, but the region is involved -- like, just an example of some committee activities, the region is working on standardizing tank designs because there was some differences from one area to another. The overall intent is to unify the information and to establish standards.

We're utilizing a CP DM database with that standardized format. I know now what type of information to expect and the same -- you know, it's consistency. And once we have consistency of the data, then I can start establishing and producing some processes where it's a -- you know, where you have a step-wise process and you can use it universally throughout the system rather than dealing with each region specifically.

Q. That makes sense.

A. So going back here, membership, these are the various stakeholders from a department perspective. So these are who the committee recognized.

Q. And how often do you guys meet?

A. This past year, we met twice in person, and the intent is to be in communication formally every quarter.

Q. Okay.

A. So we have a minimum --

Q. In like a conference call?

A. Conference call and a minimum of one face-to-face, which is for the better part of a week.

Q. So, one face-to-face plus three phone meetings?

A. Yeah, and that's outlined right here.

Q. Yeah.

MR. NICHOLSON: Are there minutes produced from those meetings?

MR. KRISSA: There are.

BY MR. CHHATRE:

Q. Do you guys discuss the CP levels, having a uniform CP program, that kind of -- is that part of --

A. That's part of the discussion. Exactly. That would be an example of what's addressed at these meetings.

Q. Now, being a CP, I guess group, do you guys have any input into the coatings being selected for the newer pipelines or replacement pipelines?

A. Pipeline integrity has a say, but that's outside of my area of expertise.

Q. No, I mean as a committee, because this is going to be a --

A. Oh, coatings are always a discussion, sure.

Q. Okay. But does the pipeline integrity ask your -- the committee's input in terms of if we are building a pipeline so many miles, what kind of coating the committee recommends? If the goal is having a uniform system, what kind of CP level --

A. On a project-specific basis, the region and integrity are involved.

Q. Okay. But do they seek input of this committee? Do you know if the input of this committee is sought in the newer --

A. Not in the overall -- it depends on which region the project is taking place in.

Q. Okay.

A. And that representative is directly involved in the particulars and design specifications.

Q. And he's in your committee, so you --

A. And he is within the committee.

Q. Okay. Was the Marshall incident and coating and CP ever discussed in your committee?

A. Marshall was never really formally addressed at the committee to date. We're a relatively new committee so we're focused on the structure and we've got -- we're still establishing the foundation of it, and for us to -- Marshall removed a lot of people for a period of time and now we're focusing on generalizing, you know, and going back to overall what this committee is intended for and not specific to Marshall itself. It's certainly not a reactionary measure to Marshall. We can demonstrate the intent of this committee happened well before Marshall.

Q. Right. No, I never -- I didn't --

A. Yeah, that was not -- yeah, that -- if you're saying that the intent of this committee is a result of Marshall, that's not the case.

Q. No, no, no. Had they discussed the Marshall incident with coating problem and the CP level? Since there was corrosion on the external side --

A. There's always those discussions informally, and that's what's healthy about the face-to-face because there's all the people with common interests and these things are discussed throughout that week that we get the opportunity to get together.

Q. Okay.

BY MR. PIERZINA:

Q. So do you discuss -- and this is Brian Pierzina. Do you discuss stray current issues amongst the group?

A. Stray current interference, yeah. That's a topic of -- certainly. And when I first came on board, I spoke with Jerry DeWitt and received a listing of all the foreign crossings associated with 6B.

Q. Okay.

A. Just to review or correlate that against our in-line to see if there is the possibility of stray current. And I'm actually -- just recently took the co-chair for interference problems, the TEG 262X with NACE. So stray current interference is always a topic of interest within the committee.

Q. And is that something that's dealt with consistently amongst the regions?

A. In the process of.

Q. In the process of doing it?

A. Yeah.

Q. Okay.

A. We are certainly -- this committee's in its infantile stage so to accomplish all of these issues within a one-year period just -- we have to prioritize and it's not that we're not going to address stray current formally; it is being addressed throughout the regions but, as I say, I'm really not at liberty to say how each region manages their stray current program at a regional level.

Q. And is where the responsibility falls?

A. Within the regions? Certainly. Yeah.

Q. With the region CP techs?

A. Yes. Where I would be directly involved in a stray current issue is if one of our SMLs, subject matter leads, approached me and gave me an example within a piece of logged in-line inspection data and said, holy smokes, we have some unusual corrosion growth rate here, accelerated corrosion; there has to be an external mechanism that's driving this; this is outside of our typical rates. So from that, we'll consider some of your typical causes of accelerated corrosion, whether it be -- AC is always on the radar now for our newer construction lines. With the fantastic coating efficiency that you're seeing with the newer generation pipelines, AC is always one of the top contenders as a possibility or an explanation for an accelerated corrosion growth rate. And the other one traditionally is stray current, whether or not there's a foreign facility nearby where you're getting some detrimental influence.

Q. So can the process work the other way, like we have stray current, maybe we should run an ILI, you know, or move up the --

A. That can certainly expedite the inspection interval. And that comes from the exception reporting, as I mentioned earlier. If that's addressed as a recent concern, from that, whether -- depends on the situation. Everything's going to be case-specific, but nothing's really off the table at that point. And maybe we wouldn't even wait for an inspection. Maybe we would issue a dig at that location to do a direct visual confirmation of the extent of damage. If it's speculated or reasonable concern that, you know, substantial damage did occur within a short period of time, that could expedite an excavation.

Q. Okay. Can you think of examples where that's happened?

A. There was one case from where there was AC accelerated excavations where we were aware, and then once we did some follow-up testing -- we were aware of an AC threat, did some follow-up testing and expedited the excavations and also, subsequently, the installation of an AC mitigation system along the line.

Q. Okay. Getting back to the -- you had the survey of line 6B that was done, the on/off survey. Are you familiar with how that -- I guess, I'm not familiar with where the rectifiers are, which ones may have been interrupted for that survey. Are you familiar with that at all?

A. You would have to confirm that with the Chicago Region CP tech.

Q. So when you looked at it, you just -- you didn't actually look at how they did what they did, just the results of what they did; is that right?

A. Yeah. That's outside of my responsibility to dictate. I don't have that level of detail on the CP system.

Q. Sure.

A. Right now -- and it's improving. We're moving towards RMU installation throughout the system, and that's allowing us to be more accessible to this type of data remotely, and giving us a higher density of operational information and history, and also eliminating a lot of the problems that, in the past, dealing with manual installation of interruptions. We can interrogate these systems and you're alerted whether or not there's been one rectifier that's no longer interrupting and giving you erroneous off potentials. So the system -- remote monitoring has improved the process substantially in terms of the quality of information, the quantity of information and also reacting to when there is a rectifier that experiences any down time.

Q. So as far as stray current today, in your opinion, is it dealt with consistently by the regions in the same manner or do they each tend deal with it their own certain way?

A. To the level I can speak to is that I know they address, they all address stray current. Exactly the differences, I cannot say. If there any differences.

Q. And so all the corrosion technicians, do they report up to the same person or do they report up within the region?

A. Intermediately through the region and then up to -- and then Kimberly essentially oversees and governs the overall system-wide program.

Q. Okay. Thanks.

BY MR. NICHOLSON:

Q. Just a follow-up. You mentioned the fact that you guys were looking -- your group was looking at a ceiling limit for protection, cathodic protection?

A. Yep. It's under consideration.

Q. I didn't hear what prompted that? Why?

A. Recent industry recognition.

Q. Recognition that -- what? Recognition of there being a --

A. No --

Q. -- problem with too high a level, or --

A. The potential for coating damage that possibly can result. There's a lot of information out there, but at the same point we're not real conclusive to exactly what that threshold is. We're, like I said, we're looking at it and so far within our system, there's no evidence indicating that relative to what's high within our system has caused any problems.

Q. So it wasn't driven by some instance within Enbridge? It's coming from industry research or papers you've read or something?

A. Yeah, external sources.

Q. Okay.

A. It hasn't been driven by an incident or something specific within the company, like an incident where there's been evidence of a, you know, potential failure because of excessive CP. There's been nothing like that that's driven the consideration.

MR. PIERZINA: Okay. That's all I've got. Ravi?

BY MR. CHHATRE:

Q. Just a couple of follow-up questions, and I'll just follow one with Brian here. That AC incident you said caused the alarm, AC corrosion in the region, what was it? I mean, how did the regional folks know that they have a corrosion issue because of AC?

A. One of our --

Q. What (indiscernible)?

A. As of 2010, we've put the recommendation in to acquire AC potentials in conjunction with the annual adjustive CP survey, and we're doing an inventory of all co-locations. So we're in the midst of developing a formalized AC program, AC corrosion program, where we want to identify pipelines that are particularly very vulnerable to AC corrosion and establish the locations where they would be susceptible. And as I mentioned, within the annual adjustive CP survey, AC pipe to soils are taken. And it was through the test point AC pipe to soil that we were aware that there was excessive levels of AC.

And we're no longer using -- prior to -- historically, it's always been the 15-volt as the magic number, but that's driven from a safety perspective. We've come to understand that you can have AC accelerated corrosion at voltages much less than 15. So through remotes calibrated coupons, that's how we're establishing whether or not we have effective mitigation from our -- with our AC mitigation systems.

Q. Now, do you get involved in the dig packages and when the pipe is exposed to look at the coatings to see if there is a CP issue at all?

A. The actual dig packages?

Q. Yeah. Well, after the dig package, when the process starts and after the pipe is exposed?

A. Yes.

Q. Do you get involved in any way to look at the pipe to see if it's a CP issue at all, either to rule in or rule out?

A. The pipe to soil is not on a consistent basis, no.

Q. Well, I mean, do you at least get to look at the pipe to see if there is coating damage or there is a corrosion issue?

A. I do not have opportunity to review every dig that we complete within the company.

Q. Okay. Do you at least do a few or (indiscernible) --

A. Yeah, the unusual cases. If there's something out of the ordinary in terms of the morphology of the corrosion, then certainly. And that's -- I got involved with one of the AC ones because there was evidence of heat damage around the coating, which would also somewhat allude to AC corrosion.

Q. And where was that?

A. That was on Line 13.

Q. But somebody has to request you to come and take a look? You couldn't on your own decide, based on the package, that well maybe I should go and look at it because there are corrosion indications?

A. As I mentioned, there's hundreds of packages issued. I just do not have opportunity to review each one on an individual basis. It's got to be something exceptional before I'll get involved with it.

Q. And who makes that decision? Who decides if something's exceptional for you to get involved?

A. The SML is when I usually get --

Q. And who -- what is SML?

A. A subject matter lead.

Q. Oh, okay.

MR. JOHNSON: Would that be Oscar?

MR. KRISSA: Yes.

MR. JOHNSON: Okay. Because there's a potential we'll be talking to Oscar, so --

MR. CHHATRE: Okay. Thank you so much for your time.

MR. KRISSA: Thank you.

MR. NICHOLSON: Oh, well, let's see. Do you have anything else, Brian?

MR. PIERZINA: No.

BY MR. NICHOLSON:

Q. Brian had asked you earlier, Len, about the rectifiers on the readings that were taken at Marshall post-accident. They did a rectifier on/rectifier off reading. How many rectifiers do they need to take off-line to do an accurate rectifier off? I mean, I see -- it looks like they took four of them off-line to do that, that reading.

A. It depends on the area of influence.

Q. And how do you determine that?

A. I don't personally determine that within Enbridge, but until you have a neglible change in your off reading, you essentially --

Q. Oh, okay.

A. -- keep going and interrupting until once you turn your -- the extremity off and you're no longer really impacting your reading at the location of interest.

Q. Okay. I see. Yeah, a steady state, so to speak, just kind of flat-lined. Yeah, it looks like they went roughly 22 miles upstream and 13 miles downstream of the accident site, taking rectifiers off.

MR. JOHNSON: Kimberly may be able to answer that. Prior to taking the role she's in, she was the CP tech in the Chicago Region.

MR. NICHOLSON: Okay.

MR. JOHNSON: So she probably knows that area.

BY MR. NICHOLSON:

Q. Okay. And then we were talking about stray -- I thought I heard a talk about stray current corrosion. Is that something you deal with, stray current corrosion, you look for?

A. Not on a daily basis. If there's something case-specific that involves stray current and it requires some technical support, I'm certainly there, if a regional CP tech calls me and has some questions, but it's not part of my day-to-day duties.

Q. How would you see that? You would see it in your pipe to soils, the stray current? Or you would see it, as you indicated, through the corrosion --

A. Or it can be detected through a CIS, a close interval survey.

Q. Okay. Right.

A. And the other thing is it can also -- any new construction, notification of a new facility crossing the line.

Q. So I'm just trying to picture -- what would that look

like then on a close interval survey? Just be a spike, or --
A. An abnormal depression. In some areas, there'll be a -- could be an area of pick up and then an area of discharge.
Q. Okay. Are there any other methods employed other than just pipe to soil readings? This might not be your -- for you, but do they do any other surveys to determine coating disbondment, or --
A. We're undergoing an inaugural run with the CP CM tool, which is an in-line inspection tool specifically geared to detecting stray current protection levels and also, not directly, can possibly highlight areas of disbonded coating. Because from the CP tool's perspective -- it's essentially a moving shunt and disbonded coating from its perspective is going to show up as good coating. But if you overlay that against a corrosion log and you have corrosion there, then you can come to the conclusion that you have disbondment in there.
And it's also a pretty neat tool because it's all got an AC channel so you can monitor areas of AC as well.
Q. And it's called --
A. So that's something that's under consideration. And depending the outcome of the results with this run, we may end up considering this as being part of our routine testings to -- who know, maybe it may even be more beneficial to run the in-line CP tool than doing a conventional CIS.
Q. Okay. It's called CP CM; is that what --

A. Yeah, it's a Baker-Hughes technology.
Q. Oh, okay.
A. And it was actually -- I believe it was an R&D project done in conjunction with PHMSA.

MR. NICHOLSON: Okay. Thanks Len.

MR. KRISSA: No problem.

MR. CHHATRE: Thanks again.

MR. KRISSA: Thank you.

MR. NICHOLSON: Okay. This concludes the interview.

(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 Lenard Krissa

DOCKET NUMBER: DCA10MP007

PLACE: Edmonton, Alberta, Canada

DATE: December 6, 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.

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Vanita Tildon
Transcriber