

Extracted from:
TESTIMONY OF LAURA KENNETT
MPUC DOCKET NOS. PL9/CN-14-916
January 31, 2017

What is an integrity threat?

An integrity threat is any active or potential time-dependent damage that could cause a pipeline to leak or rupture. The four main categories of integrity threats are:

- metal loss (often resulting from corrosion);
- Cracking;
- deformation and strain;
- facility-related threats.

Enbridge uses high-resolution ILI tools that monitor integrity from the inside out using imaging technologies, such as ultrasound and magnetic resonance imaging (“MRI”). The ILI tools are developed and owned by third-party companies, who run these tools on many companies’ pipelines and gather information from across the industry. These third parties are then able to use the industry data to drive further tool improvements. ILI tools detect pipeline anomalies, which include physical objects, imperfections, and defects. Anomalies are then characterized, sized, and assessed. Anomalies that are an integrity threat are managed in accordance with the integrity management program. This is further detailed in Section 3.4.1 of the Certificate of Need Application

How does Enbridge monitor the condition of its pipelines?

In order to effectively monitor the condition of its pipelines, Enbridge invests significant resources every year in management systems and technologies to keep the pipeline system safe, including:

- the highest resolution ILI tools available;
- internal pipe sampling to check for the presence of an internal corrosive environment;
- instrumentation to record operating pressures and pressure cycles;
- devices to monitor ground movement at geohazard sites;
- external and internal corrosion measurement devices;
- on-line pressure monitoring instruments;
- pressure cycle monitoring software;
- vibration sensors;
- surveys to measure pipe depth, geotechnical conditions, corrosion control effectiveness, and third-party activity near the rights-of-way;
- non-destructive testing at targeted investigation sites;
- in-service pressure-testing;
- regularly scheduled equipment maintenance and monitoring; and
- leak detection.

In addition to the integrity monitoring, Enbridge employs a state of the art Control Center with highly qualified and trained personnel, as further detailed in the direct testimony of Mr. Allan Baumgartner.

Repair processes:

1) Recoating with modern epoxy coating.

This repair method is used to protect the pipe from further external corrosion and is an acceptable repair method when the corrosion has not developed to the point that safety would be compromised. The limitation of this repair method is that it cannot add metal where corrosion has removed metal.

2) Installing a pressure-containing steel sleeve and recoating the outside of the sleeve with a modern epoxy coating.

This repair method is used when recoating alone would not restore the pipeline to the required safety level. The steel sleeve is designed to be at least as strong as the pipe that it is encapsulating.

3) Grind repair.

A preferred method to address crack anomalies and other sharp-edged manufacturing defects is to perform fine grinding to accurately assess the size of the crack and to prevent it from propagating in the future. After the grind repair is complete, the pipe is assessed to determine whether repair method 1 or 2 should also be completed.

4) Cut-out and replacement.

In some rare cases, a section of pipe may be cut out to remove an anomaly and a new piece of pipe welded in its place. However, this method is generally only used so that the pipe material can be studied in a laboratory setting or where a design constraint would prevent the installation of a sleeve.

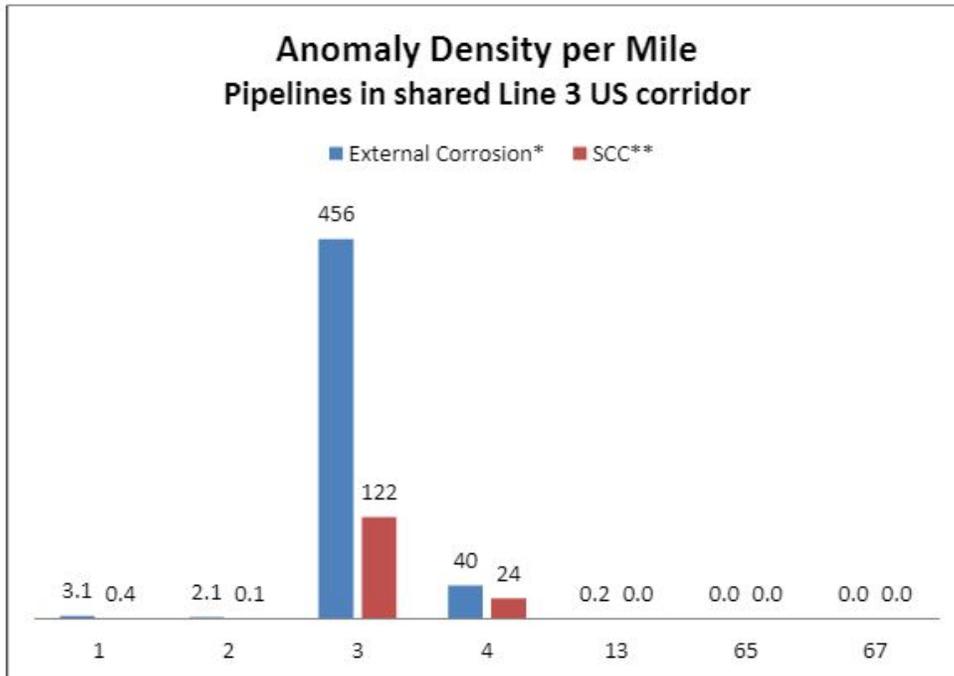
Enbridge has conducted 31 ILI programs (13 for corrosion, 6 for cracking, and 12 for deformation), resulting in over 950 excavations in the last 16 years on Line 3 in the U.S

Enbridge has gathered extensive integrity data on Line 3 throughout its years of operation. Line 3 in the U.S. was built in 1962/1963 **with two characteristics that make this pipeline particularly susceptible to three integrity threats.**

First, on Line 3 in Minnesota, 84 percent of the coating is Polyethylene (“PE”)tape, which has been found to disbond from the pipe, making the pipeline more susceptible to both external corrosion and SCC. As a result, Line 3 in the U.S. has:

- External corrosion on over 50 percent of its pipe sections between welds (referred to as “pipe joints”).
- Ten times as many corrosion anomalies per mile (with a depth of more than 20 percent of the pipe wall thickness) than any other Enbridge pipeline in the same corridor.
- SCC affecting over 15 percent of the pipe joints, and five times as many SCC anomalies per mile (with a depth of more than 10 percent of the pipe wall thickness) than any other Enbridge pipeline in the same corridor.

The figure below shows the density per mile of external corrosion and SCC anomalies for Line 3 compared to the other Enbridge pipelines located in the shared U.S.. corridor.

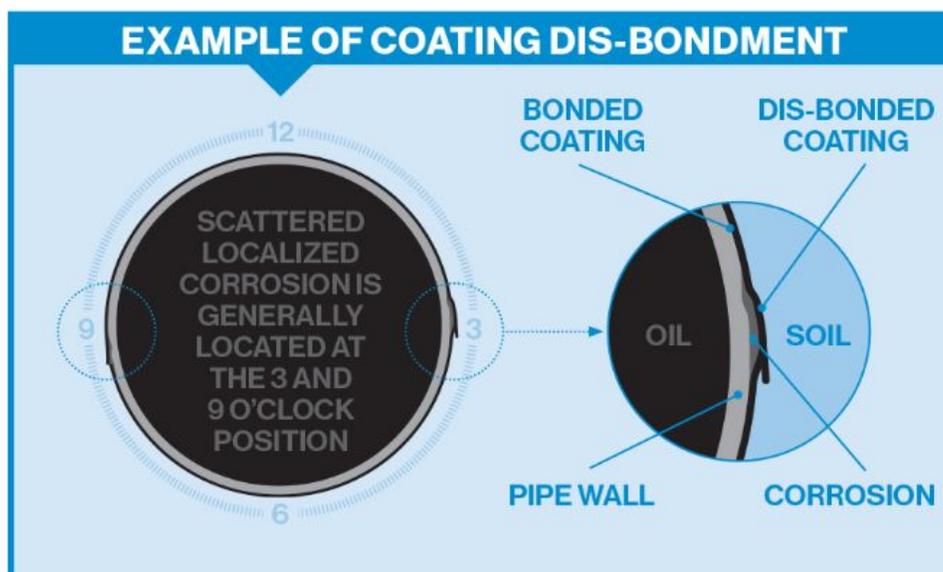


*Corrosion over 20 percent of wall thickness; **crack-fields over 10 percent of wall thickness

Second, on Line 3 in the U.S., 53 percent of the longitudinal welds are flash welded (“FW”), which was a pipe manufacturing process that has an inherently higher susceptibility to the formation of defects along the long seam of the pipe. Although not all FW pipe contain manufacturing defects, there are FW segments of Line 3 where the combination of these defects and internal pipeline pressure developed into long-seam cracking and contributed to some of the historical failures

What is external corrosion and how has the tape coating enabled it to occur on Line 3?

External corrosion is the oxidation of the steel and loss of metal on the exterior of the pipeline. External corrosion on Line 3 is primarily attributed to the coating disbonding from the external surface of the pipe. Disbonded coating creates entry points for water, oxygen, bacteria and acidic compounds in soil to access the surface of the steel and initiate corrosion. The figure below illustrates coating disbondment.



The external coating system on Line 3 is predominantly PE tape, which was wrapped onto the pipeline when the pipeline was positioned over the ditch, just before the pipeline was placed into the ditch and soil was backfilled over the pipeline. At the time the coating was installed, this type of coating was deemed to be a good system for protecting the external surface of the steel pipe and could be applied in a cost effective manner with less health and safety risks compared to some of the previous coating systems. However, several factors have contributed to this coating disbonding from the surface of the steel on Line 3, including:

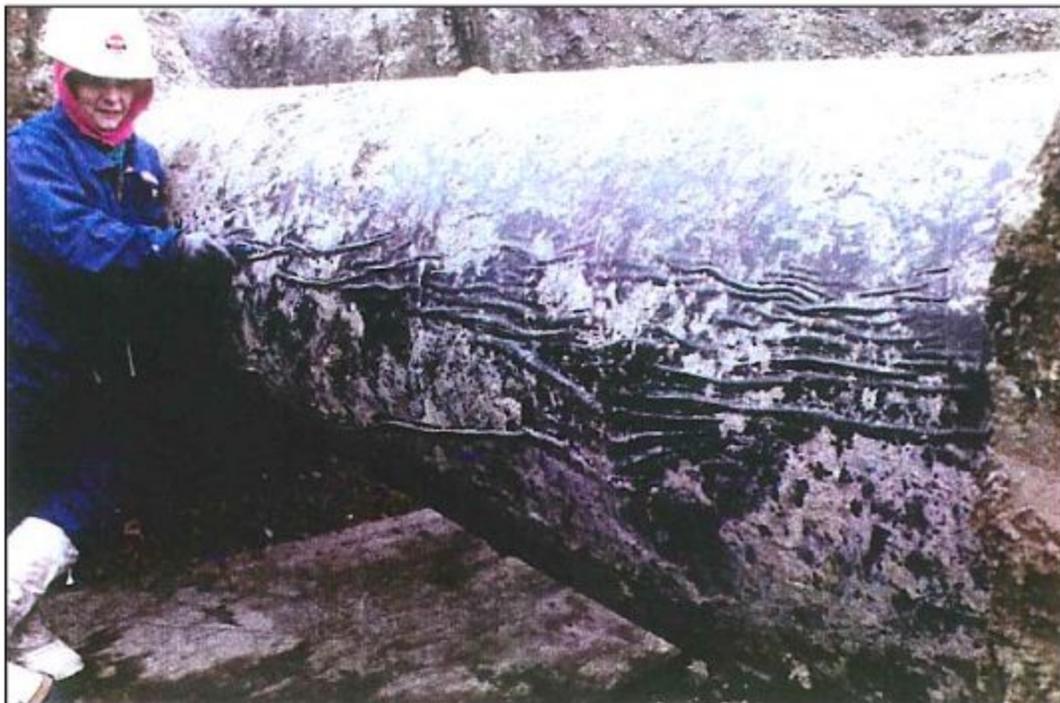
Application Methods:

- **Surface Cleaning:** Prior to installation of the tape coating, the surface of the steel on Line 3 was cleaned by wire brushing, which later turned out to be insufficient to remove a residual oxide and mill scale layer. This layer of oxide and mill scale reduced the available surface area for the tape to bond to the steel.
- **Primer:** The adherence of the coating is improved by painting a primer onto the surface of the steel before the tape coating is applied. Primer was not painted onto Line 3 because its effectiveness was not well understood at the time of construction.
- **Dust and Debris:** The tape coating was installed over the ditch, and the action of the coating machines, along with wind, stirred up dust and debris, which became trapped under the tape, thus reducing the available surface area for bonding to the steel. The photos below show the tape coating installation process for Line 3

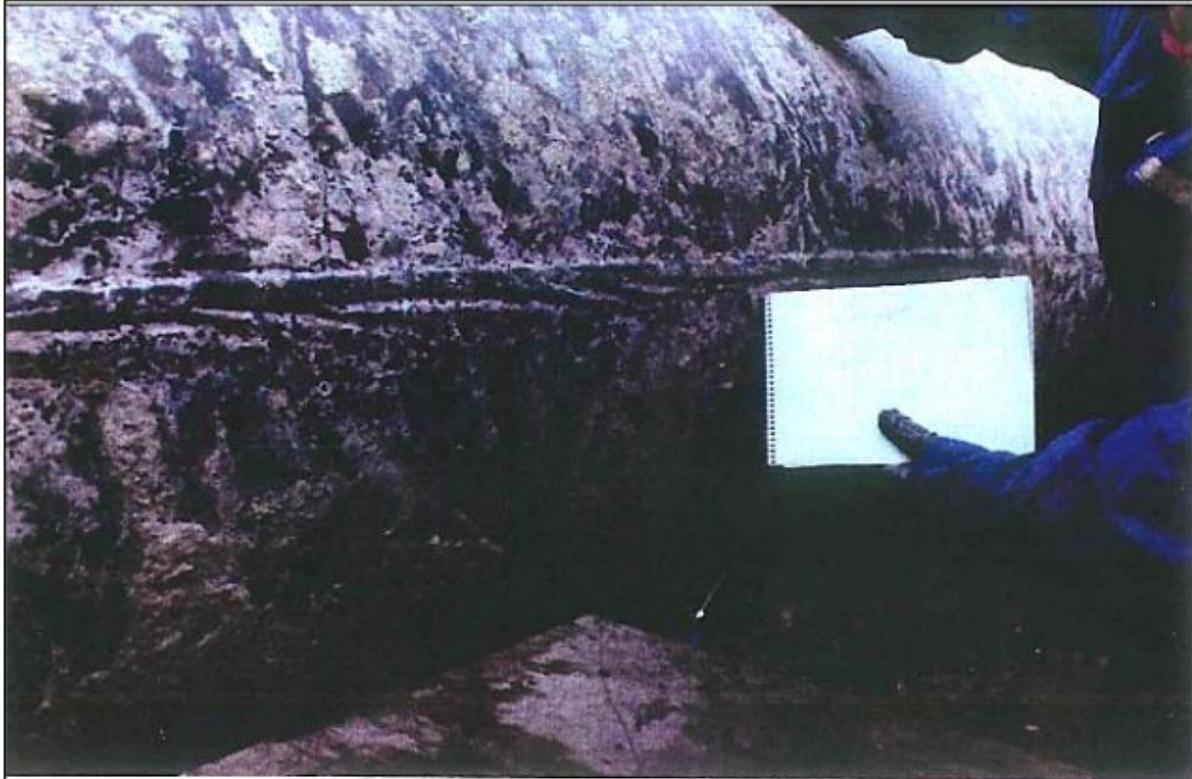




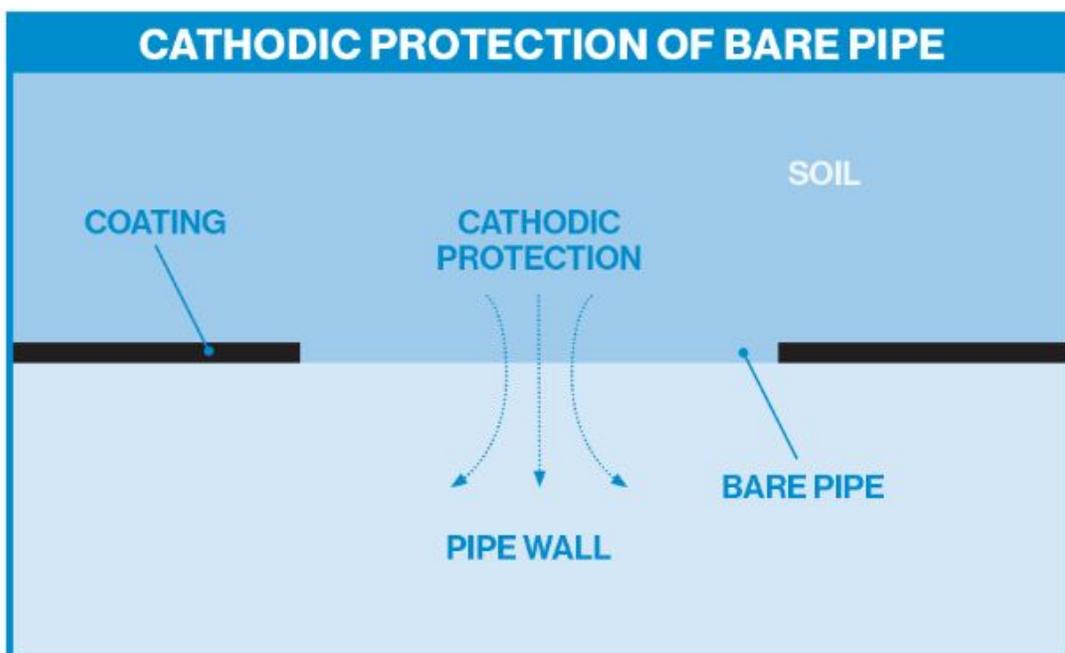
- Soil Stress: Along Line 3, soils have expanded and contracted from seasonal changes in temperature and moisture, and the friction between the pipe and soils with high clay content has stretched the tape coating and caused it to wrinkle. Pipelines in soils with more clay, such as parts of western Minnesota, exhibit more stretching of the tape coating because those soils are more prone to movement from settling and wetting. The photo below shows an example of the effect of soil stress on Line 3's tape coating

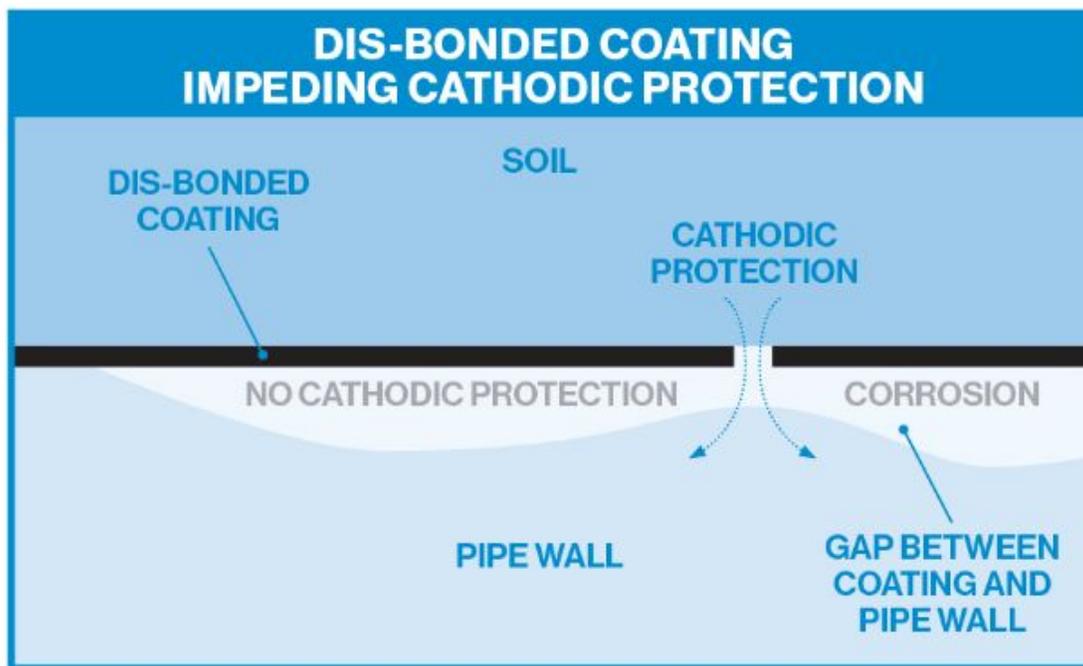


- Bridging over the Longitudinal Seam Weld: Because some longitudinal seam welds create a bump on the surface, the tape coating bridges over this bump and forms a pocket where the tape has not bonded to the surface of the steel. The photo below shows bridging of the tape coating on Line 3



- CP (cathodic protection) Shielding: The dis-bonded tape coating also acts as a shield to the impressed electrical current from the CP system. Thus, the CP current is unable to reach the metal underneath the disbonded coating, reducing the effectiveness of the CP system. The first figure below shows how CP typically works to prevent corrosion on a bare pipe, and the second figure below shows how the disbonded coating on Line 3 interferes with CP, allowing corrosion to occur.





What is stress corrosion cracking and how has the tape coating contributed to it occurring on Line 3?

Stress corrosion cracking is the growth of cracks in a corrosive environment. The combination of a corrosive environment, as well as stress on the pipe steel from internal pipeline pressure and pressure cycles, can initiate SCC. PE tape coated pipelines are more susceptible to SCC because, as the coating disbonds, the CP is shielded from being effective, and a corrosive environment forms under the coating. Operating at higher pressures can initiate and/or increase the growth rate of SCC, which is one of the reasons why the operating pressure of Line 3 has been permanently reduced.

Given the issues with PE tape coating, why was it used on Line 3?

At the time Line 3 was constructed, PE tape coating was an accepted coating choice within the pipeline industry. Tape coating is not universally a poor choice for external coating of pipelines. However, the conditions in which it was installed on Line 3, and the environmental conditions around Line 3 over the pipeline's lifetime, have demonstrated that this type of coating system was not the best choice for Line 3 from a whole lifecycle perspective. The intensity of the maintenance program on Line 3 to maintain pipeline safety will continue to increase.

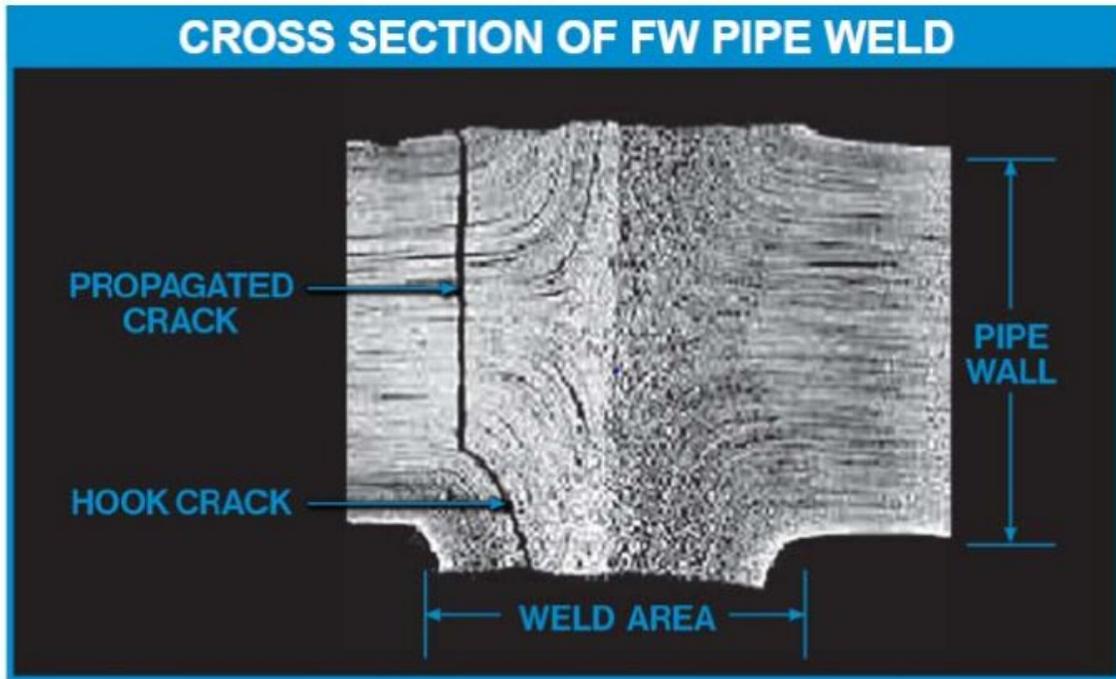
Tape coating exists on other pipelines, and many factors, such as how the tape coating was installed, and the type of environment around the pipeline, result in differences in how well the tape coating adhered to the pipelines. Enbridge closely monitors the condition of external corrosion on all of its pipelines, including its tape-coated pipelines.

What is long-seam cracking and why it has occurred on Line 3?

Long-seam cracking on Line 3 is attributable to defects from the original manufacturing method of the pipe and the impact of higher operating pressures and pressure cycles. Manufacturing and construction defects can be the initiation point of cracks, which can grow through repeated stress called "fatigue" in steel.

Much of Line 3 was made with FW pipe. This type of pipe is made from flat sheets of steel that are curled into the shape of a pipe. The edges are heated until semi-molten, then forced together until molten steel is forced out of the joint and forms a bead. The manufacturing process is susceptible to defects from impurities in the steel, misaligned geometry and cold spots.

Some of the manufacturing defects on the FW pipe on Line 3 are “hook cracks.” Hook cracks develop when inclusions and impurities in the steel become trapped in the weld. The photo below shows an example of hook cracks in a cross-section of a pipe weld. In this example, we can see one of the hook cracks has led to a crack that propagated all the way through the thickness of the pipe wall. This type of failure has occurred on Line 3.



Due to the susceptibility of the FW manufacturing process to defects, FW is no longer used in pipe manufacturing. **Prior to self-imposed pressure restrictions, pressure-cycle-induced fatigue, coupled with defects in the seam welds on Line 3, caused four major releases in Line 3's operating history.** The last large failure from long-seam cracking occurred in 2002 near Cohasset, Minnesota. Enbridge has since permanently lowered the operating pressure on Line 3 and increased the number of monitoring activities to reduce the threat of long-seam cracking and has not had any subsequent failures on Line 3 from long-seam cracking. The susceptibility of the pipeline to this threat would return if Line 3's operating pressure were increased.

Office Memorandum

DATE : July 10, 2003

TO : Cliff Zimmerman
National Transportation Safety Board

FROM : Stephen J. Lee, Supervisor
Emergency Response Team
Minnesota Pollution Control Agency

PHONE : 651/297/8610

SUBJECT : Accident # DCA02-MP002
Enbridge Pipe Line Company 34 Inch Crude Oil Line

A 34 inch diameter pipeline operated by Enbridge Pipe Line Company crosses northern Minnesota. Since the July 4, 2002, Cohasset rupture this pipeline has been under Federal order to operate at reduced pressure to reduce the risk of additional leaks or ruptures. Enbridge may ask the Federal Office of Pipeline Safety for permission to resume normal operating pressures in order to increase the volume of crude oil transported by the pipeline.

Not so voluntary after all! Can share this memorandum.

Please discuss further Line 3's release history.

While Line 3 has been in operation for over 50 years, record keeping since 1990 provides more details regarding the root cause of releases. **Since 1990 Line 3 has experienced 15 failures that released more than 50 barrels of oil during each incident, with 7 of these failures occurring in Minnesota.** Enbridge's use of pressure restrictions, intensive monitoring, and an extensive dig and repair program has prevented further releases

What integrity measures has Enbridge utilized to address the pipe defects and associated integrity threats present on Line 3?

Enbridge has made substantial investments in the maintenance of Line 3, including implementing an aggressive ILI program, undertaking extensive dig and repair programs, **and voluntarily imposing permanent pressure restrictions** that limit operational capacity and flexibility. **For example, to ensure safe and reliable operation of Line 3, Enbridge implemented a voluntary pressure reduction on the discharge of all pump stations in 2008. In 2010, Enbridge extended the pressure restriction to include the entire pipeline to further increase the line's operating safety margin. Finally, in 2012, Enbridge permanently de-rated Line 3's MOP.**

There is no feasible technology or operational changes that can arrest or reverse the external corrosion on Line 3 and/or remove the defects that were inherent in the way the pipe was originally manufactured. As a result, maintenance and repair activities will continue to increase over time on the existing Line 3. The recommended solution is to replace Line 3 with a pipeline that utilizes modern external coating systems and modern pipe quality.

Why was replacement considered for Line 3?

Enbridge has been analyzing the need for replacement of Line 3 for several years because of the increasing maintenance activities associated with external corrosion, SCC, and long-seam-fatigue cracking. As discussed above, these integrity threats are driven by the degrading external coating system on Line 3 and defects from the original manufacturing process of the pipe, and are expected to require continually increasing maintenance.

In 2007-2008, a focus group within Enbridge recommended that segments of Line 3 be replaced because of the high density of identified anomalies. At that time, the optimal maintenance approach was determined to be lowering the pressure on the pipeline in successive steps, which deferred the immediate need for pipeline replacement. In 2008, Line 3's capacity was 503,000 bpd of mixed service, and by 2010, it had been lowered to a capacity of 390,000 bpd of light crude oil. This lowered pressure maintained a safety factor on the line, deferred some of the maintenance work on the anomalies, and still allowed the pipeline to function, albeit at a much reduced rate.

Since implementing a replacement plan is a multi-year and multi-disciplinary endeavor, replacement continued to be evaluated. Data from 2010-2012 crack ILI and 2009-2011 corrosion ILI showed that considerable maintenance work would need to be undertaken to allow the pipeline to continue to operate safely.

For example, the ILI data showed that while cracks were more stable under the lower operating pressure, external corrosion was still growing. **At that time, 70 percent of the 140,000 pipe joints had external corrosion detectable to the ILI tools (corrosion depth of less than 20 percent of the wall thickness is not accurately characterized by the ILI tools), and approximately 900 the pipe joints had corrosion deeper than 50 percent of the pipe wall thickness.** Forecasts based on the ILI data showed that over 18,000 pipe joints in the U.S. and Canada would have a corrosion depth of 50 percent or greater by 2027. In the U.S. alone, approximately 4,000 integrity digs were forecast during the following 15 years to maintain Line 3 at its reduced level of operation. Dig and repair costs were forecasted to exceed \$6 billion through the year 2026, and replacing the segments in the worst integrity condition would only lower the forecasted cost to \$4.3 billion. Further pressure reductions could not be implemented because the pipeline was already operating at the lowest operable pressures.

Enbridge recognized that, while replacing segments would help to resolve the most urgent integrity threats, extensive maintenance would still remain on un-replaced sections. Although the average dig per mile for the whole line was around 10 to 20, which is below the rule-of-thumb of greater than 20 digs per mile before reaching an economic break even point between digs and repairs, the replacement of segments would not return the pipeline to its original operating capacity or improve overall system flexibility. Additionally, the non-replaced segments would continue to degrade and would likely require replacement in the future.

Also, as discussed in Jack Fleeton's direct testimony, Enbridge's shippers supported a full replacement of Line 3 as the most efficient means to both mitigate the increasing integrity threats and achieve a near-term restoration of the original operating capability of Line 3. These factors, along with the ever-increasing disturbance to the environment and landowners due to successive integrity digs, led Enbridge to determine full replacement was the best solution.

Line 3 has experienced an accelerated rate of deterioration associated with external corrosion, SCC, and long-seam cracking due to the disbanded coating and fatigue growth of defects in the FW long

seams. I consider Line 3 to be in the deterioration stage (Stage 3), as external corrosion growth is increasing in an exponential fashion. Therefore, Line 3 is on a path of ever increasing repairs to mitigate operating risk until it is replaced.

Has additional ILI data been obtained since the initial replacement assessment was conducted?

Line 3 has been completely re-inspected since the original analysis and justification to replace Line 3 was completed in 2012. The additional inspections include three corrosion detection technologies (magnetic flux leakage, axial magnetic flux leakage, and ultrasonic metal loss detection), a high resolution caliper (detecting geometric anomalies such as dents), and an ultrasonic crack detection tool. The inspections for the portion of Line 3 in the U.S. from Gretna to Clearbrook were completed in 2014, and inspections for the portion from Clearbrook to Superior were completed in 2015.

Results from these inspections continue to support the replacement decision made in 2012/13. Specifically, the 2014/15 ILI data reaffirmed the updated 15 year dig forecasts follow an exponential trend across all of Line 3, and:

- Over 70 percent of the 140,000 pipe joints are experiencing external corrosion;
- Corrosion deeper than 50 percent of the pipe wall thickness would increase to affect over 3,000 of the pipe joints in 2016 – an increase from approximately 900 pipe joints in 2012; and
- Over 25,500 pipe joints will have a corrosion depth of 50 percent or greater by 2030 – an increase from approximately 18,000 pipe joints forecast for 2027

Based on the most recent ILI data, how many integrity digs are forecasted to continue long-term operation of Line 3 at its current operating conditions?

Based on the most recent ILI data, the number of digs related to long-seam cracking will remain stable as a result of Enbridge permanently reducing the operating pressure in 2012. The combined required long-seam cracking and SCC digs are forecast at over 750 digs in the next 15 years in the U.S. The forecasted number of corrosion digs, will continue to increase in an exponential fashion because of the disbanded coating. Based on the 2016 assessment, over 6,200 corrosion digs are required over the next 15 years in the U.S.

Combined, the total digs required to maintain Line 3 at its current operating condition over the next 15 years is approximately 7,000 digs in the U.S., with approximately 6,250 of these digs in Minnesota.

What is the current estimated cost to continue a dig and repair program on Line 3, and how does it compare to the replacement cost estimate?

Conceptually, it may be possible to restore Line 3 to its original operating capacity **if Enbridge invested nearly \$8 billion in repairs** over the next 15 years in Canada and the U.S., with approximately \$2 billion in the U.S. alone. However, in reality, it is not feasible to conduct such an extensive dig and repair program, which would require multiple digs in concentrated areas. The resources required, and the impact to the environment and landowners along the pipeline, would be extraordinary. Moreover, since the total estimated cost to replace Line 3 is \$7.5 billion (approximately \$2.1 billion for the U.S. portion), we are at the approximate break-even point when comparing the cost of replacement to the present value of continued repairs. Thus, the 2016 re-analysis of dig versus replace concluded that Line 3 replacement should be pursued as expeditiously as possible because restoring the original capacity is not feasible considering the condition of the pipeline

How will compliance with the proposed Consent Decree impact integrity management of Line 3?

The proposed Consent Decree requires Enbridge to replace Line 3 as expeditiously as possible after receiving all necessary regulatory approvals, which Enbridge is required to seek. In the interim, Enbridge must meet specified pressure limitations, and must continue an extensive dig and repair program. In the event Line 3 is not retired by December 31, 2017, Enbridge must complete and re-validate ILI annually for crack, corrosion and geometry threats (Enbridge presently inspects every 12 to 18 months).

Compliance with the requirements of the proposed Consent Decree will increase the capital expenditure requirements of Line 3 in the range of \$5 million to \$40 million per year in the U.S. starting in 2018 until Line 3 is permanently deactivated. In addition, compliance with the proposed Consent Decree will increase operating expenses (mainly for ILI) approximately \$8.5 million per year in the U.S. until Line 3 is permanently deactivated, which is up to 3 times the current amount, depending on the date Line 3 is retired.

Repair/Replace Considerations for Pre-Regulation Pipelines Final Report Prepared by Kiefner and Associates, Inc., for PHMSA