ENBRIDGE ENERGY, LIMITED PARTNERSHIP

MINNESOTA PUBLIC UTILITIES COMMISSION

MPUC DOCKET NOS. PL9/CN-14-916

TESTIMONY OF LAURA KENNETT

January 31, 2017

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Laura Kennett, and my business address is 10201 Jasper Avenue NW, Edmonton, Alberta, Canada, T5J 3N7.

Q. What is your position with Enbridge?

A. My current position is Supervisor, Pipeline Asset Integrity Projects.

Q. Briefly describe your educational and professional background.

A. My formal education includes a diploma in Mechanical Engineering Technology, a certification in Environmental Resources Management, a B.Eng. in Mechanical Engineering, and a M.Sc. in Engineering and Technology Management. I am a registered professional engineer in Alberta, Canada.

My professional experience includes mechanical maintenance and environmental program execution at a steel mill and bar mill; engineering support of construction of petroleum production facilities; crude oil storage facility design, construction, and commissioning; liquid pipeline integrity inline inspection ("ILI") and dig program execution; operations engineering support for liquid pipelines, terminals, and related facilities; and sponsorship of liquid pipeline integrity projects and asset management. I have over 18 years of experience in design, construction, operations, metallurgy, project management, and asset management. My Statement of Qualifications is provided as **Schedule 1**.

Q. Describe your current role with Enbridge.

A. As a professional engineer, I have a commitment and a responsibility for public safety and well-being. In addition, as an employee of Enbridge, I oversee projects that support the continued safe operation and integrity management of our pipelines. The types of projects I typically sponsor include: pipe replacement, hydrostatic pressure tests, slope instability and river crossing remediation, and projects to mitigate external corrosion. Sponsoring projects involves ensuring the project is justified based on integrity science and business needs, engaging a project team to execute the project, and organizing funding for the project. My

role requires continuous collaboration with other groups at Enbridge to assess the integrity, risk, feasibility, environmental impact and whole lifecycle of the project.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the basis, from the integrity perspective, for the decision to replace Line 3.

Q. Please identify the sections of the Certificate of Need Application which you are sponsoring for the record.

A. I am sponsoring or co-sponsoring the following sections of the Certificate of Need Application:

- Section 1.4 Background on Line 3's Integrity Management Program;
- Section 3.1 Replacing Line 3 is the Optimal Maintenance Alternative to Ensure Safe Operation;
- Section 3.2 Overview of Pipeline Maintenance;
- Section 3.3 Federal Requirements for Integrity Management Programs;
- Section 3.4 Overview of Enbridge's Integrity Management Program;
- Section 10.1.1.A No Action Alternative; and
- Appendix B Safety Report, Section III.A.4.

Q. Do you have any changes to the sections of the Application you are sponsoring?

A. The Safety Report (provided as Schedule 3 to Mr. Paul Eberth's direct testimony) has been updated, and I am sponsoring Section III.B of the updated report. Further, I will provide more detail regarding, and further clarify, the integrity threats impacting Line 3.

Q. What schedules are attached to your direct testimony?

A. Schedule 1 – Kennett Statement of Qualifications
Schedule 2 – Pipeline Integrity ILI and Repair Process Flowchart
Schedule 3 – Integrity Dig Steps

II. ENBRIDGE'S INTEGRITY MANAGEMENT PROGRAM

Q. What is integrity management?

A. Pipeline integrity management is defined in the Code of Federal Regulations Title 49 – Transportation, Subpart 195.452, and Appendix C. By definition, integrity management establishes programs and practices to identify, inspect, assess, evaluate, and remediate integrity risks, as well as methods to measure the effectiveness of integrity program performance. An integrity management program ensures pipelines can be operated safely for their intended purpose and in accordance with the federal regulations. Enbridge has integrity management programs for its pipeline system, including Line 3.

Q. Does Enbridge's integrity management program comply with applicable federal regulations?

A. Yes. In addition, although the federal regulations require pipeline operators to develop an integrity management program which applies to pipeline segments that could affect High Consequence Areas ("HCAs"), Enbridge applies its integrity management program across its entire pipeline system.

Q. Please describe Enbridge's integrity management program.

A. As described in more detail in Section 3.4 of the Certificate of Need Application, Enbridge's integrity management program is a comprehensive pipeline and facility maintenance regime to help achieve Enbridge's goal of zero releases, as well as leadership in safety management and operational reliability. The program has four main components:

- Prevention of integrity threats;
- Monitoring of integrity threats;
- Mitigation of integrity threats; and
- Verification of the effectiveness of the integrity management program.

The pipeline integrity processes and procedures define key activities that ensure threats to the pipeline are understood and addressed, support integration and alignment of information, communicate clear accountabilities for processes, and clarify responsibilities and relationships in achieving integrity of the pipeline system.

Q. What is an integrity threat?

A. 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; and
- 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.

Q. How does Enbridge prevent threats to its pipelines?

A. Threat prevention occurs over the complete lifecycle of a pipeline and Enbridge assesses the "fitness" of the pipeline for the service it is intended to perform, considering hazards and risks.

Prior to operation, threat prevention is addressed through a design that avoids or lessens integrity threats and by implementing stringent construction quality requirements. During operation, Enbridge prudently monitors and mitigates threats by first assessing potential threats to each of its pipelines. In order to assess the potential threats to its pipelines, Enbridge considers construction records, previous integrity program results, operational performance, learnings from the industry, and changes in regulations. The results from threat assessments lead to a plan that specifies the type of ILI technology to use and the re-assessment time interval required to proactively manage changes in threats and anomalies. See Section 3.4.2 of the Certificate of Need Application for additional information regarding the ILI technology employed.

Enbridge also proactively employs various methods to prevent or reduce the risks of threats to its pipelines. For example, to prevent external corrosion, Enbridge applies a protective coating and uses cathodic protection ("CP"). The protective coating adheres to the external surface of the pipe to form a barrier between the pipe steel and the external, potentially corrosive environment. CP inhibits external corrosion by attaching sacrificial anodes, which corrode instead of the pipe, and/or by impressing a small electrical current through the pipe. To prevent cracking, including environmentally assisted cracking such as stress corrosion cracking and fatigue cracking, Enbridge applies stringent design and construction requirements to avoid the initiation of cracks, and monitors and manages pressure cycling to prevent growth of cracks. The prevention measures employed by Enbridge are described in more detail in Section 3.4.1 of the Certificate of Need Application.

Q. What is pressure cycling?

A. In simple terms, pressure cycling is a repeated change in the operating pressure of a pipeline. The most extreme example would be turning a pipeline on and off repeatedly. Pressure cycling severity is an important factor because it is a driving force behind crack initiation and crack growth.

Q. How does Enbridge monitor the condition of its pipelines?

A. 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.

Q. Please explain in more detail how ILI data informs the integrity management program for a pipeline system.

A. ILI tools detect anomalies, and the data is analyzed to classify these anomalies. Integrity digs are issued for anomalies that meet criteria based on size and type to ensure the pipeline can continue to function at its intended capacity. When an anomaly is excavated, non-destructive examination is performed by qualified technicians, and the results are compared back to the ILI data to validate the accuracy of the ILI data. If differences are noted between ILI data and field results, the ILI data is re-analyzed to determine if more or fewer anomalies require excavation. See the Pipeline Integrity ILI and Repair Process flowchart attached as **Schedule 2**. This feedback loop is part of Enbridge's core process of plan, do, check, act and continuous improvement in the integrity management program:

Plan: Assess the integrity (fitness) of a pipeline to determine if it is "fit" for service considering safety, environment hazards and risks, and current and proposed operating conditions. Planning includes hazard assessment, threat assessment, development of prevention and mitigation strategies, setting re-validation timings, selecting ILI technologies, selecting anomalies for validation and examination, and preparation of budgets for maintenance.

Do: Execute inspection, prevention and rehabilitation activities, and data validation and correlation.

Check: Collect the results from the activities undertaken in "Do" and validate the effectiveness of the program including the influence of potential human factors.

Act: Determine whether additional measures beyond the base plan are required to ensure safety. Additional mitigation strategies may include: pressure restrictions, additional investigative excavations, advanced data calibration, modified revalidation interval, hydrotesting, and pipe replacement.

Continuous Improvement: Improve the overall program efficiency, effectiveness and reliability through people, processes and technology. Examples of Continuous Improvement activities include research, development, and innovation for improved ILI and examination technologies; event learning; improved interpretation and decision protocols; program health checks, audits, and management reviews; benchmarking; performance measurement; and improvements to system operations that reduce threats to the pipeline system.

Q. How does Enbridge mitigate threats to the fitness of its pipelines?

A. Enbridge requires mitigation of integrity threats before they may pose a safety risk. Pipeline anomalies that meet Enbridge's threshold for excavation are addressed through maintenance activities, including dig and repair, adjustments in operational pressure, and/or replacement. Anomalies below Enbridge's excavation threshold are re-inspected at regular intervals and mitigated in the future should they progress and exceed the excavation threshold. Enbridge's excavation thresholds are more stringent than what is required by federal regulations and are based on detailed analysis, industry experience, incident investigation, and field verification.

Q. Please describe Enbridge's dig and repair program.

A. When Enbridge's ILI program identifies anomalies that require excavation and visual inspection, Enbridge obtains the required environmental and regulatory permits, notifies affected landowners, and identifies all existing utilities in the vicinity of the area to be excavated. Enbridge then excavates around the section of buried pipe so that it can be cleaned and examined and then repaired, as needed. This is referred to as a dig and repair program, and individual digs are referred to as "integrity digs." Repair typically includes cleaning and examining the external surface of the pipe, and one, or a combination, of the following repair methods:

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.

Upon completion of the examination and repair, subsoil and topsoil are replaced, and the site is restored by grading, planting, and reseeding, as necessary. The steps of the integrity dig process are depicted in **Schedule 3**. Integrity digs involve disturbance of the land, which may interfere with the landowner's use of the property. However, integrity digs are necessary to maintain the safety of the pipeline. For further discussion of integrity digs, see Section 3.4.3 of the Certificate of Need Application.

Q. What are pressure restrictions, and when are they employed?

A. A pipeline is designed to enable it to transport a specified volume at its maximum operating pressure ("MOP"). As defined in the federal regulations, the MOP is a maximum of 72 percent of the design strength of the pipe and provides a safety buffer between the highest operating pressure and the pressure the pipe material is statistically deemed to withstand. If safety or integrity issues are identified, the pipeline pressure may be reduced below its MOP temporarily or permanently to ensure that the pipeline remains safe to operate. Pressure restrictions may be voluntarily imposed by the pipeline operator or ordered by a regulator.

Temporary pressure restrictions may be imposed when an ILI reports a severe anomaly that necessitates a pressure reduction to ensure a factor of safety is maintained. The restriction may be removed after the anomaly is excavated, examined, and repaired. Temporary pressure restrictions may also be imposed if Enbridge is unable to verify the reliability of the ILI data. These restrictions may be removed after evaluating the pipe using additional inspection methods, such as performing more ILI, completing more dig and repair programs, pressure testing, and/or completing an engineering assessment.

When it is determined that on-going maintenance activities will not feasibly restore the pipeline back to its MOP, a permanent pressure restriction may be imposed. The lowered MOP enables the continued operation of the pipeline, at a lower pressure, while maintaining a factor of safety based on the condition of the pipeline. Pressure restrictions can cause significant operational challenges and typically limit capacity and operating flexibility.

Q. How do pressure restrictions help to protect a pipeline's integrity?

A. Ruptures can occur when the strength of the pipe is no longer able to withstand the internal pressure of the pipeline. Pressure restrictions reduce the internal pressure of the pipeline to increase the factor of safety and prevent a rupture.

However, pressure restrictions have limitations in that they do not stop corrosion and may not always prevent crack growth. Therefore, even if a pressure restriction is imposed on a pipeline, on-going integrity measures must be implemented not only to maintain the pipeline capacity, but also to remove the time-dependent threats.

Q. Has Enbridge developed a pipeline replacement assessment procedure?

A. Yes. Enbridge has long considered pipe replacement as a method to address integrity threats. The process for assessing pipeline replacement was formally communicated to the Pipeline Hazardous Materials Safety Administration ("PHMSA") as a requirement under the Corrective Action Order for the Lakehead System after the Marshall failure. This procedure is continuously updated and refined based on increased knowledge and improved technologies. Line 3 was one of the first lines to be analyzed using the Pipeline Replacement Assessment Procedure due to its integrity maintenance requirements.

Q. What factors are considered in a repair versus replacement analysis?

A. Enbridge begins by forecasting a 15-year outlook for maintenance digs for time-dependent threats, such as corrosion and stress corrosion cracking ("SCC"), where the threat increases over time. While ILI tools do not predict corrosion or cracking, the results show the changes over time. Enbridge applies growth rate algorithms to develop a forecast of future maintenance requirements. A general rule-of-thumb that Enbridge uses is to do more detailed analysis of the potential need to replace sections of a pipeline where more than 20 digs per mile are forecasted over 15 years. Greater than 20 digs per mile is often the point at which replacement and repair are equal from a cost perspective.

Even when the dig density is less than 20 digs per mile, certain factors can dictate further analysis of replacement, such as:

- impact to the environment and landowners;
- risk reduction;
- operating reliability requirements;
- future anticipated need for the pipeline capacity;
- site-specific conditions affecting accessibility or feasibility;
- financial recovery mechanisms, such as tolls and tariffs; and
- regulatory orders.

III. INTEGRITY HISTORY OF LINE 3

Q. Please describe the integrity monitoring conducted for Line 3.

A. ILI tools are reliable for monitoring the growth of corrosion, SCC, and cracking, and have been used on Line 3. 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.

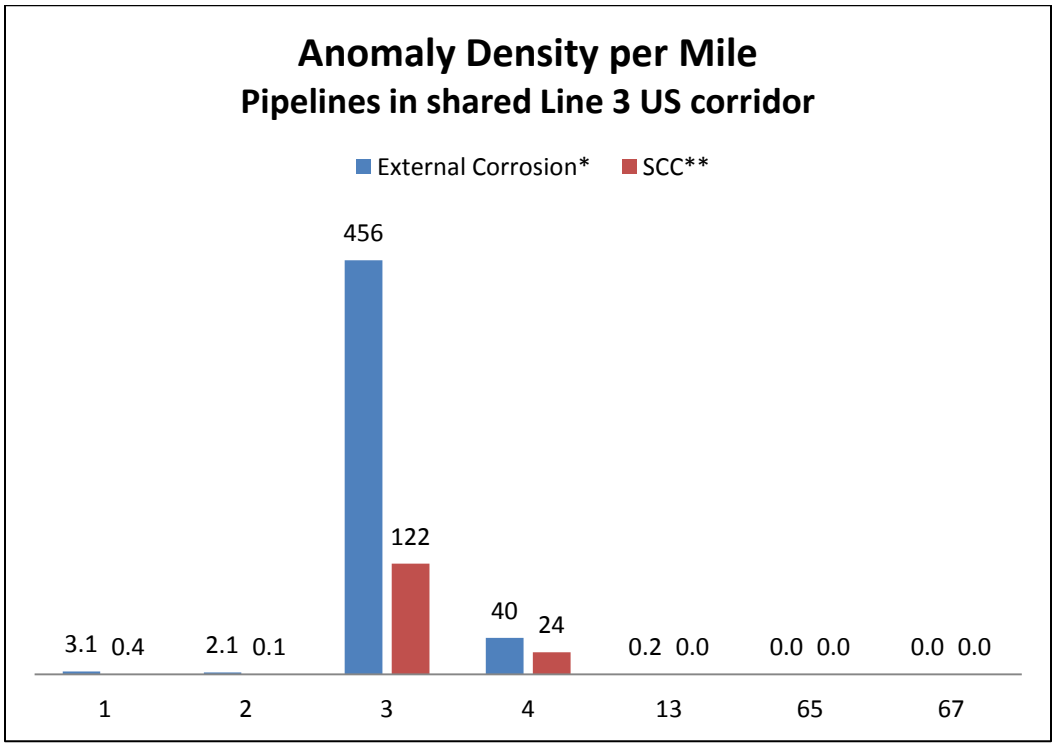
Q. What integrity threats have been identified on Line 3?

A. 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 dis-bond 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.



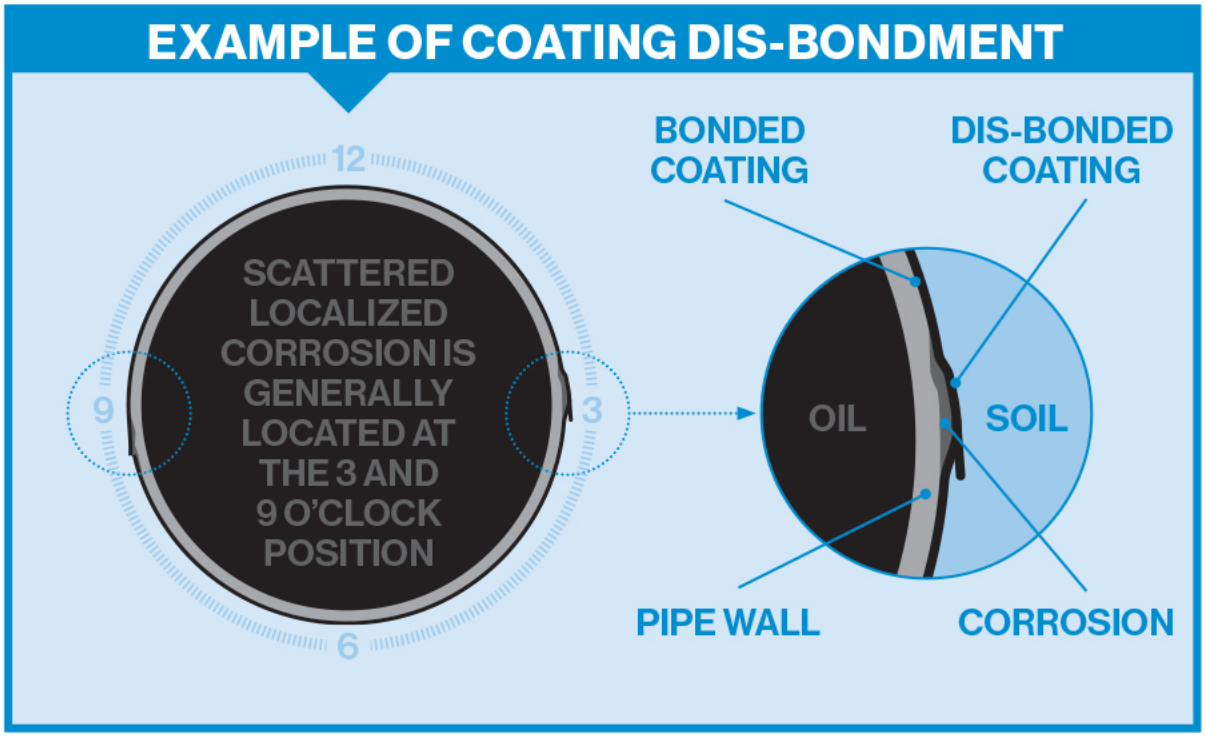
*Corrosion over 20 percent of wall thickness; **crack-fields over 10 percent of wall thickness

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.

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

A. 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 dis-bonding from the external surface of the pipe. Dis-bonded 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 dis-bondment.

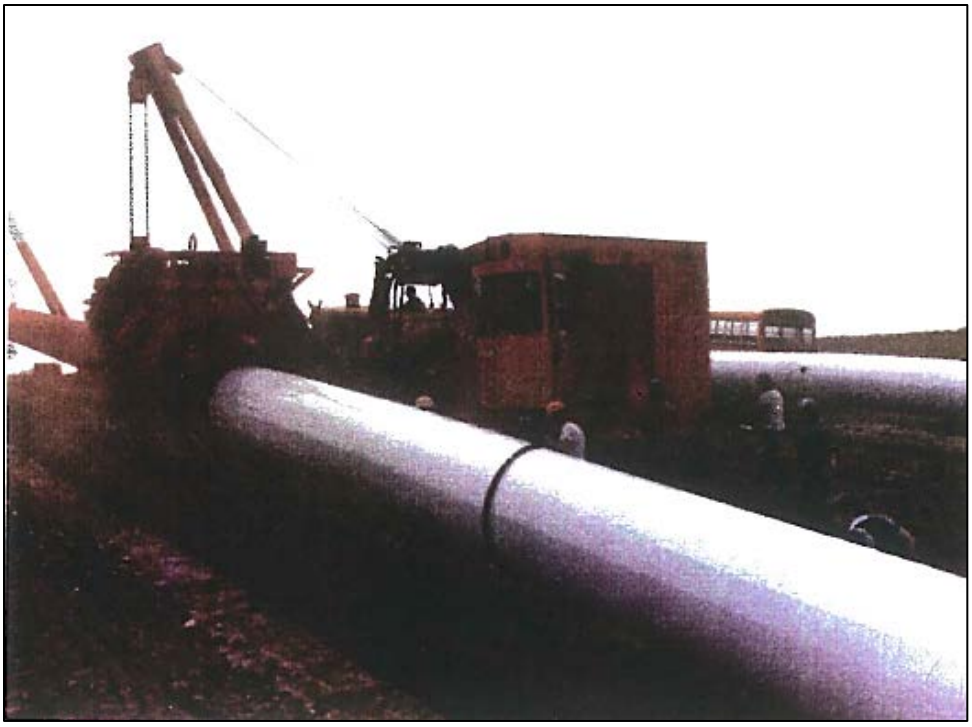


The external coating system on Line 3 is predominantly PE tape, which was wrapped onto the pipeline when the pipeline was positioned over the ditch, just before the pipeline was placed into the ditch and soil was backfilled over the pipeline. At the time the coating was installed, this type of coating 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

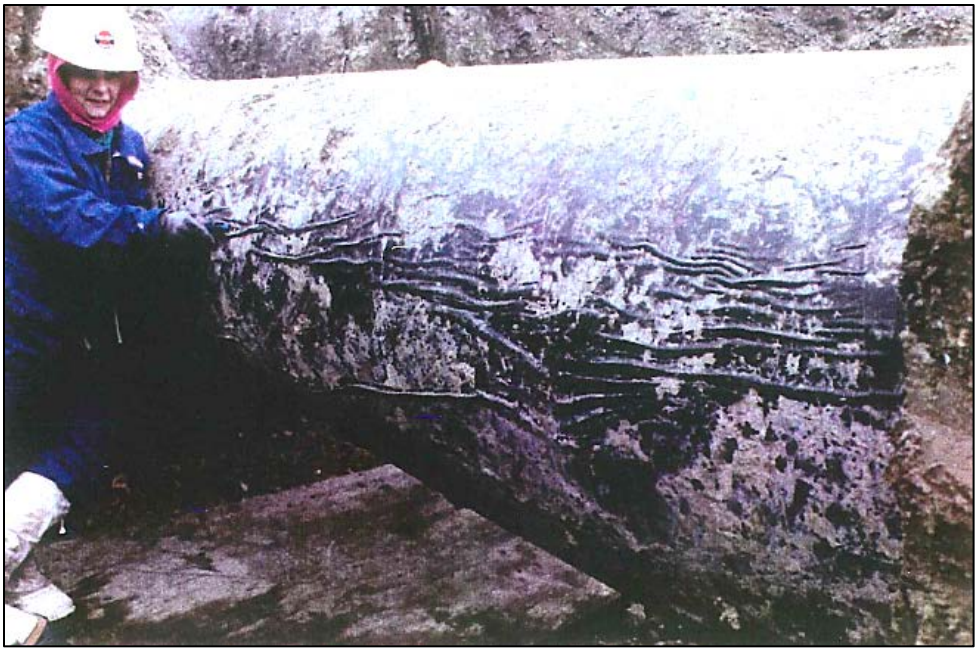
have contributed to this coating dis-bonding from the surface of the steel on Line 3, including:

Application Methods:

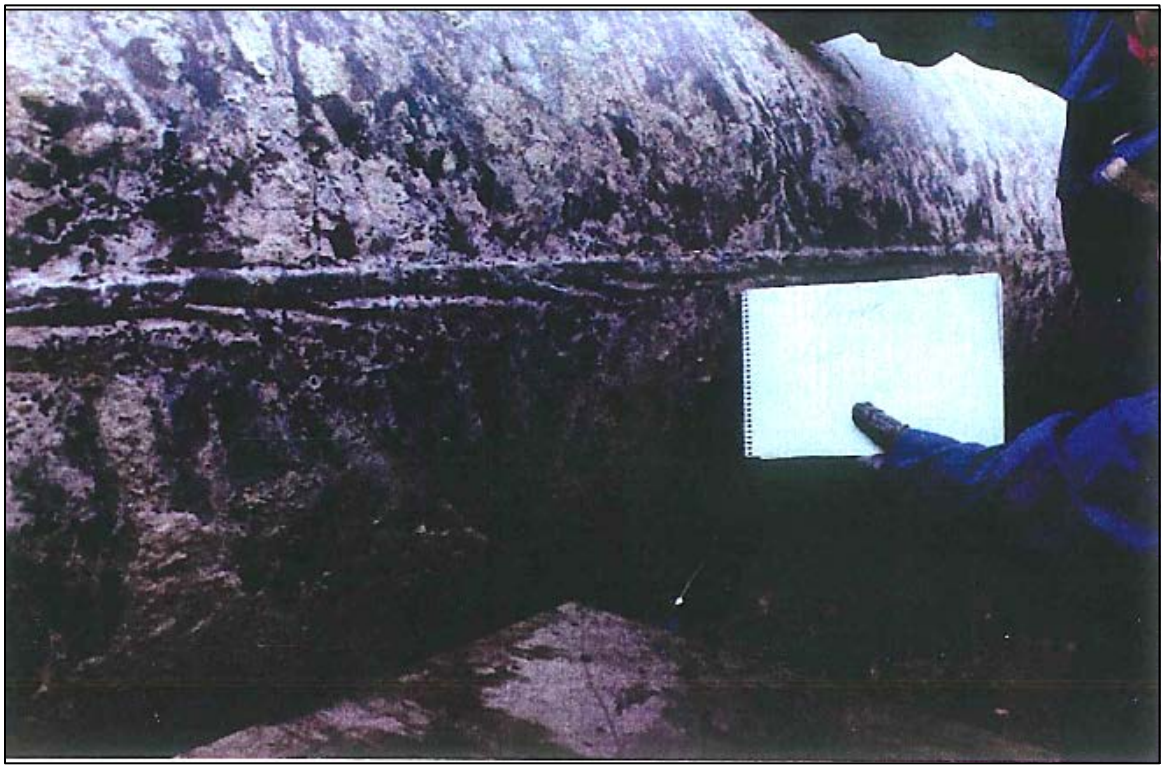
- Surface Cleaning: Prior to installation of the tape coating, the surface of the steel on Line 3 was cleaned by wire brushing, which later turned out to be insufficient to remove a residual oxide and mill scale layer. This layer of oxide and mill scale reduced the available surface area for the tape 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.



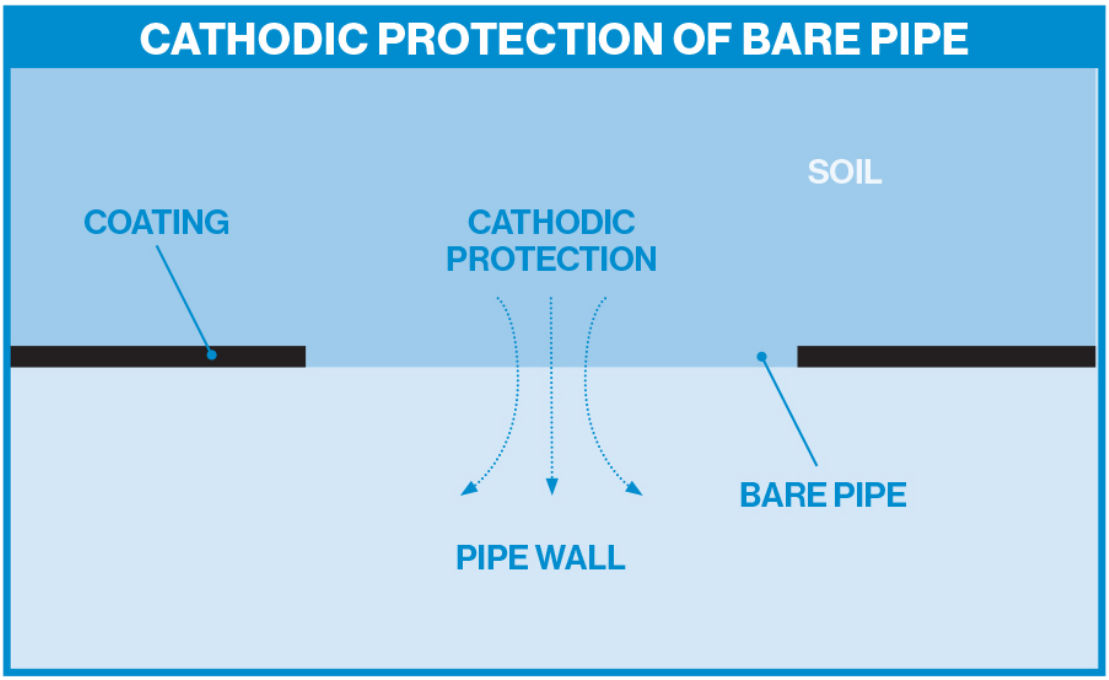
- Soil Stress: Along Line 3, soils have expanded and contracted from seasonal changes in temperature and moisture, and the friction between the pipe and soils with high clay content has stretched the tape coating and caused it to wrinkle. Pipelines in soils with more clay, such as parts of western Minnesota, 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.

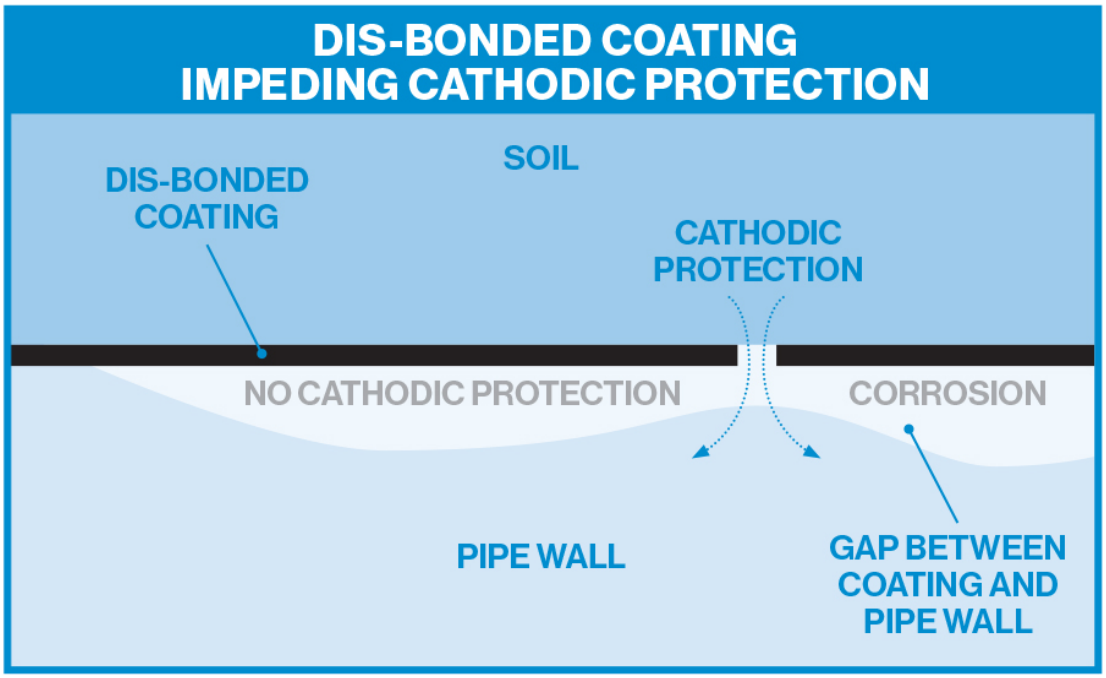


- Bridging over the Longitudinal Seam Weld: Because some longitudinal seam welds create a *bump* on the surface, the tape coating bridges over this bump and forms a pocket where the tape has not bonded to the surface of the steel. The photo below shows bridging of the tape coating on Line 3.



- CP 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 dis-bonded 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 dis-bonded coating on Line 3 interferes with CP, allowing corrosion to occur.





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

A. 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 dis-bonds, 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.

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

A. 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.

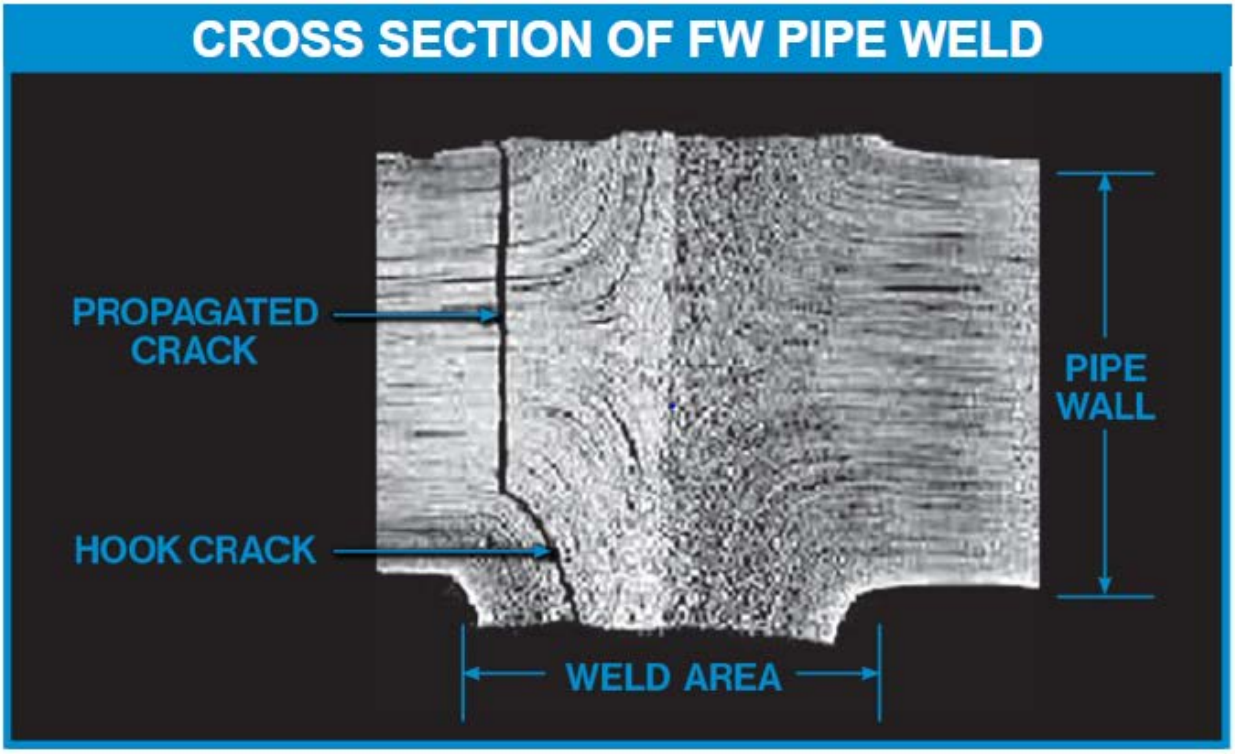
Q. What is long-seam cracking and why it has occurred on Line 3?

A. 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, mis-aligned 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.

Q. Please discuss further Line 3's release history.

A. 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.

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

A. 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.

IV. LINE 3 REPLACEMENT ASSESSMENTS

Q. Why was replacement considered for Line 3?

A. 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 of 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 breakeven 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.

Q. How will replacement of Line 3 help to mitigate the risk of failure?

A. Equipment generally goes through the following stages of physical condition:

Stage 1: Initial

- May reveal inherent weakness or fault in design, materials or fabrication

Stage 2: Mature

- Low, stable rate of damage accumulation
- Predictable, reliable equipment

Stage 3: Deterioration

- Accumulated damage and increased rate of deterioration
- Reduce reliability and service interruptions

Stage 4: Terminal

- Rate of deterioration is increasing rapidly and is not easy to predict

Equipment with time-dependent threats goes through these stages uniquely depending on its design, construction, operating conditions, and maintenance regimes. As time-dependent threats intensify, they increase the operating risk, which is mitigated with repair programs or replacement.

Line 3 has experienced an accelerated rate of deterioration associated with external corrosion, SCC, and long-seam cracking due to the dis-bonded 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.

V. UPDATED LINE 3 REPLACEMENT ASSESSMENT

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

A. 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.

Q. 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?

A. 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 dis-bonded 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.

Q. 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?

A. 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.

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

A. 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) to 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.

VI. CONSISTENCY OF LINE 3 ASSESSMENT WITH REPLACEMENT GUIDANCE

Q. Are you familiar with the *Repair/Replace Considerations for Pre-Regulation Pipelines Final Report* prepared by Kiefner and Associates, Inc., for PHMSA?

A. Yes.

Q. What is the purpose of the Kiefner Report?

A. The Kiefner Report aimed to develop a guideline to help operators of pipelines constructed prior to the 1970s decide when pipe replacement makes more sense than continuing to do the necessary repairs to maintain the serviceability of the pipeline.

Q. Is Enbridge's repair/replace analysis for Line 3 consistent with the guidelines outlined in the Kiefner Report?

A. Yes. The Kiefner Report states that "replacement may become a rational choice if the continuing cost of managing integrity for an older pipeline or system becomes too high in comparison to the cost of replacement." As discussed above, based on a quantitative analysis, full replacement of Line 3 is a rational choice because the current estimated repair costs are more than the cost of replacement.

The Kiefner Report also notes the importance of considering replacement when a pipeline, such as Line 3, has FW pipe, which is classified as "legacy pipe," and has time-dependent threats created by the failing coating system. The Kiefner Report states, "In terms of guidelines for repair/replace decisions, any systematic threat that affects an entire segment such as bare pipe could make the segment a candidate for replacement." The Line 3 legacy pipe and coating issues fall in line with this statement.

Finally, the Kiefner Report includes a series of charts that, when applied to a pipeline, lead either to continuing integrity assessments and maintenance in accordance with regulations, or scheduling replacement if it is not feasible to assess, respond to, and mitigate threats so as to prevent releases. Although Enbridge is safely managing Line 3 today with increased inspection frequencies and the use of the highest resolution ILI tools, the increasing external corrosion threat jeopardizes the future viability of the pipeline because of the challenges in

implementing an extensive dig and repair program. Based on the Kiefner Report's guidance, replacement is the appropriate method to address Line 3's integrity issues.

Q. Has PHMSA issued any other recent guidance supporting replacement of Line 3?

A. Yes. PHMSA issued an advisory bulletin (ADB 2016-4) on June 15, 2016 titled "Pipeline Safety: Ineffective Protection, Detection, and Mitigation of Corrosion Resulting from Insulated Coatings on Buried Pipelines." In this advisory bulletin, PHMSA emphasized the need to design, install, and maintain a pipeline with coatings that do not create an environment of CP shielding and moisture that can lead to excessive external corrosion and SCC. Line 3 has these occurrences, as its coating is dis-bonding with moisture ingress and CP shielding, resulting in growth of external corrosion and SCC.

The PHMSA advisory bulletin recommends that inadequate external corrosion prevention may be addressed through replacing the pipeline, repair or re-coating compromised portions, conducting more frequent reassessments with appropriate assessment tools, coordinating data from ILI technologies, using a more stringent repair criteria, applying advanced ILI data analysis techniques to account for the potential growth of corrosion under coatings, conducting subsequent analysis of ILI data and pipeline excavations to confirm the accuracy of the ILI data, and assessing and adjusting operational and environmental conditions.

At the time the bulletin was issued, Enbridge was already undertaking each of these recommendations for Line 3 by:

1) increasing the frequency of ILI for external corrosion to every 12 to 18 months, whereas regulations require a minimum inspection frequency of 5 years;
2) using high resolution ILI tools and advanced ILI data analysis to monitor changes in anomalies and overlay data from multiple ILIs to identify locations where threats may be interacting;
3) confirming accuracy of ILI data through correlation with field examinations;
4) employing more stringent corrosion repair criteria compared to the 80 percent of the wall thickness required in regulations;
5) removing the existing coating during integrity digs and replacing it with a coating that has superior bonding capabilities and does not shield the CP currents; and

6) planning a replacement to address the coating and CP shielding issues across the entire pipeline.

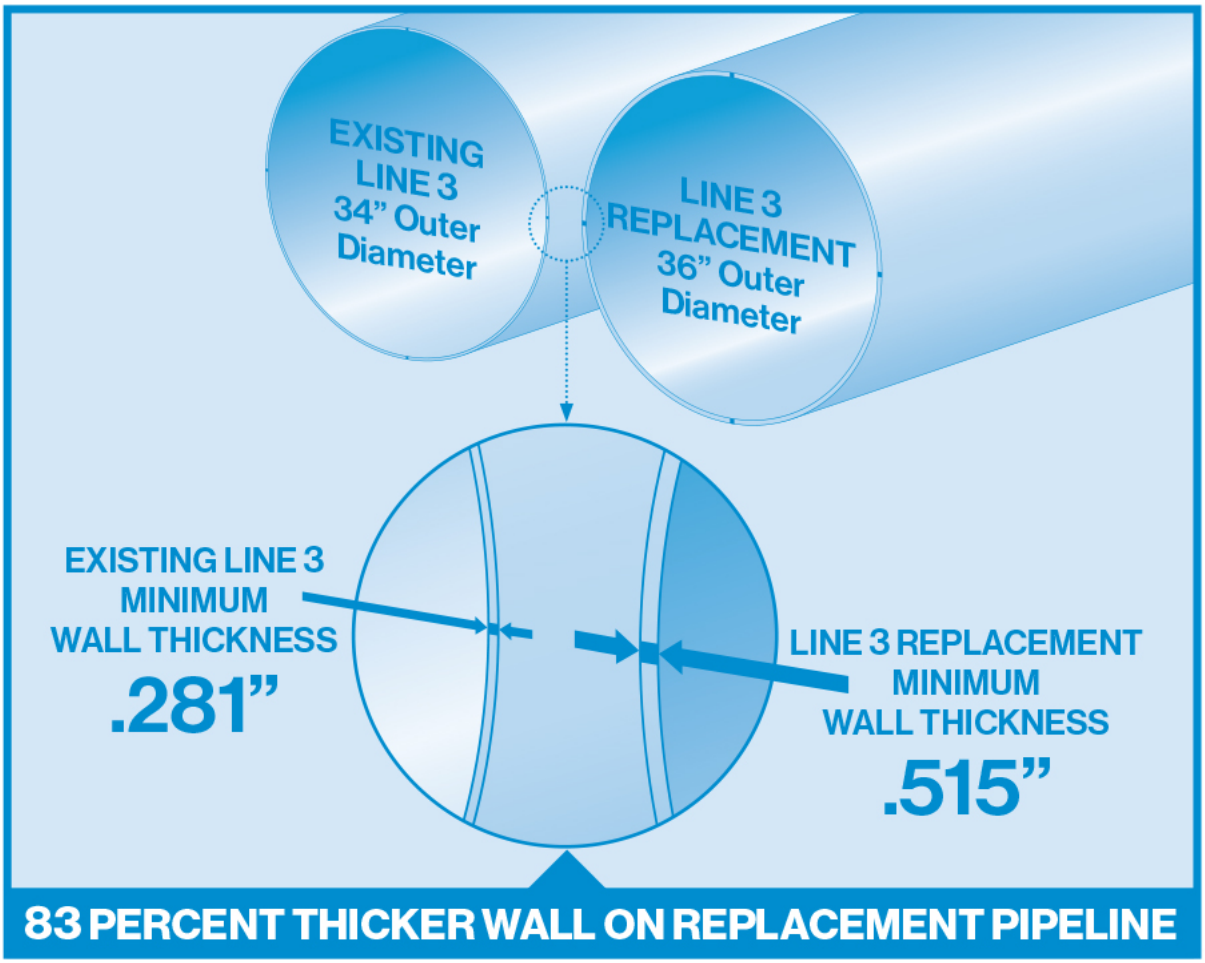
VII. INTEGRITY BENEFITS OF A NEW PIPELINE

Q. From an integrity perspective, what are the benefits of a new pipeline, as compared to the existing Line 3?

A. Overall, a new pipeline provides the opportunity to restore Line 3 to its original operating capabilities utilizing modern materials, and current design and construction techniques. Specifically, the benefits of new pipeline include:

- Increased reliability and significant reduction in the number of integrity digs required as part of ongoing maintenance. The reduction in integrity digs also decreases disruptions to the environment and landowners, and decreases the temporary capacity reductions required to ensure safety while working around an exposed pipeline.
- Baseline ILI of new pipe can be conducted to allow a direct assessment across the entire length of the new pipe at the start of its life. Such a baseline assessment could not be performed when Line 3 was originally built because the ILI technology did not exist at that time. Having a baseline inspection allows for better detection of changing anomalies.
- Pipe replacement allows Enbridge to leverage up-to-date pipeline design, manufacturing and coating processes, and knowledge of environmental and social factors that has been acquired over the 60+ years of operating history in this area.

- The replacement pipeline for Line 3 will be constructed using thicker-walled pipe to handle greater pressure cycles and manage more variation in throughput demand. Primary wall thickness on existing Line 3 is 0.281 inches, while the new Line 3 pipe would primarily be 0.515 inches thick. As a result, the design will resist fatigue growth of cracks from pressure cycling. A comparison of the nominal (minimum) wall thickness of the existing Line 3 and proposed Line 3 is shown in the figure below.



- Pipe replacement is an opportunity to phase out known deficient pipe characteristics from pipelines that are in operation and utilize modern design, such as fusion bond epoxy coating ("FBE").

VIII. CONCLUSION

Q. To summarize your testimony, why is Enbridge proposing to replace Line 3?

A. The integrity condition of Line 3 was a key consideration that led Enbridge to analyze long-term solutions for continued safe operation of Line 3. As discussed earlier in my testimony, factors weighing in favor of replacing Line 3 include:

- The extent of existing corrosion is significant – Line 3 has the largest corrosion anomaly density in the Enbridge system. To fully address external corrosion issues, it would be necessary to remove and replace all of the dis-bonded PE-tape coating, which would not be accomplished through the current dig and repair program.
- The extensive corrosion, SCC, and long-seam cracking will require thousands of integrity digs across the entire line over the coming decades, with the associated year-after-year landowner and environmental impacts.
- It is not feasible to restore the original operating capacity of Line 3 with a continued dig and repair program. As a result, Line 3's operational flexibility is significantly limited, as is its ability to meet customer needs.

Replacement is required by the proposed Consent Decree, supported by Enbridge's shippers, and the best solution to address Line 3's time-dependent integrity threats and restore its original operating capabilities.

Q. Does this conclude your testimony?

A. Yes.

Laura Harms Kennett, P.Eng., MSc, PMP

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PROFESSIONAL EXPERIENCE

Manager/Supervisor Pipeline Asset Integrity Projects **March 2014 - Current**
ENBRIDGE PIPELINES INC. – LIQUIDS PIPELINES EDMONTON, ALBERTA

- Leading 5-9 engineers and analysts in enhancing the safety, reliability and sustainability of large-diameter, national and international hazardous liquid pipelines through prudent asset management and carefully selected integrity projects.
- Sponsoring pipeline risk-reduction projects including pipeline replacements, remediation of geological and hydrological threats, hydrostatic tests of in-service pipelines, remediation of cased crossings, cathodic protection system replacements and upgrades, and replacement of inline inspection tool traps.
- Developing annual capital budgets up to $150 million per year and 10-year long range plans.
- Communicating pipeline integrity science and management principles to internal and external stakeholders including regulators, landowners, indigenous peoples and the public.

Supervisor, Engineering Services, Mid Continent Region **2012 – 2014**
Senior Region Operations Engineer **2012**
ENBRIDGE PIPELINES INC. – LIQUIDS PIPELINES CUSHING, OKLAHOMA

- Led a team up to twelve personnel on regional engineering projects and programs associated with pipeline safety, integrity, reliability and compliance
- Developed, coordinated and executed operations engineering activities for an large bore oil pipeline system from Illinois to Oklahoma as well as four tank terminals including the largest oil storage facility in Cushing, OK (20 million barrels)
- Managed a department budget of $2MM and capital budgets of $75MM spread over 130 distinct projects and initiatives
- Led safety and equipment failure investigations using the DNV/SCAT methodology
- Designate Planning Section Chief (PSC) on the region's Emergency Response Team
- Represented the Region on company-wide technical committees including the Regional Services Technical Committee (RSTC) and the Leak Reduction Team (LRT)

Pipeline Integrity Program Manager **2009 - 2011**
ENBRIDGE PIPELINES INC. – LIQUIDS PIPELINES EDMONTON, ALBERTA

- Planned, coordinated and supervised pipeline inspection, cleaning and inhibitor programs
- Coordinated and sponsored pipeline repair programs and provided technical support to dig crews and non-destructive assessment technicians
- Implemented mitigative actions including pressure restrictions to ensure pipeline safety
- Managed budgets and prepared budget submissions
- Oversaw an aggressive inline inspection program following the Line 6B release in Michigan
- Co-chaired the annual Enbridge Pipeline Integrity Conference for 2010 and 2011, which unified over 75 staff from across Enbridge's system in Pipeline Integrity initiatives..

Project Engineer **2007 – 2009**
ENBRIDGE PIPELINES INC. - MAJOR PROJECTS EDMONTON, ALBERTA

- Managed budgets, schedules and mechanical work scopes for the $0.8 billion Hardisty Merchant Tanks project, with a primary focus on pipeline connections to third-party companies, cathodic protection systems, and pipeline coating applications
- Compiled technical information for regulatory reports and interconnection agreements with third-party companies
- Reviewed drawings from the engineering contractor for compliance with specifications, codes and standards, opportunities for cost reductions, and operability of the designs
- Developed the facility oil-fill plan and oversaw the execution of the plan to fill 19 tanks and all related meters and manifolds
- Involved with the collaborative design of the pipeline interconnections in existing facilities

Technical Specialist **2007**
LOCKERBIE & HOLE INC. FORT MCMURRAY, ALBERTA

- Provided engineering support during an intense 6-week, 13-hours/day plant shut-down at the Suncor oilsands plant
- Tracked and reported construction progress and estimated extra work costs
- Ensured client specifications, codes and standards were maintained

Field Piping Coordinator **2006**
TIC CANADA FORT MCMURRAY, ALBERTA

- Provided technical support to a multi-discipline contractor at the CNRL Horizon oilsands site
- Investigated field construction engineering problems and worked with the owner's representatives to develop amicable solutions

Environmental Technologist **2002 - 2005**
Mechanical Engineering Technologist **2000 - 2002**
ALTASTEEL LTD. EDMONTON, ALBERTA

- Interpreted, reviewed, and incorporated environmental legislation into operations procedures
- Authored energy efficiency and environmental reports for submission to legislating bodies and industrial associations
- Researched and applied environmentally responsible techniques for energy reduction, pollution control, waste recycling, and hazardous material removal (mold and asbestos)
- Coordinated water, soil, and air monitoring programs
- Provided technical support to maintenance and operations personnel
- Managed in-house capital projects from conceptual design to commissioning
- Resolved operational problems by modifying or replacing existing equipment
- Supervised trades people and subcontractors while ensuring safe work practices
- Represented AltaSteel on the Strathcona Industrial Association Environmental Committee
- Part of a team that designed and constructed a $25M bar mill expansion

EDUCATION

Masters of Science in Engineering and Technology Management **2012 – 2015**
OKLAHOMA STATE UNIVERSITY STILLWATER, OKLAHOMA

Mechanical Engineering, B.Eng. **2005 – 2007**
LAKEHEAD UNIVERSITY THUNDER BAY, ONTARIO

Environmental Resource Management, Certificate **2002 – 2005**
UNIVERSITY OF ALBERTA EDMONTON, ALBERTA

Mechanical Engineering Technology, Diploma (with honors) **1997 - 1999**
NORTHERN ALBERTA INSTITUTE OF TECHNOLOGY EDMONTON, ALBERTA

CURRENT PROFESSIONAL AFFILIATIONS and VOLUNTEER POSITIONS

- Energy Futures Lab (Non-profit organization in Alberta, Canada)
  - Fellow since 2017
- Human Venture Leadership (charitable organization delivering human venture learning programs)
  - Board member since 2016
- Project Management Institute (PMI)
  - Project Management Professional (PMP) since February 2012
- Association of Professional Engineers and Geoscientists of Alberta (APEGGA)
  - Professional Engineer (P.Eng.) registered in Alberta
- American Society of Mechanical Engineers (ASME) member
- Northern Alberta Female Hockey Association
  - Hockey team manager since 2014

Pipeline Integrity ILI and Repair Process

Long-Term ILI Selection and Scheduling (5-10 year Forecast)

Develop Run Plan with Vendors (Year Prior)

Manage Preparatory Activities and Work Order Issuance

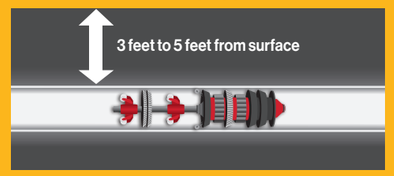
Draft Pre-launch Plan (> 30 days Prior)

Final Pre-launch Plan (> 15 days Prior)

Pre-job Safety Meeting

Tool Launch (Duration: 1-3 days)

In-line Tool



Retrieve and Clean Inspection Tool (Receipt Date)

Data Quality Assessment (< 48 hours of Receipt Date)

De-mobilize Inspection Tool and Crew

Priority Notification Report (< 7 days)

Preliminary Reports (< 60-120 Days)

Final Report (< 180 Days from Receipt Date)

Dig Issuance

Dig Planning: Permitting, Site Access, etc.

Excavation and Cleaning

Field Assessment

Typically, the area of the excavation is stripped of topsoil, which is stored separately from the subsoil. After the pipeline is excavated, the pipe coating is removed so the pipeline can be inspected. If needed, any repairs will be made and the pipeline (and coating) will be restored to proper condition.

Data Correlation and Performance Tracking

Repair and Re-coat (< 30-365 Days from Dig Issuance)

Re-bury Pipe, Restore Site and De-mobilize

Site Monitoring (> 1 year)

Integrity Dig Steps

Figure 3.4.3-1

Identify dig site and strip topsoil where applicable

Excavate to expose the pipe

Clean the exposed pipe

Inspect the pipe

Repair the pipe segment, as necessary

Re-coat the pipe

Backfill excavation and cleanup

Restoration

Restored right-of-way