

# FINAL REPORT

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## Review and Assessment of Technical Evaluation for Enbridge Line 9B Reversal

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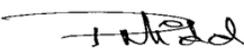
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## TABLE OF CONTENTS

Section	Page
1. Introduction.....	1
2. Mandate .....	2
2.1. Document Review .....	2
3. Objectives.....	6
4. Background.....	7
4.1. Pipeline Specifications .....	9
4.2. Proposed Changes to Existing Facilities .....	10
4.3. Proposed Hydraulic Design .....	11
5. Approach .....	12
6. Analysis .....	15
6.1. Review of Pipeline Threats.....	15
6.1.1 Metal Loss .....	15
6.1.1.1 External Corrosion.....	15
6.1.1.1.1 Coating Type.....	16
6.1.1.1.2 Age .....	16
6.1.1.1.3 Coating Condition .....	17
6.1.1.1.4 Cathodic Protection Effectiveness .....	18
6.1.1.1.5 Operating Stress Level .....	18
6.1.1.1.6 Assessment Practices .....	19
6.1.1.2 Internal Corrosion .....	20
6.1.1.2.1 Product Stream Composition .....	21
6.1.1.2.2 Flow Characteristics .....	23
6.1.1.2.3 Mitigation Practices .....	23
6.1.1.2.4 Assessment Practices .....	23
6.1.1.3 Erosion.....	24
6.1.2 Cracking.....	24
6.1.2.1 Technology Limitations of Assessment Techniques .....	26
6.1.2.1.1 Hydrostatic Testing .....	27
6.1.2.1.2 In-Line Inspection .....	31
6.1.3 External Interference .....	32
6.1.3.1 Damage Prevention Program.....	33
6.1.3.2 Damage Detection Program.....	34
6.1.4 Material and Manufacturing Defects .....	35
6.1.5 Construction Damage.....	36



6.1.6 Geotechnical / Hydrological Hazards ..... 37

    6.1.6.1 Slope Management Program ..... 37

    6.1.6.2 Pipeline Movement Management Program ..... 38

    6.1.6.3 Water Crossing Management Program ..... 38

6.1.7 Equipment Failure..... 39

6.1.8 Other Causes..... 39

7. Summary and Recommendations ..... 42

    7.1. Metal Loss ..... 42

        7.1.1 External Corrosion ..... 43

        7.1.2 Internal Corrosion ..... 43

            7.1.2.1 Impacts of Product Stream Composition and Flow Rates..... 44

            7.1.2.2 Conclusions and Recommendations..... 45

        7.1.3 Erosion ..... 46

    7.2. Cracking ..... 46

    7.3. External Interference ..... 48

    7.4. Materials and Manufacturing Defects ..... 49

    7.5. Construction Damage ..... 50

    7.6. Geotechnical / Hydrological Hazards..... 51

    7.7. Equipment Failure ..... 52

    7.8. Other Causes ..... 53

**ATTACHMENTS**

- Attachment A: Crack Detection and Analysis Using In-Line Inspection**
- Attachment B: Dynamic Risk Review and Assessment of Enbridge Line 9B RECOMMENDATIONS Vs. NEB Section 58 Order XO-E101-003-2014 CONDITIONS**



## Glossary of Terms and Abbreviations

AFD	Axial Flaw Detection – a type of electronic in-line inspection tool that utilizes magnetic flux leakage technology to detect axial flaws. Unlike conventional magnetic flux leakage tools, where a magnetic field is induced in the pipe in a pipe-axial orientation, the magnetic field that is induced in AFD tools is circumferentially-oriented. While this tool is optimally designed for the detection of axially-oriented areas of wall loss (such as axially-oriented corrosion), it can also detect axially-oriented crack-like features, provided that there is sufficient crack opening (typically cited as approximately 0.2 mm). See also CMFL.
Caliper	A type of electronic in-line inspection tool that is designed to identify, locate and measure pipe deformation, including ovality, wrinkles, buckles, and dents
CGR	Corrosion Growth Rate
CMFL	Circumferential Magnetic Flux Leakage – an alternative term for Axial Flaw Detection (AFD) in-line inspection tools.
Couplant	A fluid that is used to transmit ultrasonic impulses between an electronic transducer and the object being inspected. While some form of couplant is generally needed in order to perform internal inspections of gas pipelines when using traditional ultrasonic technology, couplant is not normally required in liquids pipelines, since the liquid product being transported acts as a couplant.
CP	Cathodic Protection - a technique used to control the corrosion of a metal surface by making it the cathode of an electrochemical cell
Critical	(as used in reference to a pipe defect) – a critical pipe defect is one that is sufficiently large to cause a failure at the operating stress level
CSA	Canadian Standards Association
CSA Z662-11	Canadian Standards Association Z662-11, Oil and Gas Pipeline Systems



Dent	A depression caused by mechanical damage that produces a visible disturbance in the curvature of the wall of the pipe or component without reducing the wall thickness
Deterministic	(as used in the term 'Deterministic Analysis') - a form of analysis that provides a prediction of an outcome without assigning any probabilities to that outcome. When used in pipeline failure modeling, a deterministic analysis will predict the outcome as either 'failure' or 'no failure'. This is as opposed to a reliability analysis, which assigns a probability of occurrence to each outcome (see also 'Reliability').
Dilbit	Diluted bitumen – an oil blend made from bitumen and a diluents, usually condensate, for the purposes of reducing the viscosity of the bitumen to pipeline viscosity and density specifications
DRA	Drag Reducing Agent – a polymer additive which acts to reduce turbulence in oil pipelines. The use of drag reducing agents can allow for oil to either be pumped through at lower pressures or a larger volume of oil to be pumped without causing a change in pressure
DSAW	Double Submerged Arc Welding – an arc welding process that employs a consumable filler metal submerged in a granular flux as it is melted by an electrical arc
D/t	The ratio of a pipe's outside diameter to its wall thickness
EA	Engineering Assessment - a documented assessment of the effect of relevant variables upon fitness for service or integrity of a pipeline system, using engineering principles, conducted by, or under the direct supervision of, a competent person with demonstrated understanding and experience in the application of the engineering and risk management principles related to the issue being assessed
EMAT	ElectroMagnetic Acoustic Transducer – a type of electronic transducer that is employed on some forms of electronic inline inspection tool. EMAT transducers act to generate acoustic impulses in pipe being inspected, which, when reflected back from flaws, can be detected and interpreted.



Excavation Report	A document that records the results of any in-the-ditch inspection, including findings of coating condition, corrosion products observed, and the presence, precise location and dimensions of any flaw(s) observed. Excavation Reports are often generated as a result of investigations performed subsequent to in-line inspections.
Fracture	Failure of a material that is characterized by brittle through-wall extension of a crack that occurs when the stress intensity in the vicinity of a flaw tip exceeds the fracture toughness of the material
Hazard	A condition or event that might cause a failure or damage incident or anything that has the potential to cause harm to people, property, or the environment
Hydrotest	Also referred to as hydrostatic pressure test - a way to test a pipeline for strength and leaks. The pipeline is filled and pressurized with water, for an amount of time and monitored for leaks, ruptures, or changes in shape. Hydrotesting is intended to confirm the structural integrity of the piping, and is used as the basis for establishing its maximum operating pressure.
ILI	In Line Inspection – a form of inspection using electronic tools that pass through a pipeline and record information related to dimensions, flaws, and position.
ILI Log	A listing of all features recorded during an in-line inspection, including wall thickness changes, weld locations, flaw characterization by type, flaw location (both axial and o'clock position), flaw depth, and flaw length
IMU	Inertial Mapping Unit – a type of electronic in-line inspection tool that utilizes on-board gyroscopes to map the position and orientation of a pipeline in three-dimensional space
IR	Information Request (typically issued to an applicant as part of a hearing)
Line 9B	The segment of Enbridge's Line 9 between North Westover Station, in Ontario to the Montréal Terminal in Québec.
Ligament	(as used in the phrase 'remaining ligament') that portion of the through-wall cross-section of a flaw that is still intact



MFL	Magnetic Flux Leakage – a type of electronic in-line inspection tool that detects volumetric metal loss by inducing a magnetic field in the pipe, and measuring magnetic flux leakage at volumetric discontinuities through the use of Hall Effect sensors.
ML-CD	The segment of Line 9B between Montréal Terminal, in Québec (ML) and Cardinal Station, in Ontario (CD)
MOP	Maximum Operating Pressure – the limit of pressure at which piping or equipment can be operated. The limits may be imposed by a variety of constraints, such as design specification, hydrostatic test pressure limits, physical limits of the materials, operating characteristics of the line, and the capacity of pumps. The MOP may vary from section to section, or elevation to elevation in a given pipeline. Typically, “maximums” for pipeline systems are determined as being measured from the downstream end of the mainline pump, and all other MOPs for all sections of the downstream mainline pump are based on that initial value.
NDE	Non Destructive Examination – any of a variety of inspection techniques, utilizing a broad range of technologies for the purposes of flaw detection without damaging the object being inspected
NEB	National Energy Board
NPS	Nominal Pipe Size – the outside diameter of a pipe, expressed in inches
OD	Outside Diameter
Operating Stress	The hoop stress developed in a pipe by operating pressure, and is determined as the product of pressure and diameter, divided by the wall thickness.
POD	Probability of Detection – the statistical likelihood that an assessment technique will identify the presence of a feature that exceeds the published detection threshold of the assessment technique
Reliability	In failure modeling and analysis, reliability is defined as the inverse probability of failure [i.e., $R = 1 - P_f$ , where, $R$ represents reliability (expressed as a fractional probability), and $P_f$ represents failure probability (also expressed as a fractional probability)]. In the above



reliability expression, the term ‘failure’ is applied to an engineered component or structure, and is defined as the failure of that component or structure to perform on demand. For pipelines, the term ‘failure’ is commonly used to represent a loss of containment (i.e., leak or rupture). Reliability analysis is a form of stochastic analysis that employs statistical techniques to establish the likelihood of failure (and hence reliability), expressed as a probability.

RPR	Rupture Pressure Ratio – predicted failure pressure of a corrosion feature divided by the pressure at the pipe’s specified minimum yield strength
SCC	Stress Corrosion Cracking – any of a variety of forms of environmental cracking mechanisms that occur in steel arising from the combination of stress in conjunction with specific environmental conditions.
SMYS	Specified Minimum Yield Strength – the internal pressure that corresponds to a stress level at which a pipe material reaches its nominal yield strength
S&W	Sediment and Water – the combined solid sediment plus water content of a liquid product, expressed as a percentage
UltraScan CD	The trademarked name of a GE in-line inspection tool that is designed for crack detection using shear-wave ultrasonic flaw detection techniques
USCD	An abbreviation for GE’s UltraScan CD tool
UltraScan WM	The trademarked name of a GE in-line inspection tool that is designed for wall measurement (and hence, the ability to detect volumetric wall loss features, such as corrosion). The UltraScan WM tool uses compression-wave ultrasonics for wall measurement.
UT	Ultrasonic inspection testing – a type of non-destructive testing that utilizes ultrasonic technology for the detection of flaws
wt	Wall Thickness (in reference to pipe)

## **1. Introduction**

Enbridge Pipelines Inc. (Enbridge) has recently received conditional approval from the National Energy Board for the reversal of a segment of Line 9 between North Westover, Ontario and Montréal, Québec. In January, 2014, the Government of Québec engaged Dynamic Risk to undertake an independent evaluation of the integrity of the Enbridge Line 9B pipeline. The result of this evaluation, which is reported on herein, focused solely on the Québec portion of Line 9B, which extends from the Québec-Ontario provincial border, near Peveril (Québec), to Montréal East (Québec).

The evaluation consisted of a thorough review of the Enbridge's "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment" (the 'Enbridge Pipeline Integrity Engineering Assessment') as well as other publicly available documents related to the Line 9B reversal project. In addition, a request was made to Enbridge for information related to the integrity assessment of Line 9B within the Province of Québec, and this information was included in the evaluation.



## 2. Mandate

As defined within the Mandate Document issued by the Government of Québec, the mandate required an independent and thorough review of the Enbridge Pipeline Integrity Engineering Assessment and other related documents, and the drafting of a concise report that includes the following:

1. Verification that the inclusion of information on changes in the composition and volume of the transported crude oil and the impacts of using drag reducing agents on the pipeline have duly been taken into consideration in the Enbridge Pipeline Integrity Engineering Assessment;
2. Verification that the basis and parameters of the Enbridge Pipeline Integrity Engineering Assessment ensure the safety of the operation of line 9 and that the integrity program meets the best safety standards in order to ensure safe use of the pipeline in Québec
3. Lastly, if necessary, the report will make concrete recommendations for improving the inspection and maintenance program to meet the highest possible safety standards and ensure safe use of the pipeline.

### 2.1. Document Review

The Mandate Document listed the following documents to be included in the evaluation:

1. The Enbridge Pipeline Integrity Engineering Assessment (NEB OH-002-2013 Document # B1-15);
2. Schedule A of the Enbridge Pipeline Integrity Engineering Assessment (NEB OH-002-2013 Document # B1-16);
3. Schedule B of the Enbridge Pipeline Integrity Engineering Assessment (NEB OH-002-2013 Document # B1-17);
4. Enbridge Document “Line 9B Reversal and Line – Capacity Expansion Project Facilities Integrity Engineering Assessment” (the “Enbridge Facilities Integrity EA Document”) NEB OH-002-2013 Document # B1-18);
5. National Academy of Science – TRB Special Report 311: “Effects of Diluted Bitumen on Crude Oil Transmission Pipelines” (ISBN 978-0-309-28675-6);
6. Requirements of the *National Energy Board Onshore Pipeline Regulations* – SOR/99-294, as amended, and the CSA Z662 standard – *Oil and Gas Pipeline Systems*, of the Canadian Standards Association

In addition to the above, the Mandate Document listed the following documents to be included in the evaluation:

- Results and findings of integrity assessment anomaly detection data provided by 3<sup>rd</sup> party in-line inspection service providers;
- Updates and responses to requests for information about the Enbridge Pipeline Integrity Engineering Assessment; and,
- Any other documents or information considered relevant, including the preliminary results of the integrity work carried out in 2013

The information that is available in the public domain as part of the National Energy Board's Hearing NEB OH-002-2013 was quite extensive, and a list of all documents that were reviewed is contained in the References Section at the end of the report. Subsequent to reviewing the available information, requests for additional information were submitted to Enbridge. These requests included the following:

- Requests for clarification at various locations of the Pipeline Integrity Engineering Assessment, as well as other documents;
- ILLI Logs for the 2012 in-line inspections of the ML-CD segment
- Excavation Reports performed subsequent to the 2012 in-line inspections
- Details regarding operating conditions following the conversion
- Details regarding the changes in product stream associated with Enbridge's application
- Details regarding Enbridge's remaining life calculations
- Details regarding the crack growth models used by Enbridge in its analysis
- Information regarding measures taken to improve probability of detection and reduce false-negatives

The responses that were received from Enbridge were primarily oral presentations of information, occurring during the course of information-gathering meetings held with Enbridge Subject Matter Experts. No information was provided in response to the requests made for the ILLI logs from the 2012 in-line inspections, or to the excavation reports relating to those inspections, as this information is considered by Enbridge to be proprietary in nature. Nevertheless, it is understood that Enbridge will be issuing an engineering assessment addressing the analysis of the 2012 in-line inspections and the information obtained from the associated excavations. Three of the National Energy Board's 30 conditions are related to the analysis and findings from these data, as outlined below:



- Condition #9:

Enbridge shall file with the Board, at least 90 days prior to applying for leave to open (LTO), an Updated Pipeline Engineering Assessment (Updated EA) in a similar format to that of the Line 9B Engineering Assessment. The Updated EA shall be based on the in-line inspections (ILI) and excavations that Enbridge has performed on Line 9 in 2012 and 2013 from Sarnia Terminal to Montreal Terminal. The Updated EA shall include, but not be limited to:

  - a) a remaining life analysis, taking into account coincident features, demonstrating that the pipeline between Sarnia Terminal and Montreal Terminal is fit-for-service in the reversed flow direction at Board approved maximum operating pressures (MOPs). If Enbridge chooses to apply different operating pressures for this analysis a justification must be provided;
  - b) a pipeline predicted Rupture Pressure Ratio analysis for integrity threats (including coincident threats) using 100% of the Specified Minimum Yield Strength as reference;
  - c) ILI tool performance, including their probability of detection and probability of sizing;
  - d) Field-tool unity plots for crack and corrosion, including for depth and length; and
  - e) Results of the 2012 annual survey of the cathodic protection system.
- Condition 27:

Enbridge shall file with the Board, within 18 months following the receipt of Board approval for LTO, a proposed long-term integrity improvement plan to mitigate and monitor remaining ILI-reported corrosion (internal and external), geometry and cracking features in the pipeline sections between North Westover Station and the Montreal Terminal indicating, but not limited to, their timelines, the rationale for selecting those features, and the planned re-inspection interval.
- Condition 28:

Enbridge shall file with the Board for approval, within 18 months following the receipt of Board approval for LTO, an updated Deterministic Remaining Life evaluation for each segment (i.e., pump station to pump station) of Line 9 from the Sarnia Terminal and the Montreal Terminal. This assessment should take into account (but not be limited to) the results of the most recent ILI runs and excavations, coincident imperfections, the Board approved MOPs, and actual operating pressure cycling dataset for the most aggressive periods since the reversal.

A fourth condition (Condition 19) will rely on the analysis of the 2012 in-line inspection data, and the engineering assessment that is based on that analysis in order to develop a plan to manage cracking features:

- Condition 19:  
Enbridge shall submit to the Board, prior to applying for LTO, a plan to manage cracking features in the pipeline section between Sarnia Terminal and Montreal Terminal. This plan must include the timeline associated with the assessment methodology, and the rationale for selecting the timeline.



### 3. Objectives

Within its Mandate Document, the Government of Québec lists the objectives of the independent evaluation reported on herein as follows:

1. Check if Enbridge inspection and maintenance techniques meet the industry's highest standard and ensure the pipeline's integrity;
2. Check if specific and adequate measures are being taken to minimize the risk of incidents near sensitive areas, especially watercourses;
3. Check if the effects on the pipe resulting from the reverse flow and a change in the composition of transported oil and volumes were evaluated properly; and,
4. Assess the relevance of performing a hydrostatic test prior to the pipeline inversion.

## 4. Background

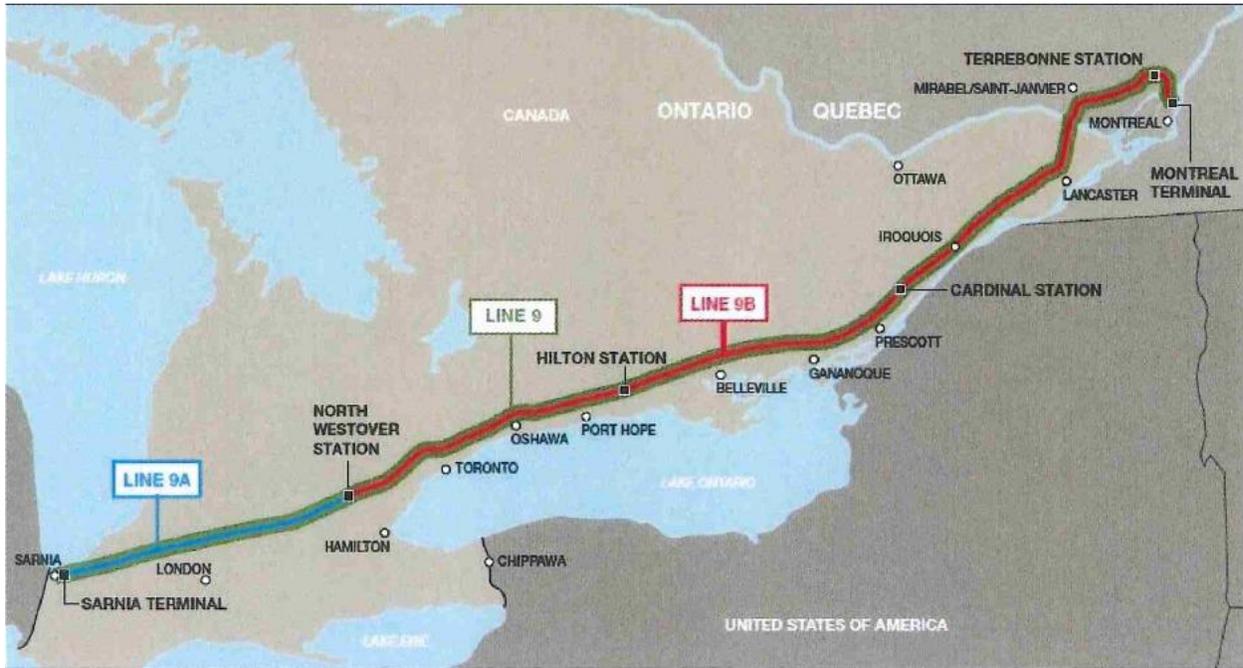
In March, 2014, Enbridge received approval (subject to conditions) from the National Energy Board under section 58 and under Part IV of the National Energy Board Act for:

1. Flow reversal of the segment of the 639 km-long Line 9 between North Westover, Ontario and Montréal, Québec, (“Line 9B”).
2. Expansion of the entire Line 9 capacity from Sarnia, Ontario to Montréal
3. Revision to the Line 9 Rules and Regulations Tariff to allow transportation of heavy crude.

Collectively, the above three changes constitute what is referenced throughout this report as Enbridge’s proposed conversion of Line 9. One of the primary focus areas of this study is to identify material differences in failure susceptibility between the existing operations and the proposed conversion.

Line 9 is an existing Enbridge 762 mm (NPS 30) diameter pipeline with a current capacity of approximately 38,157 m<sup>3</sup>/day (240,000 barrels per day (“bpd”)), extending from Sarnia, Ontario to Montréal, Québec. A map showing the facilities involved in this application is shown in Figure 1.

**Figure 1**  
**Facilities Involved in Enbridge Line 9B Reversal and Line 9 Capacity Expansion Project**



Line 9 was placed into service in 1976 and originally flowed in an eastward direction. The pipeline was deactivated for two years from July, 1991 to July 1993, during which period, the pipeline was purged with nitrogen and cathodically protected. The flow of the pipeline was reversed to a westward direction in 1999 following the National Energy Board (NEB) OH-2-97 proceeding and pursuant to Order XO-J1-34-97. Currently, the pipeline transports condensate, sweet and sour crude oil from areas such as the North Sea, West Africa and the Middle East, in a westbound direction.

Enbridge has recently received NEB approval (subject to conditions) for the reversal of the 639 km-long section of Line 9 from North Westover Station to Montréal Terminal (“Line 9B”). In addition, Enbridge has received NEB conditional approval to increase the annual capacity of the entire Line 9 to approximately 47,696 m<sup>3</sup>/day (300,000 bpd), as well as to revise the Line 9 tariff to allow for the transportation of heavy crude on Line 9. The reversal of the flow of Line 9B will be achieved mainly by modifying existing facilities. The increased capacity will be achieved through the addition of pumps and skids that will inject Drag Reducing Agent (“DRA”) into Line 9 at existing Enbridge facilities. Project work at Sarnia Terminal, North Westover Station, Hilton Station, Cardinal Station (in Ontario), and Terrebonne Station and Montréal Terminal (in Québec) includes the modification or replacement of existing equipment and the installation of pumps and piping within the existing facility boundaries.



#### **4.1. Pipeline Specifications**

The following Table provides a summary of the pipe properties for Line 9B from North Westover Station to Montréal Terminal. The Maximum Operating Pressures (MOPs) approved by the NEB in the March, 1999 leave-to-open between Cardinal Station and Montréal Terminal range from 2,498 kPa to 4783 kPa. The operating pressures that are planned as part of the Line 9 Reversal and Line 9 Capacity Expansion Project will be consistent with those listed above.



**Table 1  
Pipe Properties for Line 9B**

Property	Value(s)
Diameter	NPS 30 (762 mm OD)
Wall Thickness	6.35 mm x 342.948 km 7.14 mm x 191.459 km 7.92 mm x 92.134 km 8.74 mm x 12.800 km 9.525 mm x 0.402 km 12.7 mm x 8.975 km
Grade	API 5L X52 (359 MPa)
Pipe Manufacturing Specification	CSA Z245.1-1971 and CSA Z245.2-1971
Construction Date	1975
Longitudinal Seam Weld Type	Double Submerged Arc Weld
Line Pipe Manufacturer	Stelco
External Line Pipe Coating	Single Layer Polyethylene Tape

The pipeline was initially hydrostatically tested in 1976 as part of commissioning to 1.25 x Maximum Operating Pressure. It was subsequently re-tested in 1997 as part of the flow reversal project. No test failures were reported during the 1997 hydrostatic re-testing program.

#### **4.2. Proposed Changes to Existing Facilities**

There are two stations associated with Line 9B within the Province of Québec; Terrebonne Station, and Montréal Terminal. The Line 9B facilities at Terrebonne Station were installed in 1999 as part of the conversion from the original west-east flow configuration to the current east-west flow configuration. Enbridge does not anticipate using the pumps at Terrebonne Station after completion of the conversion back to west-east flow configuration. At the Montréal Terminal, the receiving trap will be replaced and a surge vessel will be installed as part of the project, and additional unnecessary piping at the terminal will be removed.

Operating pressure is not being increased along with the increase in flow rate (which is being achieved through the use of Drag Reducing Agent (DRA)). The normal operating pressure at Terrebonne Station will not change, while the normal operating pressure at Montréal Terminal will decrease significantly (from 1,586 kPa currently, to 689 kPa post-conversion).



### 4.3. Proposed Hydraulic Design

The Project includes a proposed increase in the annual capacity of Line 9 from 38,157 m<sup>3</sup>/day (240,000 bpd) to 47,696 m<sup>3</sup>/day (300,000 bpd). The existing MOP of the pipeline will not change post reversal. The typical properties of the oil to be transported in Line 9B are shown below:

**Table 2**  
**Product Stream Properties in Enbridge Application**

Oil Type	Properties							
	Viscosity (cSt)		Density (kg/m <sup>3</sup> )		Temperature (°C)		Vapour Press (kPa)	
	Min	Max	Min	Max	Min	Max	Min	Max
Light Oil	2	20	800	876	7.5	18.5	0	80
Medium Crude	20	100	876	904	7.5	18.5	0	60
Heavy Crude	100	350	904	940	7.5	18.5	0	60



## 5. Approach

In order to respond effectively to the mandate, as outlined in Section 2, and achieve the objectives as outlined in Section 3, a threat-based analysis was undertaken, addressing the potential mechanisms of failure listed in Clause H.2.6.1 of CSA Z662-11, as follows:

1. Metal loss
  - a. Internal Corrosion
  - b. External Corrosion
  - c. Erosion
2. Cracking
  - a. Environmental cracking mechanisms, such as Stress Corrosion Cracking (SCC)
  - b. Fatigue cracking
  - c. Mechanically-induced cracking (such as through denting)
3. External Interference (i.e., external activities of first, second or third parties, causing damage to the pipeline)
4. Material or manufacturing defects in pipe or components
5. Construction damage or defects
6. Geotechnical / hydrological hazards
7. Failure of equipment (e.g., valves, seals, packing, gaskets), including ancillary equipment
8. Other causes, (control system malfunction, improper operation, or other causes, as identified)

This threat-based analysis was undertaken in consideration of the following information, derived from the sources outlined in Section 2.1:

- Design-related information
- Materials information
- Construction information
- Operating parameters (past and proposed)
- Flow properties and characteristics (past and proposed)
- Product stream composition (past and proposed)
- Operating history
  - Defect history, including mechanism of formation, growth and failure
  - Failure incidents
  - Hydrostatic re-test history
  - Inspection history and results
  - Maintenance and repair history
- Review of integrity data
- Review of threat assessments



- Review of Engineering assessments
- Review of Risk assessments
- Review of Information Requests

Although the scope of the mandate is limited to the segment of Line 9B that exists east of the Ontario / Québec border, the systemic nature of some threats is such that the above information was reviewed for the entire pipeline.

To address each threat, as well as those possible interactions between main threat categories, information listed above was reviewed in order to provide commentary on:

- i. Whether appropriate consideration of changes in composition, volume and direction of the transported crude oil and the use of DRA has been duly accounted for in Enbridge's assessments;
- ii. Whether the assessments performed by Enbridge have been adequate to ensure the safe operation of Line 9B;
- iii. Whether Enbridge's integrity program for Line 9B is representative of industry-leading practice; and,
- iv. Whether adequate measures are being taken to minimize the risk of incidents near sensitive areas, especially watercourses

With respect to Objective iii above, the phrase "industry-leading practice" was taken to be synonymous with the term "industry best practice", which is commonly understood to mean "a practice which is most appropriate under the circumstances, especially as considered acceptable or regulated in business; a technique or methodology that, through experience and research, has reliably led to a desired or optimum result".<sup>1</sup> This phrase does not therefore imply that an industry best practice is necessarily endorsed or specified by a specific industry standard or specification, as for many processes and procedures there are no prescribed criteria that are available in industry standards or specifications, against which these processes or procedures can be evaluated. In several locations throughout this report, commentary is provided as to whether a specific practice is representative of 'industry best practice' or 'industry leading practice'. These terms are used in the context of the above, and commentary regarding industry best practice or industry leading practice is provided in order to be responsive to Objective iii.

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<sup>1</sup> Dictionary.com definition.



Where warranted, specific recommendations are made, and a detailed analysis is provided to address the effectiveness of hydrostatic testing as a potential tool for enhancing pipeline integrity in consideration of the integrity management practices that are already being employed by Enbridge.

Collectively, the above commentary addresses the full scope of the mandate and the objectives, as outlined in Sections 2 and 3, respectively.



## 6. Analysis

### 6.1. Review of Pipeline Threats

#### 6.1.1 Metal Loss

Three forms of metal loss were evaluated; external corrosion, internal corrosion, and erosion. Because each is associated with a unique mechanism and set of threat factors, they are considered separately, below.

##### 6.1.1.1 External Corrosion

External corrosion is considered a universal threat for all buried carbon steel pipelines. To date, there has been one leak attributed to external corrosion on Enbridge Line 9B, occurring on a piece of 19 mm (3/4-inch) diameter densitometer return piping inside a station in 1993.<sup>2</sup>

There are two barriers for prevention and/or mitigation of external corrosion in an operating steel pipeline. The external coating system is the primary defense, and is intended to form a physical barrier between the steel and a potentially corrosive environment. Cathodic protection (CP) is considered a secondary defense, and it is used to protect the pipeline from corrosion at locations where the primary defense system (coating) has failed.

The potential for external corrosion-related failures to occur is primarily influenced by the following factors:

- External Coating type,
- Age,
- Coating condition,
- Cathodic protection effectiveness, and,
- Operating Stress Level

Beyond the monitoring and maintenance of cathodic protection systems, Enbridge also performs periodic in-line inspection surveys using metal loss detection technology to identify specific locations where external corrosion may have occurred.

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<sup>2</sup> While Table 3-2 of the Pipeline Integrity Engineering Assessment indicates two leaks attributed to external corrosion, both occurring in 1993, a correction was issued as part of the response to NEB IR 1.27, indicating that one of these was not in fact a leak, but rather a non-leaking corrosion defect.



The role that each of the above factors plays in consideration of the proposed pipeline conversion, and its potential to influence the likelihood of failure by means of external corrosion is summarized in the sections below.

#### **6.1.1.1.1. Coating Type**

Line 9B is externally coated with single-layer polyethylene tape. This is a common coating system for pipelines constructed in the 1970s, but is no longer in common use in pipelines constructed today. Polyethylene tape coating is susceptible to wrinkling and disbondment, especially in larger-diameter pipelines, where soil stress plays a large role, and where “tenting” of the polyethylene tape coating can occur over the raised double submerged arc pipe weld seam. Polyethylene tape coating can shield cathodic protection currents, preventing cathodic protection from being effective if ground water penetrates under disbonded coating. For this reason, for pipelines coated with this type of coating system, it is of particular importance that the wall loss in-line inspection program be managed in an effective way. Further discussion of the wall loss in-line inspection program is provided in Section 6.1.1.1.6.

While coating type is a consideration in the assessment of the susceptibility to external corrosion failures, it is not a factor that will be influenced in any way by the proposed pipeline conversion.

#### **6.1.1.1.2. Age**

External corrosion manifests itself as time-dependent wall loss, the rate of which is determined by the reaction kinetics of the electrochemical processes involved.

Line 9B was placed into service in 1976, and so is now 38 years old. Because the fundamental material properties of steel do not change appreciably with time, steel pipelines are normally designed with an indefinite design life, and it is common for pipeline operators to manage their assets as such by implementing integrity programs to address time-dependent degradation mechanisms such as corrosion. This strategy of indefinite operating life span is not unique to steel pipelines, and similar operating philosophies are applied to other types of steel structures, such as bridges and buildings.<sup>3</sup>

Indefinite operating life span is a realistic goal only if time-dependent defects can be preemptively identified and repaired. In practice, pipeline operators endeavor to achieve this goal

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<sup>3</sup> For example, the Brooklyn Bridge and the Flatiron Building, both still in service in New York City, are currently 131 and 112 years old, respectively.



through in-line inspection and cathodic protection monitoring. The effectiveness of Enbridge's cathodic protection monitoring and in-line inspection programs are discussed in Sections 6.1.1.1.4 and 6.1.1.1.6.

While age is a consideration in the assessment of the susceptibility to external corrosion failures, it is not a factor that will be influenced in any way by the proposed pipeline conversion.

#### **6.1.1.1.3. Coating Condition**

Coating degradation is influenced by time, temperature, and soil conditions. While above-ground survey methods exist to assess and monitor coating condition, these types of surveys can be of limited effectiveness in coating systems, such as polyethylene tape, that shield the flow of electric current.

For pipelines coated with such systems, coating condition can be inferred through a review of metal loss in-line inspection data, where external wall loss feature density is assessed as a measure of coating condition. In the Pipeline Integrity Engineering Assessment, external wall loss features from the 2004 UltraScan WM inspection were overlaid with those from the 2007 GE-P11 MFL inspection, and a total of 1398 external metal loss features were reported along the 206.4 km segment of the Montréal – Cardinal (ML-CD) section. This represents an average of one external metal loss feature every 148 m. Not all of these 1398 external metal loss features can reasonably be expected to be attributed to external corrosion, since many could be representative of pipe mill manufacturing features, such as grind marks or other surface imperfections such as scabs and slivers. Therefore, the estimate of 1 metal loss feature every 148 m is possibly a conservative estimate.

Based on past experience in reviewing the ILI logs of pipeline operators throughout North America, an average of 1 metal loss feature every 148 m is considered to be very low relative to common industry experience, and is not indicative of systemic or broad-based coating failure. On the contrary, it appears as though the coating is performing very well (at least as of 2007) by comparison with industry norms. Regardless, coating condition is a factor that will not be influenced in any way by the proposed pipeline conversion.



#### **6.1.1.1.4. Cathodic Protection Effectiveness**

Cathodic protection is a means by which pipeline operators impart electrical potentials to their pipelines that are more electro-negative than the native potential of steel; the objective being to maintain any exposed steel surfaces (such as would occur at breaks or ‘holidays’ in the external coating) at a passive potential, where corrosion will not occur. Industry standards have established an acceptable electrical potential criterion of -850 mV (“off”), relative to a standard Cu/CuSO<sub>4</sub> reference electrode. An alternative criterion that has been adopted by the industry is to demonstrate a minimum of 100 mv depolarization shift. Enbridge has reported that it employs both these criteria during annual cathodic protection surveys. At the time of writing of Enbridge’s Pipeline Integrity Engineering Assessment document, all but one of the 519 of the most recent cathodic protection readings that had been completed between North Westover Station and Montréal Terminal (NW and ML) met the -850 mV “off” criterion, with the one exception meeting the 100 mv depolarization shift criterion.

Based on a review of available information, it was concluded that Enbridge’s cathodic protection monitoring and maintenance practices meet the standards of industry best practices, recognizing the previously-stated limitations regarding the shielding effects of polyethylene tape coating. Nevertheless, this factor will not be influenced in any way by the proposed pipeline conversion.

#### **6.1.1.1.5. Operating Stress Level**

Failure of a pipeline through external corrosion can occur either by means of through-wall penetration of a corrosion defect, or by means of stress-overload of a remaining ligament of pipe wall. Through-wall penetration, especially for relatively short defects, has the potential to leak and is not materially affected by the operating stress level. In cases where external corrosion defects become deeper and longer, the mode of failure can be a rupture. A rupture is generally controlled by pipe diameter, wall thickness, material grade, operating stress level, and defect size, recognizing that longer and deeper areas of corrosion will fail at lower operating stresses.

Because the increase in flow rate associated with the proposed Line 9B conversion is not being achieved through an increase in operating pressure, the new operating conditions will not result in an increase in the propensity to failure.



#### **6.1.1.1.6. Assessment Practices**

Dating back to 1977, the ML-CD segment of Enbridge Line 9B has undergone a total of 10 wall loss measurement in-line inspections, with the most recent being in 2012.<sup>4</sup> This represents a significant number of inspections that reflects a degree of diligence. The Pipeline Integrity Engineering Assessment provided summaries obtained from an overlay of the 2004 UltraScan WM inspection with the 2007 GE-PII MFL inspection.

The analysis procedure used to evaluate wall loss data, including the excavation and repair criteria were detailed in the Pipeline Integrity Engineering Assessment, and an evaluation of these procedures and criteria was undertaken.

#### *Corrosion Growth Analysis*

Enbridge has reported that it has developed a corrosion growth rate (CGR) analysis to provide insight into the integrity condition of the pipeline and to support monitoring and mitigation planning activities, including the establishment of in-line inspection intervals. This was an area in which additional information was sought, and discussions were held with Enbridge subject matter experts in order to gain clarity. It was determined that CGR values are determined for a given corrosion feature by dividing its maximum depth by the number of years of service and multiplying this value by a safety factor. This safety factor, is a function of pipe vintage and coating type, and acts to effectively reduce the amount of time assumed for flaw growth, thereby increasing the corrosion growth rate. An 'offset error' is applied to the measured nominal size of each corrosion feature to account for tool measurement error, however this offset error does not factor into the calculation of the corrosion growth rate.

Reassessment intervals are established using the calculated growth rates by ensuring that no feature grows to a Rupture Pressure Ratio (RPR) value of lower than 0.9 (0.93 in HCAs) or a depth of 75% of wall thickness (Note that Rupture Pressure Ratio is defined as the predicted failure pressure of a corrosion feature divided by the pressure at the specified minimum yield strength of the pipe). Reassessment intervals are limited to 10 years at a maximum, however Enbridge anticipates 5-6 year reassessment intervals for Line 9B.

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<sup>4</sup> Although Table 4-1 of the Pipeline Integrity Engineering Assessment indicates a total of 6 wall loss in-line inspections in the ML-CD segment prior to the 2012 inspections, the response to NEB IR # 1.22 reports a revised history, showing 7 wall loss in-line inspections prior to 2012. Table 3-3 of the Pipeline Integrity Engineering Assessment indicates that three forms of wall loss in-line inspection were performed in this segment in 2012; a MFL inspection, a USWM inspection and an AFD inspection.



There are no prescriptive guidelines within the CSA Z662-11 that mandate corrosion growth rate and re-assessment interval analysis, and as such, the above practice seems reasonable and is representative of industry leading practice, based on familiarity with the integrity management practices of North American pipeline operators.

#### *Excavation and Repair Criteria*

Enbridge employs the following excavation criteria:

- Rupture Pressure Ratio (RPR) 1.0 or less;
- Maximum Depth of 50% wall thickness or greater

Upon excavation, all corrosion features that are confirmed to have an RPR value of 1.0 or less, as well as all features having maximum depths greater than or equal to 80% of wall thickness (or greater than 50% if associated with welds or weld heat-affected zones), and all wall loss features associated with cracks are repaired with full-encirclement sleeves, while all remaining features are recoated. These repair criteria and methods match those of CSA Z662-11 Clause 10.10 and 10.11, respectively.

#### *Facilities Assessment Practices*

Piping inside stations is largely not accessible to in-line inspection. In its Facilities Engineering Assessment, Enbridge reports that since 2005, several external inspections have been performed on station piping. Inspection locations are based largely on internal corrosion inspection criteria, and once the pipe is exposed, the external surface of the pipe is examined. A regular external corrosion monitoring program such as this is representative of industry best practice.

### **6.1.1.2 Internal Corrosion**

To date, there have been no leaks attributed to internal corrosion on Enbridge Line 9B. In the Pipeline Integrity Engineering Assessment, internal wall loss features from the 2004 UltraScan WM inspection were overlaid with those from the 2007 GE-P11 MFL inspection, and a total of 25 internal metal loss features were reported along the 206.4 km segment of the ML-CD section, representing an average of one internal metal loss feature every 8.3 km.

This is a very low feature density, and furthermore, a review of the orientation plot contained within the Pipeline Integrity Engineering Assessment indicated that the internal wall loss features did not have a preferential orientation towards the 6 o'clock pipe position, where internal corrosion would be expected. This suggests that the internal wall loss features that had been detected as of 2007 were most likely primarily associated with randomly-distributed



manufacturing imperfections, such as grind marks and surface imperfections rather than internal corrosion. Discussions held with Enbridge's subject matter experts have revealed that no internal corrosion has actually been observed during any pipe maintenance activity along Enbridge Line 9B.

Despite the above evidence, industry best-practice for threat assessment dictates that internal corrosion should be considered as a potential threat on any carbon steel pipeline that has the potential to transport free water entrained within its product stream. Enbridge's assessment of threat potential for internal corrosion on Line 9B is consistent with this practice.

The potential for internal corrosion-related failures to occur is primarily influenced by the following factors:

- Product stream composition,
- Flow characteristics, and,
- Adoption of appropriate mitigation practices

Beyond the adoption of internal corrosion mitigation practices, the primary means that Enbridge employs to manage the threat of internal corrosion-related failures is through the employment of regular in-line inspection, using metal loss detection technology.

The role that each of the above factors plays in consideration of the proposed pipeline conversion, and its potential to influence the likelihood of failure by means of internal corrosion is summarized in the sections below.

#### **6.1.1.2.1. Product Stream Composition**

Line 9B transports crude oils that contain trace amounts of potential corrosive materials such as water, suspended solids and bacteria. As acknowledged in Enbridge's Pipeline Integrity Engineering Assessment, this can lead to the development of local corrosive conditions if these materials are allowed to accumulate and persist over long periods of time.

Sediment and water is measured by the parameter 'S&W', and is expressed in terms of a percentage of the product stream. In its current configuration, the maximum permissible S&W value for Line 9B is 1.0%, however this will be reduced to 0.5% following conversion. This reflects the fact that crude oil sourced from offshore has a greater variability in S&W content. This reduction in S&W tariff values associated with the conversion is despite the increase in the amount of heavy oil that will be shipped following the conversion. The decrease in S&W content that is associated with the proposed conversion is positive with respect to anticipated internal corrosion performance.



Some controversy has existed regarding the corrosivity of diluted bitumen (also known as 'dilbit') relative to conventional crude oils. This controversy has spawned much investigation recently, culminating in several industry reports.<sup>5,6,7</sup> The findings of these various reports have been quite consistent, and as summarized in Reference 7:

- Diluted bitumen does not have unique or extreme properties that make it more likely than other crude oils to cause internal damage to transmission pipelines from corrosion or erosion
  - Diluted bitumen has density and viscosity ranges that are comparable with those of other crude oils;
  - It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and operating temperature;
  - The amount and size of solid particles in diluted bitumen are within the range of other crude oils and do not create an increased propensity for deposition or erosion;
  - Shipments of diluted bitumen do not contain higher concentrations of water, sediment, dissolved gases, or other agents that cause or exacerbate internal corrosion, including microbiologically influenced corrosion;
  - The organic acids in diluted bitumen are not corrosive to steel at pipeline operating temperatures
- Diluted bitumen does not have properties that make it more likely than other crude oils to cause damage to transmission pipelines from external corrosion and cracking or from mechanical forces;
- There is no evidence that operating temperatures and pressures are higher or more likely to fluctuate when pipelines transport diluted bitumen than when they transport other crude oils of similar density and viscosity; and,
- Pipeline operating and maintenance practices are the same for shipments of diluted bitumen as for shipments of other crude oils

With respect to the use of Drag Reducing Agents (DRA), it should be noted that the use of drag-reducing agents is not specific to dilbit transportation. Their use is based on the operational requirements of a particular pipeline segment and throughput required. Drag Reducing Agents

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<sup>5</sup> Been, J. for Alberta Innovates Technology Futures, "Comparison of the Corrosivity of Dilbit and Conventional Crude", September, 2011.

<sup>6</sup> Canadian Energy Pipelines Association State of the Art Report, "Dilbit Corrosivity", Penspen Report # 12671-RPT-001, February, 2013

<sup>7</sup> TRB Special Report 311, "Effects of Diluted Bitumen on Crude Oil Transmission Pipelines", National Research Council of the National Academy of Sciences, 2013.



consist of long-chain polymers, and they act to dampen turbulence at the interface between the crude oil and the pipe wall to reduce friction and enable increased flow velocity. Drag Reducing Agents themselves are not corrosive, and the authors are unaware of any instances where the use of Drag Reducing Agents were shown to have been instrumental in the promotion of corrosion, or where their use led to the failure of an operating pipeline.

#### **6.1.1.2.2. Flow Characteristics**

One of the biggest threat factors for internal corrosion is intermittent flow, where water and sediment can drop out and accumulate at the bottom of the pipe. As indicated in Enbridge's Facilities Engineering Assessment, Line 9B currently operates in a start/stop mode of operation, with the frequency of the start/stop operation being dependent on the product availability and shipper needs. Following the conversion, Line 9B will be in continuous operation. This change in flow characteristics has a net positive effect on corrosivity.

#### **6.1.1.2.3. Mitigation Practices**

As summarized in its Pipeline Integrity Engineering Assessment, and in its response to various Information Requests, it is Enbridge's practice to assess pipeline operation for the potential for water and sediment to drop out, and for erosion. This assessment is based on evaluations that include periodic testing to ensure that the S&W content does not exceed tariff quality limits as well as analysis of operating conditions to ensure that corrosive conditions do not develop. Enbridge has stated that a key component of its Internal Corrosion Control Program is the regular analysis of internal pipe corrosion susceptibility, based on the use of several leading and lagging indicators in conjunction with flow models to evaluate the potential internal corrosion threat. When water and sediment drop out are predicted, Enbridge relies on maintenance pigging to prevent potential corrosive materials from persisting in the pipeline for extended periods. Enbridge has stated that it predicts a cleaning frequency of 2-4 times per year on each trap-to-trap section.

#### **6.1.1.2.4. Assessment Practices**

Internal wall loss is readily distinguished from external wall loss using the in-line inspection technologies that were discussed in Section 6.1.1.1.6, and so this form of assessment is equally applicable and reliable for assessing a pipeline from the perspective of an internal corrosion as it is from the perspective of external corrosion. Enbridge has adopted the same analysis procedures as described in Section 6.1.1.1.6, except that the repair criteria for internal metal loss is 50% of wall thickness, rather than 80% of wall thickness for external metal loss, reflecting a greater degree of uncertainty with in-the-ditch measurement of internal metal loss than for external metal loss. The repair criteria for internal corrosion account for the potential growth of internal corrosion.



As has been previously stated, piping inside stations is not typically accessible by in-line inspection due to the complex configuration of station piping. Instead, industry best practice for the assessment of station piping for internal corrosion includes the identification of potential water and solids hold-up points (typically at piping dead-ends and low points), and follow-up excavation and in-the-ditch assessment using non-destructive examination (NDE) methods at these locations. Good industry practice would involve an ongoing surveillance program that selectively targets potential hold-up points to confirm that internal corrosion is not occurring. In its Facilities Engineering Assessment, Enbridge reports that since 2006, several internal inspections have been completed on piping at the Facilities using this approach.

### **6.1.1.3 Erosion**

Internal erosion occurs when solids that are entrained within a product stream impinge on the inside surface of a pipeline and cause mechanical wear of the line pipe surface. Erosion susceptibility is a function of several factors, most specifically: flow velocity, solid particle concentration, particle size distribution, shape, mass and hardness, as well as the presence of bends (especially elbows and other fittings). Pipeline erosion most commonly occurs in the oil production industry where production (field) pipelines contain fluids with high levels of sand and minerals. It is not common in crude oil transmission pipelines, where solid particle concentration in the product stream is controlled by tariff specifications. With respect to the proposed transportation of dilbit, as stated in Reference 7, “the generally low levels of solids (less than 0.05 percent) do not suggest that shipments of diluted bitumen increase the already low potential for erosion in crude oil transmission pipelines”.

In its Facilities Engineering Assessment, Enbridge has stated that its analysis has shown that the proposed maximum flow velocity is below its internal design limit for erosion.

### **6.1.2 Cracking**

Line 9B is susceptible to cracking, and three forms of cracking have been observed to date:

1. Stress Corrosion Cracking (SCC);
2. Cracking resulting from mechanical damage; and,
3. Fatigue cracking

SCC is a form of environmental cracking that can occur in association with some older coating types, including the polyethylene tape coating system that was used on Line 9B. Other factors controlling the incidence and severity of SCC include stress level, and susceptible environment. Enbridge has noted the presence of numerous SCC cracks along Line 9B, although there have been no leaks associated with these cracks to date. Nevertheless, SCC is considered a time-dependent threat, and once initiated, a subset of the population of these cracks may continue



to be active, and may continue to grow to failure unless they are pre-emptively detected and repaired.

The only failure attributed to cracking in Line 9B occurred in 1991, and was associated with a piece of 1" diameter densitometer piping that had been lifted by a culvert due to frost heave. While this form of mechanical damage is not characteristic of systemic cracking, it should be noted that seven other leaks, occurring between the years of 1978 and 1999 were characterized as having been attributed to dents. In six of these incidents, the incident record indicated that cracks were associated with a dent. This type of crack-in-dent damage is mechanically-induced, and is often associated with locations where the pipe may be resting on a rock. In some circumstances, fatigue loading due to pressure cycling or external forces, or alternately, environmental conditions can cause a crack to initiate and grow to failure.

Enbridge conducted a review of the operating characteristics that are associated with their proposed pipeline conversion, including the proposed pressures, flow, and products, and in their Pipeline Integrity Engineering Assessment, they documented the results of that review, concluding that the proposed conversion will not increase the failure potential associated with the threat of cracking. The independent review that was conducted as part of this analysis resulted in the same conclusion; the changes in operation that are associated with the proposed conversion will not result in an increase in the threat of failure due to cracking. The more significant issue is the magnitude of that threat level, regardless of the proposed change, and whether that threat level is being adequately managed.

There are a limited number of strategies available to manage the threat of failure due to cracking. The two most effective strategies are hydrostatic testing and in-line inspection. In order to continually detect a population of cracks that may be growing in service, both of these strategies need to be employed repetitively, with intervals between implementations that are carefully designed, based on flaw sizes detected and crack growth rates.

Enbridge has conducted one hydrostatic test on Line 9B since it was originally commissioned in 1976. This test was conducted in 1997 as part of the National Energy Board approved OH-2-97 line reversal project. No leaks or ruptures were reported.

One in-line inspection survey was completed on the ML-CD segment in 2003 using a GE-PII USCD crack detection tool.<sup>8</sup> This inspection was the basis of the analysis conducted in

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<sup>8</sup> Reflects revised information as per NEB IR# 1.22.



Enbridge's Pipeline Integrity Engineering Assessment, however this data set is likely too dated provide clear insight as to the current nature and significance of the cracking threat, especially as crack detection technology has improved significantly since that time. Additional crack tool inspections were conducted on the ML-CD segment in 2012 using USCD+ as well as Axial Flaw Detection (AFD) technology; the latter of which, while not characterized as a 'crack detection technology' per se, can detect some cracks under some circumstances. Therefore, it is believed that the 2012 crack detection dataset and the analysis of that dataset will make the 2003 dataset obsolete. Therefore, rather than focusing on the findings of the 2003 crack inspection, the analysis approach was scrutinized to assess the adequacy with which Enbridge's crack inspection program and their crack data analysis procedures address the cracking threat on Line 9B.

While Magnetic Flux Leakage (MFL) or Ultrasonic Metal Loss technology has matured to the point where the detection and sizing of volumetric wall loss (e.g. corrosion) defects using in-line inspection tools can be performed with a significant degree of reliability, crack detection tool technology hasn't yet reached a level of maturity that is considered by the pipeline industry to be commensurate with metal loss detection technology. While ILI crack detection is an area of technology that has advanced rapidly in recent years, practices vary across the industry as a function of quality specifications and procedures, which are often driven by pipeline operators themselves.

#### **6.1.2.1 Technology Limitations of Assessment Techniques**

Each of the main assessment technologies associated with crack detection have limitations that are related to physical limitations that are inherent with the physical constraints that are associated with each technology. The following outline of the limitations of hydrostatic testing and in-line inspection is intended to illustrate that each assessment method has its own limitations. With respect to the potential role of hydrostatic testing in an overall integrity management plan, as the following discussion will illustrate, given its limitations, hydrostatic testing cannot be considered 'better' than in-line assessment, however it may provide a basis for helping to validate the reliability of an in-line assessment program if that reliability cannot be demonstrated by analysis alone.



### 6.1.2.1.1. *Hydrostatic Testing*

Hydrostatic testing procedures are specified in CSA Z662-11 Clause 8.<sup>9</sup> This Clause specifies that hydrostatic tests should be conducted at pressures that range from 1.25 x the Maximum Operating Pressure (MOP) of the pipeline to a maximum of a pressure that corresponds to 110% of the specified minimum yield strength (SMYS) of the pipe material. Therefore, pipelines that operate at pressures commensurate with 72% SMYS would be hydrostatically tested at pressures that range from 90% SMYS at a minimum to 110% SMYS at a maximum. Hydrostatic testing only detects those defects that are large enough to be considered critical at the elevated pressure associated with hydrostatic testing, and provides no information about the nature or number of smaller defects that can withstand hydrostatic pressures.

For time-dependent flaw growth mechanisms, such as SCC or fatigue cracking, hydrostatic testing must be conducted at regular intervals, established on the basis of an analysis that considers parameters such as projected flaw size distributions, flaw growth rates, material properties, operating pressures, and pipe design. Enbridge undertakes to establish flaw growth rates for both SCC and fatigue using analytical techniques described in the Pipeline Integrity Engineering Assessment. These growth rate models were reviewed, and while the analysis approaches that were described were found to be representative of industry leading practice, the results of the flaw growth analysis were not included in the Pipeline Integrity Engineering Assessment. Nevertheless, average SCC crack growth rates reported in the literature range from 0.1 to 0.3 mm/yr, whereas fatigue crack growth rates can vary both below and above that range as a function of flaw size and stress range.<sup>10, 11, 12</sup>

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<sup>9</sup> It should be noted that the intent of this Clause is to specify hydrostatic testing requirements for the qualification of pipelines, rather than to specify requirements for the use of hydrostatic testing as an assessment method for pipelines that are already in operation. There is no corresponding Clause in the CSA Z662-11 code that prescribes specific test pressures and durations for the purposes of performing assessments of operating pipelines that are already qualified. Nevertheless, the test pressure guidelines in Clause 8 are still relevant to assessment practices. The test durations of a 4-hour strength test followed by a 4-hour leak test that are specified in Clause 8 may or may not be followed in a pressure test being that is being used to perform an assessment, and it is not uncommon for shorter-duration “spike tests” of a few minutes to 1 hour to be used, followed by a longer leak test of several hours duration.

<sup>10</sup> Report to the National Energy Board of Canada “CEPA Report on Circumferential Stress Corrosion Cracking”, December, 1997

<sup>11</sup> Department of Transportation Research and Special Programs Administration Office of Pipeline Safety “Stress Corrosion Cracking Study”, Report No. DTRS56-02-D-70036

<sup>12</sup> Elboujdaini, M., and Shehata, M.T., “Stress Corrosion Cracking: A Canadian Perspective for Oil and Gas Pipeline”, CANMET Materials Technology Laboratory, Natural Resources Canada

Typical hydrostatic re-test intervals employed by industry to address time-dependent cracking range from 4 years to 10 years. However, as illustrated in Figure 2 and Figure 3, even at short re-test intervals, a regular hydrostatic re-testing program cannot guarantee failure-free service. These two figures show the ‘critical flaw sizes’ (i.e., the sizes of flaws that would fail) at both an operating pressure level commensurate with 72% SMYS, and at a hydrostatic test pressure level commensurate with 90% SMYS.<sup>13</sup> Figure 2 shows the critical flaw size curves for 6.4 mm wall thickness pipe, which represents light-wall pipe segments of Line 9B, while Figure 3 shows the critical flaw size curves for 12.7 mm pipe, which represents one of the heavy-wall pipe designs of Line 9B.

Some key points should be noted from these two Figures:

- For a given pressure level, as flaw length decreases, the flaw depth that is required to precipitate a failure at that pressure level increases;
- For longer flaws, the difference in depths between those flaws that would fail at 72% SMYS and those that would fail at 90% SMYS is greater than for short flaws (e.g., in Figure 2, the difference in critical depths at a flaw length of 30 cm is 0.91 mm, whereas the difference in critical depths at a flaw length of 2 cm is 0.22 mm);
- This differential between critical flaw depths of shorter flaws is smaller at greater wall thicknesses (e.g. as shown in Figure 2, for a pipe with a 6.4 mm wall thickness, the difference in critical depths between 72% SMYS and 90% SMYS for a 2 cm long flaw is 0.22 mm, whereas as shown in Figure 3, for a pipe with a wall thickness of 12.7 mm, this difference is only 0.14 mm. This behaviour occurs because the onset of failure for short flaws is governed primarily by crack growth through the remaining ligament. This is particularly the case for thicker wall thicknesses where the failure of short flaws is relatively insensitive to changes in operating stress; and,
- Above a threshold flaw length, cracks may fail by rupture (denoted as ‘break’ in Figure 2 and Figure 3), rather than by leak. The primary distinguishing feature of ruptures is rapid crack extension in both the through-thickness and length directions once a crack reaches a critical size. With leaks, there is little or no extension in the axial direction, and the through-wall penetration of the pipe membrane is typically confined to the length of the crack.

As can be seen from an inspection of Figure 2 and Figure 3, given a flaw growth rate that is typical of SCC growth, even a hydrostatic re-test frequency that is as short as once per year might not be sufficient to prevent in-service failures, since the difference between critical flaw

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<sup>13</sup> Curves generated using Modified NG-18 failure model



depths at hydrostatic test pressures and at operating pressures can be as small as 0.14 mm at short flaw lengths (recall that average crack growth rates for actively growing SCC range from 0.1 to 0.3 mm/yr).

The above explains, in part, why hydrostatic testing is more favoured as an assessment strategy in natural gas transmission pipelines than it is for liquids pipelines. The consequences associated with natural gas transmission pipeline failures are greater for ruptures, which can generate large releases of natural gas and accompanying large public safety hazard zones in the event of the ignition of the gas cloud. For natural gas transmission pipeline leaks, however, the potential thermal hazard zone is typically so small as to be considered negligible. As illustrated in Figure 2 and Figure 3, hydrostatic re-testing is an effective strategy for preventing ruptures. Therefore, even though hydrostatic re-testing might not be as effective a strategy for the prevention of all leaks, from a risk perspective, (which considers both failure likelihood as well as consequences of failure) hydrostatic re-testing can be an effective risk-mitigation strategy for natural gas transmission pipelines.

This large difference between the consequences associated with ruptures and leaks is not as pronounced with liquids pipelines, since leaks in liquids pipelines may result in significant environmental damage, especially if they are not detected promptly. Therefore, hydrostatic re-testing isn't as effective a risk mitigation strategy for liquids pipelines as it is for natural gas pipelines.



Figure 2

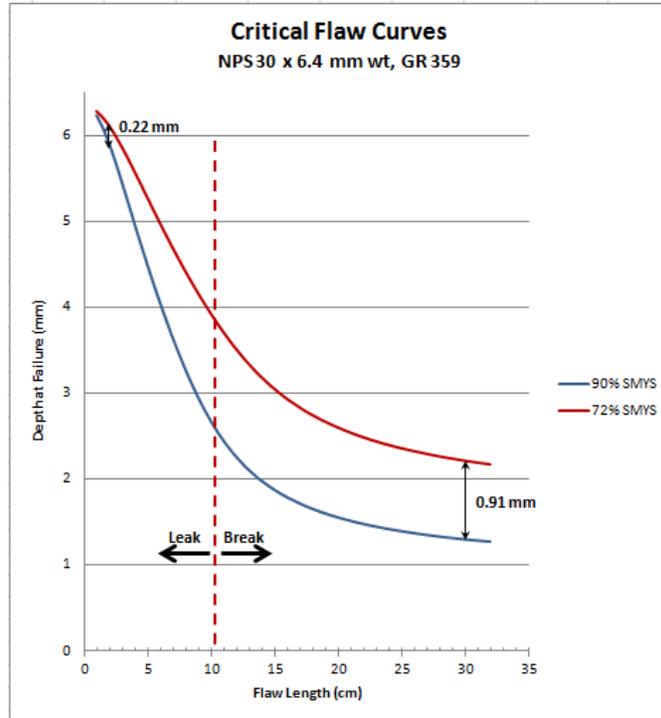
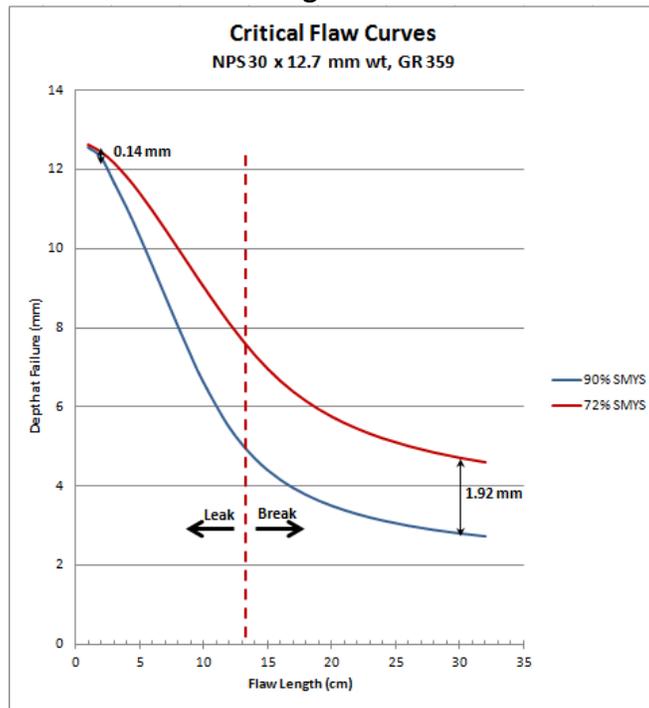


Figure 3





While there is no wide-spread industry consensus, one additional limitation of hydrostatic re-testing is the potential for repeated hydrostatic tests to impart large fatigue cycles on sub-critical flaws, thereby accelerating the growth of a population of sub-critical cracks. This position is sometimes countered by an argument that suggests that hydrostatic testing can impart a compressive residual stress zone at the tip of remaining flaws, thereby retarding future crack growth.

#### **6.1.2.1.2. *In-Line Inspection***

Crack detection using in-line inspection technologies has the advantage of being able to detect cracks that are much smaller than would be detected using hydrostatic re-testing, thereby providing much more information regarding crack incidence rates and crack size distributions. Nevertheless, crack detection using in-line inspection has its own limitations.

Although no specifications were presented in the Pipeline Integrity Engineering Assessment for the crack detection capabilities of the 2012 GE USCD inspection, the capabilities of this tool when it was run in 2003 were reported as  $\geq 1$  mm in flaw depth for a flaw length of 60 mm.<sup>14</sup> Flaws that either don't meet the minimum depth threshold, or that don't have a minimum length of 60 mm are therefore outside the inspection tool's performance specifications. Flaws whose sizes correspond to the minimum detection threshold are well within the safe operating limits of Line 9B. For illustration purposes, reference to Figure 2 illustrates that even for the 'light-wall' (6.4 mm w.t.) portion of the pipeline, a flaw that is 60 mm long would need to be approximately 4 mm deep in order to fail a hydrostatic test at 90% SMYS, and would need to be approximately 5 mm deep in order to fail at operating pressures corresponding to 72% SMYS. Therefore, if the inspection tool could be 100% reliable in identifying all flaws within its published detection threshold, this would result in a large margin of safety. Nevertheless, subsequent to the 2003 inspection, 206 flaws were discovered that fell within this published detection threshold, but which were not identified by the tool. The lowest predicted failure pressure of these 'false negatives' was 125% of the NEB-approved maximum operating pressure. This is equal to Enbridge's repair threshold (note that CSA Z662-11 does not prescribe a repair threshold as such for cracks; only that an engineering assessment be conducted to establish acceptability). Based on Enbridge's analysis, the remaining life of this crack was determined to be 36 years.

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<sup>14</sup>During the 2012 in-line inspection program, the ultrasonic CD+ tool was used to inspect Line 9B. This is a more recent generation of USCD crack detection tool.



Probability of detection (POD) is defined as the number of detectable features identified by the ILI tool, divided by the total number of detectable features, including false negatives. Overall, the POD for the 2003 USCD inspection of the ML-CD segment was reported as 84%. This is likely a non-conservative estimate, since false negative features are discovered by chance. On the surface, this POD value is undesirably low, although discussions with Enbridge staff suggested that the problem of false negatives is primarily associated with features that are close to the published detection threshold of the tool. Regardless, it is not possible, based on a deterministic analysis such as was contained within Enbridge's Pipeline Integrity Engineering Assessment to ascertain the impact that false negatives will have on pipeline reliability.

Beyond the issues related to flaw detection as they relate to pipeline reliability, there are physical tool technology limitations associated with some forms of cracking. Specifically, cracks that may be associated with mechanical damage, such as dents, present geometric challenges that may render them difficult to detect using current in-line inspection technology. As indicated by Enbridge in its IR Response to OPLA #1.51, there is no tool within the industry that can reliably detect and size crack features located within pipe deformations. In that IR Response, however, Enbridge stated that it is engaged with the industry through several joint initiatives and sponsored projects aimed at closing this gap. The IR Response went on to state that Enbridge has established a threat integration process that aligns data (including those gathered from geometric ILI tool runs) from several ILI data sets to determine coincident features that may require mitigation. A detailed description of this process, and of the reliability with which cracks in dents might be detected wasn't given in either the IR Response or the Pipeline Integrity Engineering Assessment.

### **6.1.3 External Interference**

External interference failures are those that are related to accidental contacts of the pipeline with heavy equipment, such as excavators, by 1st, 2nd, or 3rd parties (i.e., the pipeline operator's own equipment, that of its contractors, or by others). This sort of heavy equipment contact can result in mechanical damage such as dents, gouges-in-dents, or penetrations, which may or may not result in leaks or ruptures – either immediate, or delayed. This is a threat that virtually all pipelines are susceptible, and it is one of the leading causes of failure in North American transmission pipelines. As pointed out by Enbridge in its Pipeline Integrity Engineering Assessment, pipelines with a high diameter-to-thickness (D/t) ratio (typically, > 100) are more susceptible to failure by mechanical damage than pipelines with lower D/t ratios. With a D/t ratio of 119, the 6.4 mm wall thickness portions of Line 9B have this characteristic susceptibility. Nevertheless, Enbridge's proposed pipeline conversion will not in any way impact the threat of failure due to external interference.



Enbridge's response to NEB IR #1.27 indicates that there have been two leaks and one rupture associated with external interference, as follows:

- A 1978 rupture of the main line at a location of previous damage;
- A 1993 leak associated with a 2" diameter fitting, which was inadvertently struck with a backhoe; and,
- A 2005 leak attributed to a contractor striking a grease port fitting on a mainline valve

This failure threat has been the focus of a great deal of attention by the pipeline industry, resulting in the development and adoption of damage prevention programs by pipeline operators. Enbridge's program, which it calls its Mechanical Damage Prevention Program (MDPP) is designed to address the threat of damage in the form of dents, gouges, etc. from a variety of sources, including strikes from excavating equipment and pipe settlement onto rocks. The two main components of this program are damage prevention, and damage detection – the latter intended to pre-emptively detect damage before it manifests itself as a leak or rupture.

#### **6.1.3.1 Damage Prevention Program**

In its Pipeline Integrity Engineering Assessment, Enbridge summarizes the components of its damage prevention program as including the following elements:

- Public Awareness Program ("PAP");
- Right-of-Way signage;
- Participation in local One Call organizations;
- Participation in industry community awareness programs;
- Depth of cover surveys; and
- Right-of-Way patrols

Enbridge indicated in its Pipeline Integrity Engineering Assessment that Line 9B is patrolled by helicopter every two weeks. Part of the purpose of these patrols is to identify any ground disturbance, and to pre-emptively detect any construction activity along the right-of-way; both of which would precipitate on-site intervention and investigation.

Enbridge indicated in its response to Jessie McCormick IR #1.3 that it walks the right-of-way of Line 9B every 9 to 10 years as part of a depth of cover survey. In response to Toronto IR #1.14 b), it indicated that the most recent depth of cover survey performed in the Québec portion of the pipeline was in 2008 along some segments between Terrebonne Station and Cardinal Station. In response to OPLA IR # 1.81, Enbridge indicated that during a depth of cover survey, depth measurements are taken at 30 m intervals unless ground conditions warrant more frequent measurements, such as near ditches, fence lines, or the edges of roadways. At



locations where the depth cover over the pipeline is found to be less than 0.8 m, the local Enbridge maintenance office is notified for immediate follow-up.<sup>15</sup> Local maintenance representatives verify the depth and take necessary steps to mitigate depth of cover concerns. This may include notifying the landowner immediately of the concern, staking the area found to have insufficient cover to prevent equipment from operating over the pipeline until remediation can be completed, and either adding cover or lowering the pipeline through the area found to have insufficient cover. If it is not possible to achieve the required depth of cover, then alternative mitigative measures may be employed including, for example installing a protective mechanical barrier such as a concrete slab.

While no additional information beyond the above was available that provides detailed information on Enbridge's damage prevention and public awareness practices, the information that was available is representative of industry best-practices. The one outstanding item related to the damage prevention program relates to depth of cover surveys. As indicated above, a more comprehensive understanding of the timing and results of the most recent depth of cover survey – especially in areas that are densely populated and that coincide with light-wall pipe - would provide greater assurance that this threat is being adequately managed. This is further addressed in Section 7.3.

### **6.1.3.2 Damage Detection Program**

ILI tools that are utilized to detect deformation and potential mechanical damage include both ILI geometry tools and metal loss tools. The primary ILI technology used to detect and identify mechanical damage is geometry (caliper), which physically measures variances in the internal diameter of the pipeline to identify geometry features indicative of mechanical damage. In addition to identifying features in the pipeline, modern technologies have the ability to characterize those features in shape (plain, smooth, symmetrical, sharp, multi-apex), circumferential orientation (top side vs. bottom side and proximity to long seam welds), axial position (distance from nearest girth weld) and depth.

In its Pipeline Integrity Engineering Assessment, Enbridge indicated that prior to use, caliper ILI vendors and their accompanying technologies are required to complete a qualification process to ensure that the tool will meet the required performance and reporting standards. All caliper

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<sup>15</sup> Enbridge later corrected this value to be 0.6 m, consistent with minimum cover and clearance requirements for new low vapour pressure pipelines specified in CSA Z662-11



ILI tools utilized by Enbridge have minimum dent detection capabilities of 2% of the pipe outside diameter. These tools also detect dents less than 2% in depth, but sizing of dents less than 1% in depth can be unreliable. Enbridge requires that all dents equal to or greater than 2% of pipe outside diameter to be reported in the ILI report. All geometry features identified by metal loss technologies are reported, and all geometry features, regardless of depth, that are associated with secondary features such as metal loss, gouging or welds are evaluated. These data are integrated with caliper data to determine actual dent depths to assist in determining the need for additional assessment or field investigation.

Enbridge's excavation and field assessment criteria are as follows:<sup>16</sup>

- All dents  $\geq$  6% of diameter;
- Top-side (between 8:00 and 4:00) dents  $\geq$  2% of diameter;
- Dents  $\geq$  2% of diameter in weld regions;
- Dents in association with metal loss or other stress risers; and,
- Dents in close proximity with one another, or identified as having multiple apexes

The above criteria meet the requirements of CSA Z662-11, Clause 10.10.4.2, which details acceptance criteria for dents.

Prior to the 2012 caliper tool inspection of the ML – CD segment, this segment was last inspected for mechanical deformation in 2007 and the results of that inspection are summarized in Enbridge's Pipeline Integrity Engineering Assessment. A total of 12 features were excavated subsequent to that inspection; 11 because they met the above criteria, and one for validation.

#### **6.1.4 Material and Manufacturing Defects**

Failures that are related to material and manufacturing defects include those that are attributed to conditions such as hard spots or manufacturing seam defects. Through the history of pipe manufacturing and operation, there has been a strong correlation between the incidence of failures attributed to this threat and to the variables of pipe vintage,

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<sup>16</sup> The criteria listed in the Pipeline Integrity Engineering Assessment lists dents  $\geq$  2% of diameter in conjunction with metal loss or other stress risers and dents  $\geq$  2% diameter having multiple apexes, or in close proximity with one another. Follow-up correspondence with Enbridge revealed that these criteria were incorrectly documented in the Pipeline Integrity Engineering Assessment. In fact, there is no minimum dent depth attached to any of the above dent types, and all dent depths are considered to exceed the criteria.



manufacturing process, and manufacturer.<sup>17</sup> As summarized in is Table 1, Line 9B was constructed with double-submerged arc welded (DSAW) pipe manufactured in 1975 by Stelco. Reference 17 indicates no particular susceptibility to manufacturing-related failures experienced in the industry to this combination of vintage / manufacturer / manufacturing process. Enbridge’s experience on Line 9B is consistent with this industry experience, and there have not been any recorded in-service or hydrostatic test failures attributed to this threat.

The potential for failure due to manufacturing and materials defects can never be completely dismissed on any liquids pipeline, since fatigue loading associated with pressure cycles can cause previously undetected flaws – particularly axially-oriented longitudinal seam weld flaws – to grow in service to a critical size. Nevertheless, a comprehensive crack management plan as discussed in Section 6.1.2 will address this threat in an adequate fashion. Enbridge’s proposed pipeline conversion will not adversely impact the threat of failure due to materials or manufacturing defects.

### **6.1.5 Construction Damage**

Failures that are related to construction damage include those that are attributed to construction-related conditions such as welding defects, rock damage (dents), and wrinkle bends.

Wrinkle bends are related to vintage construction practices, which predate the 1975 installation date of Line 9B, and are not considered to be a realistic threat for that pipeline. This fact is readily verified by in-line inspection.

As indicated in Enbridge’s Pipeline Integrity Engineering Assessment, circumferential welds were completed and inspected at the time of construction to the existing CSA Z183-73 code requirements. While this would entail the same shielded metal arc welding process that is still in current use, it is unclear as to the level of radiographic inspection that was employed during construction. Regardless, welding defects are considered to be stable, and tend not to grow to failure unless acted upon by external forces such as settlement or land movement, and are not typically affected by operational pressures and flow conditions. This will be further addressed in Section 6.1.6. There is no foreseeable means by which the potential for failures related to welding defects to be affected by the proposed conversion being proposed by Enbridge.

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<sup>17</sup> Clark, E.B. and Leis, E.B., “Integrity Characteristics of Vintage Pipelines”, Interstate Natural Gas Association of America Report F-2002-50435, October, 2004.



While dents due to rock damage are characterized as a construction defect, the mechanism for failure is typified by in-service fatigue loading, resulting in crack formation and growth. This threat mechanism has already been addressed in Section 6.1.2. As was concluded in that section, the changes in operation that are associated with the proposed conversion will not result in an increase in the threat of failure due to this mechanism.

### **6.1.6 Geotechnical / Hydrological Hazards**

Various forms of geotechnical hazards, including landslides, frost heave, and ground settlement can result in pipeline failures; similarly, any hydrological hazards such bank erosion or floods that can uncover a pipeline and expose it to flowing water or debris can result in pipeline failures. No past failures related to geotechnical or hydrological hazards have occurred at any location along Line 9B, and while the likelihood of incurring a failure resulting from these threats will not be impacted by the pipeline conversion being proposed by Enbridge, a review of Enbridge's Slope, Pipeline Movement, and River Crossing Management practices was undertaken to ensure that this threat is adequately being addressed by their current program.

#### **6.1.6.1 Slope Management Program**

Enbridge summarized its Slope Management Program in its Pipeline Integrity Engineering Assessment. That summary highlights the following essential elements of its program, presented in order of escalating response:

- Bi-weekly inspections to identify evidence of slope instability;
- Detailed geotechnical assessment of areas of suspected slope instability;
- Evaluation of impact to pipeline;
- Additional monitoring such as supplemental right-of-way patrols, scheduled geotechnical inspections, or slope instrumentation;
- Remediation, such as slope improvements, pipeline stress relief, or line locating.

In Enbridge's Pipeline Integrity Engineering Assessment a description was provided of locations where an escalating response has been initiated to address increased slope stability threat levels; none of which are in Québec. Nevertheless, very little information was provided in any of the documents available for review that detailed specific identified geohazards, and the monitoring and management practices being implemented to prevent future failures associated with these threats. In the absence of this type of detailed information, it is difficult to assess whether or not Enbridge's slope management program is representative of industry leading practices.



### **6.1.6.2 Pipeline Movement Management Program**

In its Pipeline Integrity Engineering Assessment, Enbridge indicated that locations on the right-of-way that are susceptible to ground settlement, frost heave or unsupported spans are managed through a combination of in-line inspection and right-of-way patrols. Caliper inspections are used to identify wrinkles or buckles that could be the result of pipeline movement, and inertial mapping unit (IMU) in-line inspections are used to monitor for pipeline movement over time. Such movement, if detected and measured, can provide data that can be used to perform a strain analysis to establish fitness-for-service. While such strategies are representative of industry best-practices, they should be supported by a rationale for establishing reassessment interval. No such rationale was available for review.

As of the time of writing of the Pipeline Integrity Engineering Assessment, the most recent caliper survey had been completed in the ML – CD segment in 2007<sup>18</sup>, and the most recent IMU inspection had been completed in 2003. Based on an analysis of the results of these data, Enbridge reported that there were no buckles or wrinkles on Line 9B identified in the caliper survey, nor were there any areas of strain identified in the IMU survey that would require follow-up strain analysis.

### **6.1.6.3 Water Crossing Management Program**

In its Pipeline Integrity Engineering Assessment, Enbridge summarized its Water Crossing Management Program, and highlights the following essential elements of the program, presented in order of escalating response:

- Monitoring of river crossings through a combination of right-of-way patrols, depth of cover surveys, and engineering site visits as required;
  - Right-of-way inspections identify threats such as high water levels, river scour, debris, pipeline exposure, or other phenomenon that may affect the crossing integrity.
  - Findings are communicated to Enbridge engineers for assessment of possible mitigation requirements.
- Depth of cover surveys are conducted every ten years at minor crossings that exhibit lesser exposure risks, and every five years at major crossings.

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<sup>18</sup> A subsequent caliper survey was completed in 2012, but the results of this survey were not discussed in the Pipeline Integrity Engineering Assessment.



- Identification of low cover near a river crossing results in assessment of remediation requirements
- The assessment includes evaluation of any ILI anomalies, unsupported spans, potential loading, river conditions, crossing location, and consideration of landowner consultations.
- Examples of remediation options include are pipeline armoring, line lowering, river re-routing, or line re-routing.

While the Pipeline Integrity Engineering Assessment identifies discrete locations which have required remedial actions, none of these locations are within Québec.

The above constitutes a high-level description of a water crossing management plan that is consistent with industry best-practices, however a more comprehensive and detailed plan would provide greater assurance that the potential for failure at water crossings is being adequately addressed.

#### **6.1.7 Equipment Failure**

Equipment failure includes failure of ancillary equipment, including valves, gaskets, seals and packing. On a transmission pipeline system, this ancillary equipment typically exists within the fenced confines of station facilities, which are often manned, and which typically are designed with physical systems to promote the containment of a leak on site. Industry incident data suggests that release volumes associated with equipment leaks are typically small, being typified by leaking connections, threads, gaskets, etc.

Equipment failure is not a threat that could foreseeably be impacted by the pipeline conversion of Line 9B that is being proposed by Enbridge. While Table 3-2 of the Pipeline Integrity Engineering Assessment and the response to NEB IR #1.27 provide information related to mainline leaks, no information is available on leak rates within station facilities.

#### **6.1.8 Other Causes**

Within Clause H.2.6 of CSA Z662-11, the category of 'other causes' includes threats such as control system malfunctions and other forms of incorrect operation, as well as various other unclassified threats. Control system malfunctions can potentially lead to failures if they fail to perform requested actions as designed or if they perform an action in error, while improper operation can potentially cause failures if incorrect decisions are made due to lack of information or training.

No failures attributed to improper operations have been reported on Line 9B, and this is not a threat that can be expected to be influenced by the conversion of that pipeline that is being proposed by Enbridge.

While the cause of failure associated with the pipeline rupture near Marshall, Michigan in July 2010 (the Marshall incident) was not attributed to incorrect operations, Enbridge undertook a variety of improvements to its pipeline control and control center operations that were initiated both prior to and as a result of this incident. In August and September 2012, the National Energy Board (NEB) inspected Enbridge's Control Room operations in order to assess Enbridge's compliance with the relevant requirements of the Onshore Pipeline Regulations, 1999 (OPR-99).<sup>19</sup> The NEB's inspection and assessment included a review of Enbridge's:

- Pipeline Control and Leak Detection System;
- Pipeline Integrity Management Program;
- Emergency Procedures Program and Public Awareness;
- Management system processes, as required under the OPR-99 and CSA-Z662, to provide for the protection of people, property and the environment; and
- Safety Culture

During this inspection, the NEB found no areas of non-compliances with its regulations that would pose an immediate hazard to public safety or the environment, and the following conclusions were made:

- Since the Marshall incident, Enbridge initiated a broad range of actions to improve the operation of its control room. Some of these have come as a direct result of Enbridge's and the NTSB's investigations into the Marshall incident, while the initiation of other improvements preceded the rupture;
- Enbridge is in the midst of implementing all of its corrective actions, with full implementation of most changes expected in 2013<sup>20</sup>;

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<sup>19</sup> Compliance Verification Under the National Energy Board Act In the Matter of Enbridge Pipelines Inc. Edmonton Control Room Inspection and Assessment, NEB Report OF-Surv-Gen07, May, 2013

<sup>20</sup> A letter from Al Monaco, President & CEO of Enbridge Pipelines to Deborah Hersman, Chairman of the National Transportation Safety Board (NTSB), dated January 15, 2014 indicated that 45 of the 47 commitments made to the NTSB in October of 2012 have been completed (some of the 45 have ongoing reviews and implementations). The status of the remaining two commitments is: i) Enbridge is in the process of conducting a reliability engineering analysis of the effectiveness of hydrotesting in conjunction with ILI utilizing results from recently hydrotested Enbridge pipelines. This work has a target completion of the end of the first quarter of 2014; ii) Leak Detection Equipment Design Standard has been completed, however the addition of leak detection instrumentation is ongoing and has a target completion of the end of the 2nd quarter of 2014.



- Enbridge' s leadership has undertaken efforts to improve its safety culture starting with a commitment from the top of the organization, which is an important part of safety culture advancement; and,
- Consistent with the NEB's expectations for an effective management system, Enbridge has begun implementing an integrated management system.



## 7. Summary and Recommendations

In this Section, the principal findings that have been presented in the previous Section are summarized, and for each threat, the following are provided:

- Summary of threat level, in consideration of past failure incidence, exacerbating factors, and other details;
- Summary of the effectiveness of threat mitigation measures, including an opinion as to whether those practices are representative of industry best-practices;
- A determination of whether the susceptibility to failure from the threat will be adversely impacted by the changes associated with Enbridge's proposed conversion of Line 9B; and,
- Any recommendations for enhancing pipeline integrity

In cases where recommendations are made, attempts have been made to make those recommendations as explicit as possible. Where recommendations address the need for further engineering analysis, however, it should be borne in mind that the outcome of an engineering analysis cannot be prescribed in advance of the completion of that analysis. An example of this is the use of engineering analysis to establish reassessment intervals or the scheduling of inspections. There are no standards that prescribe such assessment intervals or inspection schedules under Canadian regulation. As outlined in Clause N.11 – *Integrity Management Program Planning* of CSA Z662-11, integrity management program planning must be done in consideration of several factors, such as:

- Potential growth of any damage or imperfections;
- Options selected to control identified hazards;
- Options selected to reduce estimated risk level;
- Inspections, testing, patrols, and monitoring;
- Failure and damage incident history, etc.

Recommendations made within this Section that relate to the establishment of integrity management program development and planning through the use of engineering analysis are consistent with the above, and rather than prescribing assessment intervals or inspection schedules, they endeavour to outline a scope, objectives and deliverables of the engineering analysis.

A comparison between the recommendations made in this report and the NEB's conditions that were attached to the approval of Enbridge's Line 9B application is provided as Attachment B.



## **7.1. Metal Loss**

### **7.1.1 External Corrosion**

External corrosion must be considered a potential threat for all pipelines, however the implementation of effective mitigation measures and inspection programs can manage this threat to failure likelihood levels that are essentially negligible. Despite the 38-year-old age and the fact that an older single-layer polyethylene coating system was used on Line 9B, a review of in-line-inspection data suggests that this coating is in good condition – at least as of the 2007 inspection date. Enbridge employs significant use of wall loss in-line inspection technology, having performed a total of 10 wall loss in-line inspections of the ML-CD segment since 1977. In-line inspection technology for wall loss is considered to be very reliable, and Enbridge’s processes and practices for the analysis of wall loss in-line inspection data are considered to be representative of industry best-practices.

In consideration of the information available, the following conclusions and recommendations are made:

- Based on the information available, the threat of failure due to external corrosion on Line 9B is considered to be low, relative to industry performance metrics;
- The change in operating conditions associated with Enbridge’s proposed conversion will not adversely impact this threat;
- This threat is being well managed by Enbridge;
- Enbridge’s external corrosion mitigation practices are representative of industry best-practice; and,
- There are no recommendations for enhancing Enbridge’s external corrosion mitigation practices

### **7.1.2 Internal Corrosion**

Internal corrosion must be considered a potential threat for all pipelines in which there is some opportunity for free water to be transported within the product stream, however as with external corrosion, the implementation of effective mitigation measures and inspection programs can manage the threat of failure due to internal corrosion to levels that are essentially negligible. A review of in-line-inspection data shows no evidence of past internal corrosion on Line 9B – at least as of the 2007 inspection date. The same observations about Enbridge’s use of in-line inspection and the effectiveness of their practices related to the analysis of in-line inspection data that were provided in the discussion on External corrosion apply equally well to internal corrosion.



### 7.1.2.1 Impacts of Product Stream Composition and Flow Rates

In recognition of the particular focus given within the Mandate on the topic of *impacts of product stream composition and flow rates*, a summary of the findings on this topic is provided in a separate section. As noted in Section 2, the first item listed in the Mandate is:

*Verification that the inclusion of information on changes in the composition and volume of the transported crude oil and the impacts of using drag reducing agents on the pipeline have duly been taken into consideration in the Enbridge Pipeline Integrity Engineering Assessment*

Enbridge's proposed conversion of Line 9B will cause changes to two parameters listed in the above item listed in the mandate; the first being *changes in the composition* (including the addition of drag reducing agents), and the second being *changes in the volume of transported crude*.

With respect to the proposed changes in composition, the analysis concluded the following:

- The reduction in maximum sediment and water (S&W) - from 1.0% S&W that is currently permitted in the Line 9B tariff to 0.5% S&W that will be permitted following the conversion of Line 9B - is a net benefit to the prevention of internal corrosion, as it will result in tighter controls on sediment and water entering Line 9B.
- The inclusion of diluted bitumen (dilbit) is not expected to adversely impact the susceptibility of Line 9B to internal corrosion. Dilbit does not have unique or extreme properties that make it more likely than other crude oils to cause internal damage to transmission pipelines from corrosion or erosion. A variety of independent studies have concluded that:
  - Diluted bitumen has density and viscosity ranges that are comparable with those of other crude oils;
  - It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and operating temperature;
  - The amount and size of solid particles in diluted bitumen are within the range of other crude oils and do not create an increased propensity for deposition or erosion;
  - Shipments of diluted bitumen do not contain higher concentrations of water, sediment, dissolved gases, or other agents that cause or exacerbate internal corrosion, including microbiologically influenced corrosion;
  - The organic acids in diluted bitumen are not corrosive to steel at pipeline operating temperatures;



- There is no evidence that operating temperatures and pressures are higher or more likely to fluctuate when pipelines transport diluted bitumen than when they transport other crude oils of similar density and viscosity; and,
- Pipeline operating and maintenance practices are the same for shipments of diluted bitumen as for shipments of other crude oils
- The use of drag-reducing agents is not specific to dilbit transportation. Their use is based on the operational requirements of a particular pipeline segment and throughput required. Drag Reducing Agents consist of long-chain polymers, and they act to dampen turbulence at the interface between the crude oil and the pipe wall to reduce friction and enable increased flow velocity. Drag Reducing Agents themselves are not corrosive, and the authors are unaware of any instances where the use of Drag Reducing Agents were shown to have been instrumental in the promotion of corrosion, or where their use led to the failure of an operating pipeline.
- The proposed conversion of Line 9B will result in an increase in flow rate, as well as a greater consistency of flow. Both of these changes that will accompany the conversion of Line 9B are of net benefit from the perspective of the prevention of internal corrosion, since they will reduce the potential for water and sediment drop-out to occur.

#### **7.1.2.2 Conclusions and Recommendations**

In consideration of the information available, the following conclusions and recommendations are made:

- Based on the information available, the threat of failure due to internal corrosion on Line 9B is considered to be low, relative to industry performance metrics;
- The change in operating conditions associated with Enbridge's proposed conversion will not adversely impact the threat of internal corrosion. This position has been established after having given due consideration of the proposed changes in product stream composition, including the inclusion of dilbit and drag reducing agent;
- The threat of internal corrosion is being well managed by Enbridge;
- Enbridge's internal corrosion mitigation practices are representative of industry best-practice; and,
- There are no recommendations for enhancing Enbridge's internal corrosion mitigation practices



### 7.1.3 Erosion

The product stream and flow characteristics associated with both the existing and proposed pipeline operations are such that this threat is not considered significant. In consideration of the information available, the following conclusions and recommendations are made:

- Enbridge’s metal loss in-line inspection program, discussed in the preceding Sections is an effective means of ensuring that this remains what is considered to be an insignificant threat on Line 9B, based on the information available;
- The change in operating conditions associated with Enbridge’s proposed conversion will not adversely affect this threat; and,
- There are no recommendations for enhancing Enbridge’s mitigation practices, as they pertain to the threat of erosion

## 7.2. Cracking

Line 9B is susceptible to Stress Corrosion Cracking (SCC), cracking resulting from mechanical damage, and operational pressure cycle fatigue cracking. The two most significant factors that contribute to the cracking susceptibility of Line 9B are the use of the single-layer polyethylene tape coating system, and the high D/t ratio of the pipeline, which, when combined with rocky soil conditions, can lead to mechanical damage. Under the operational pressure cycle loading conditions that are characteristic of most liquids pipelines, stress concentrators in the vicinity of mechanical deformation can initiate cracks, which can then grow by fatigue. Stress and localized environmental conditions under disbanded polyethylene coating can cause SCC to initiate and grow. While the operational changes that are associated with Enbridge’s proposed conversion of Line 9B are not expected to adversely impact the threat of failure due to cracking, the more significant issue is the magnitude of that threat level, regardless of the proposed change, and whether that threat level is being adequately managed.

Once cracks are initiated, there is little option but to manage threats associated with cracking by means of assessment programs, such as in-line inspection or hydrostatic testing. Both of these assessment techniques must be repetitively employed, with carefully designed re-assessment intervals. Each assessment technique has its own limitations.

Crack detection in-line inspection technology, while rapidly evolving, hasn’t reached the level of maturity that metal loss in-line inspection has, and so cracks are not typically detected and sized with as large a degree of reliability as metal loss is. This is particularly true for cracks in geometric discontinuities, such as dents. A more complete review of crack detection and analysis using in-line inspection is provided in Attachment A to this report.

Hydrostatic testing provides limited information regarding crack incidence rates or crack size distribution, and while it can be relied upon to pre-emptively remove longer near-critical flaws it isn't as reliable in doing so for shorter flaws to prevent growth to failure between hydrostatic tests. Since the environmental consequences associated with leaks of oil pipelines can be significant (especially if those leaks are small enough that they cannot be readily detected with conventional mass balance system technology), hydrostatic testing can't be considered a highly effective risk mitigation strategy for oil pipelines if relied upon on its own.

Based on an analysis of the 2003 USCD inspection of the ML-CD segment of Line 9B, probability of detection (POD) was determined to be 84%. This does not correspond to a large degree of reliability, particularly since the number is probably non-conservative (false-negatives – one of which had a calculated failure pressure of 125% MOP are discovered primarily by chance). The issue of POD and false negatives was addressed in Enbridge's Pipeline Integrity Engineering Assessment by means of a deterministic analysis. This type of analysis doesn't address the significance of POD and false negatives in terms of structural reliability. For instance, an inability to reliably detect smaller cracks that are close to the inspection tool's detection threshold might not have a large impact on the likelihood of incurring an in-service failure subsequent to inspection. That would not be the case, however, if larger cracks, closer to critical flaw size at operating pressure, could not be reliably detected. A reliability analysis that incorporates an understanding of POD for various flaw sizes and relates that correlation to pipeline reliability would provide a more definitive basis for establishing the likelihood of failure. In that analysis, Enbridge should also address the issue of cracks within deformations, incorporating the capabilities of its threat integration process to enhance POD for that type of damage.

In consideration of the information available, the following conclusions and recommendations are made:

- The threat of failure due to cracking on Line 9B is not currently well established on the ML-CD segment of Line 9B through the deterministic analysis of the 2003 USCD ILI data as presented in Enbridge's Pipeline Integrity Engineering Assessment;
- The change in operating conditions associated with Enbridge's proposed conversion will not adversely impact this threat;
- Enbridge's 2012 USCD and AFD inspections of the ML-CD portion of Line 9B represents an industry state-of-the-art assessment for the types of cracking threats that present themselves on that segment, and the analysis of those data present significant opportunities for advancing the reliability of that segment; and,
- The following recommendations are made for enhancing Enbridge's cracking mitigation practices:



- Enbridge should complete an engineering assessment based on the in-line inspection data acquired in the ML-CD segment in 2012, and the follow-up excavations. The timing of this engineering assessment should match that cited in Condition #9 of the NEB Reasons for Decision (i.e., 90 days prior to applying for Leave to Open).
- The engineering assessment referred to above should incorporate a reliability analysis of the in-line inspection data and the follow-up excavations
- The reliability analysis should be used to augment Enbridge's deterministic analysis, as presented in the Pipeline Integrity Engineering Assessment
- The reliability analysis should be used to incorporate an understanding of POD for various flaw sizes and relate those correlations to pipeline reliability
- The reliability analysis should also address the issue of cracks within deformations, incorporating the capabilities of Enbridge's threat integration process to enhance POD for that type of damage
- The aim of the above analysis should be to demonstrate a satisfactory level of pipeline reliability, based on the use of in-line inspection. If necessary, other assessment methods, including hydrostatic testing, should be considered for the purposes of validating the capability of current in-line-inspection technologies and analysis techniques to impart a satisfactory level of pipeline reliability

### **7.3. External Interference**

External Interference is a threat that virtually all pipelines are susceptible, and it is one of the leading causes of failure in North American transmission pipelines. Pipelines with a high diameter-to-thickness (D/t) ratio (typically, > 100) are more susceptible to failure by mechanical damage than pipelines with lower D/t ratios. With a D/t ratio of 119, the 6.4 mm wall thickness portions of Line 9B have this characteristic susceptibility.

Enbridge employs two separate strategies to prevent failures from external interference; damage prevention, (which focuses on public awareness, signage, one-call programs, depth of cover, and patrolling) and damage detection (which focuses on in-line inspection for the detection of previously damaged pipe. In-line inspection data using a variety of inspection technologies is integrated to assist in identifying complex damage that may involve deformation in conjunction with other defects.

In consideration of the information available, the following conclusions and recommendations are made:

- As with virtually all pipelines, Line 9B is susceptible to the threat of external interference. This would particularly be the case where areas of high land use activity



coincide with light-wall pipe or low depth of cover (although it is not clear from the information provided that these factors do in fact coincide at any location);

- The change in operating conditions associated with Enbridge’s proposed conversion will not adversely impact this threat;
- Based on the information available on Enbridge’s damage prevention and public awareness practices, these practices appear to be representative of industry best-practices; and,
- One recommendation is made with respect to depth of cover. While information regarding depth of cover was available among the materials filed during the National Energy Board Hearing, a more comprehensive understanding of the timing and results of the most recent depth of cover survey - especially in areas that are densely populated and that coincide with light-wall pipe - would provide greater assurance that this threat is being adequately managed. It is therefore recommended that Enbridge provide a report that details the timing and results of the most recent depth of cover survey within Québec, and relates those results to locations that coincide with light-wall (6.4 mm w.t.) pipe in populated areas. The report should provide a remedial plan that provides damage prevention measures for all areas where light-wall pipe coincides with areas where the depth of cover is below 0.6 m within populated areas.<sup>21</sup>

#### **7.4. Materials and Manufacturing Defects**

Failures that are related to material and manufacturing defects include those that are attributed to conditions such as hard spots or manufacturing seam defects. No particular susceptibility to these conditions have been experienced by the industry’s use of the combination of pipe type, vintage and manufacturing process that was used in the construction of Line 9B. Enbridge’s experience on Line 9B has been consistent with this industry experience, and no in-service or hydrostatic test failures have been attributed to this threat.

In consideration of the information available, the following conclusions and recommendations are made:

- The potential for failure due to manufacturing and materials defects can never be completely dismissed on any liquids pipeline, since operational pressure cycle fatigue loading can cause previously undetected flaws – particularly seam flaws – to grow in service to a critical size. Nevertheless, the industry’s operating experience associated

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<sup>21</sup> The CSA Z662-11 standard for cover and clearance for the construction of new low vapour pressure liquids pipelines in general locations is 0.6 m, although there is no minimum depth of cover requirement in that Standard for operating pipelines.



with the type of pipe employed on Line 9B suggests that this line's susceptibility to failure is low, relative to industry benchmarks for a pipeline of this vintage;

- The change in operating conditions associated with Enbridge's proposed conversion will not adversely impact this threat;
- A comprehensive crack management plan as discussed in Section 6.1.2, and especially if implemented with the recommendations given in Section 7.2 will endure that this threat remains well managed; and,
- There are no recommendations for enhancing Enbridge's Materials and Manufacturing Defects mitigation practices

### **7.5. Construction Damage**

Failures that are related to construction damage include those that are attributed to construction-related conditions such as welding defects, rock damage (dents), and wrinkle bends. Based on the era of construction it can be anticipated that Enbridge's construction practices preclude the potential for wrinkle bend failures, and this assumption is readily confirmed from a review of existing in-line inspection data. The shielded metal arc welding process that was used during the construction of Line 9B is still in use in the construction of modern pipelines. Although information pertaining to the level of radiographic inspection that was employed during construction was not available, resident welding defects are considered to be stable, and tend not to grow to failure unless acted upon by external forces (to be further addressed in Section 7.6). Line 9B is susceptible to rock damage, and in-service fatigue loading can result in crack formation and growth. This threat was fully addressed in Section 7.2.

In consideration of the information available, the following conclusions and recommendations are made:

- The threat of failure due to construction damage on Line 9B is dominated by the threat of mechanical damage due to rocks, and the accompanying potential for defects associated with this damage to grow to failure by fatigue. The conclusions and recommendations pertaining to this threat were provided in Section 7.2;
- The change in operating conditions associated with Enbridge's proposed conversion will not adversely impact this threat; and,
- There are no recommendations beyond those contained in Section 7.2 for enhancing Enbridge's Construction Damage mitigation practices



## 7.6. Geotechnical / Hydrological Hazards

The various forms of geotechnical hazard and hydrological hazard, including landslides, frost heave, ground settlement, bank erosion or floods are addressed in Enbridge's Slope, Pipeline Movement, and River Crossing Management programs.

Enbridge's Slope Management Program includes bi-weekly inspections to identify evidence of slope instability, and escalating levels of response including data collection, analysis and remediation where slope instability exists. In Enbridge's Pipeline Integrity Engineering Assessment a description was provided of locations where an escalating response has been initiated to address increased slope stability threat levels. In the documents that were available for review there was very little information detailing specific identified geohazards, and the monitoring and management practices being implemented. However, none of areas of escalating response that were identified those documents were within Québec.

Enbridge's Pipeline Movement Management Program aims to address possible pipe movement through a combination of in-line inspection (using caliper, along with inertial mapping technologies), strain analysis, and right-of-way patrols. At the time that Enbridge's Pipeline Integrity Engineering Assessment was written, the most recent caliper inspection of the ML-CD segment was completed in 2007 and the most recent inertial mapping unit inspection was completed in 2003. No buckles or wrinkles were identified, nor were any areas of strain identified that would require follow-up strain analysis.

Enbridge's Water Crossing Management Program consists of river crossing monitoring through a combination of right-of-way patrols, depth of cover surveys, and engineering site visits, as required. While Enbridge's Pipeline Integrity Engineering Assessment identifies discrete locations which have required remedial actions, none of these locations are within Québec.

While such strategies are representative of industry best-practices, they should be supported by a rationale for establishing reassessment interval. No such rationale was available for review.

In consideration of the information available, the following conclusions and recommendations are made:

- In the absence of detailed specific information regarding the nature of location-specific identified hazards, and the monitoring and the site-specific remediation programs being implemented, it is not possible to comment on the magnitude of this threat as it presents itself along Line 9B, nor is it possible to comment on whether all aspects of Enbridge's practices are representative of industry best-practices;



- The change in operating conditions associated with Enbridge’s proposed conversion will not adversely impact this threat;
- The following recommendations are made with respect to Enbridge’s management of Geotechnical and Hydrological threats:
  - While Enbridge’s use and integration of various forms of in-line inspection technology as part of its Pipeline Movement Program to identify areas of potential pipe movement and strain is considered advanced relative to general industry practice, such strategies should be supported by a rationale for establishing reassessment intervals.
  - The heightened environmental consequences associated with water crossings warrants the inclusion of the following essential elements within Enbridge’s Water Crossing Management Plan:
    - The location and frequency of monitoring activities for specific water crossings;
    - A description of possible hazards at specific water crossings; and,
    - A description of specific remedial actions that would be implemented in response to each hazard
  - The Water Crossing Management Plan should be supported by an evaluation of watercourse-specific information, including hydrographic data, river profiles at crossing locations, sediment characteristics in the immediate vicinity of the crossing, depth of cover, geotechnical assessments of adjacent banks, floodplain maps, scour assessments and flood frequency analysis.

### **7.7. Equipment Failure**

Equipment failure includes failure of ancillary equipment, including valves, gaskets, seals and packing. Industry incident data suggests that release volumes associated with equipment leaks are typically small, being typified by leaking connections, threads, gaskets, etc. On a transmission pipeline system equipment represented by this failure threat typically exists within the fenced confines of station facilities, which are often manned, and which typically are designed with physical systems to promote the containment of a leak on site.

In consideration of the information available, the following conclusions and recommendations are made:

- Insufficient information was provided in any of the documents available for review to evaluate the magnitude of this threat along Line 9B, or to establish whether all Enbridge’s equipment failure management practices are representative of industry best-practices;



- The nature of this threat is such that the change in operating conditions associated with Enbridge’s proposed conversion will not adversely impact this threat; and,
- There are no recommendations for enhancing Enbridge’s equipment failure mitigation practices

## 7.8. Other Causes

Within Clause H.2.6 of CSA Z662-11, the category of ‘other causes’ includes threats such as control system malfunctions and other forms of incorrect operation, as well as various other unclassified threats.

Subsequent to the 2010 Marshall Incident in Michigan, Enbridge undertook a variety of improvement to its pipeline control and control center operations. In August and September 2012, the National Energy Board undertook an inspection and assessment of Enbridge’s:

- Pipeline Control and Leak Detection System;
- Pipeline Integrity Management Program;
- Emergency Procedures Program and Public Awareness;
- Management system processes, as required under the OPR-99 and CSA-Z662, to provide for the protection of people, property and the environment; and
- Safety Culture

During this inspection, the NEB found no issues related to non-compliances with its regulations that would pose an immediate hazard to public safety or the environment, and concluded that the broad range of actions initiated by Enbridge since the Marshall incident resulted in increased performance in the areas of leadership-driven safety culture. It also concluded that Enbridge had begun implementing an integrated management system that is consistent with the NEB’s expectations for an effective management system.

In consideration of the information available, the following conclusions and recommendations are made:

- The primary source for evaluating the magnitude of operations-related threats along Enbridge’s system was findings from the NEB’s independent review completed in 2012. Based on that information source, it appears that Enbridge has undertaken significant operational changes within its organization subsequent to the Marshall incident, such that this threat is being well managed in a fashion that is representative of industry best-practices;
- The nature of this threat is such that the change in operating conditions associated with Enbridge’s proposed conversion will not adversely impact this threat; and,
- There are no recommendations for enhancing Enbridge’s operations practices

## References

### Information Reviewed

The following documents were retrieved from the NEB website related to the Enbridge Line 9A & 9B hearings:

<https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=ll&objId=890819&objAction=browse>

Ref / IR No.	Attachment Exhibit Description	Filing	ID
OH-005-2011	Phase 1 Application Sarnia to North Westover		
A30643	Engineering Mainline Risk Assessment Appendix B 08/2011	B-01 I	A2C0V7
A39519	Response to all of NEB IR-3	B-15B	A2Q4K2
OH-002-2013	Phase 2 Application North Westover to Montréal		
NEB A49446	Attachment 7 – Pipeline Engineering Assessment 11/2012	B1-15	A3D7J4
NEB A49446	Appendix A to Pipeline EA, Contains map with mill, diameter, wall	B1-16	A3D7J5
NEB A49446	Appendix B to Pipeline EA - Compliance & RM-	B1-17	A3D7J6
NEB A49446	Attachment 8 – Facilities Engineering Assessment	B1-18	A3D7J7
NEB 1.21	Attachment 1 Revised Tables 3-4 and 3-5	B8-11	A3G4S7
NEB 1.22	Attachment 1 Revised Tables 3-3 and 4-1	B8-12	A3G4S8
NEB 1.23a	Attachment 1 Figure 4.46 Explained	B8-13	A3G4S9
NEB 1.24a	Attachment 1 Interacting Areas of Corrosion	B8-14	A3G4T0
NEB 1.25a	Attachment 1 Interacting Areas of Corrosion	B8-15	A3G4T1
NEB 1.27a	Att 1 Description of Table 3-2 Known Integrity Features	B8-17	A3G4T3
NEB 1.27b	Att 1 Description of Table 3-2 Unknown Integrity Features	B8-18	A3G4T4
NEB 2.7	Attachment 1 Detailed Project Map	B11-4	A3H3C0
NEB A51669	Attachment 3 – Updated Table 7.6.6 Pipe in Montréal Term	B12-4	A3H3T4
NEB_IR_3.10.c	Attachment 1 Leak detection intervals	B18-7	A3G4T4
NEB 2.7	Attachment 1 Detailed Project Map pp 1-60 - updated	B12-4	A3I6Z3
NEB 2.7	Attachment 1 Detailed Project Map pp 61-120 - updated	B21-5	A3I9H0
NEB 2.7	Attachment 1 Detailed Project Map pp 121-175 - updated	B21-6	A3I9H1
NEB 3.1a	Attachment 1 New Section 2.1 Black lined Version	B42-2	A3K9Q9
NEB 3.1a	Attachment 2 New Section 2.1 Clean Copy	B42-3	A3K9R0
NEB 3.1a	Attachment 3 Updated Documents of Understanding	B42-4	A3K9R1
NEB 3.1a	Attachment 4 ESEIA Addendum	B42-5	A3K9R2
NEB 3.1a	Attachment 5 Noise Impact Assessment Update	B42-6	A3K9R3
NEB 3.1a	Attachment 6 Revised Response to NEB IR 3.1a	B42-7	A3K9R4
NEB 3.6c	Attachment 1 Calculation of Refiner Savings- future volumes	B18-3	A3I6L9
NEB 3.6d	Attachment 1 Employment & Labour Income Effects of Line 9B Reversal – rough PQ vs Ont vs Canada integrity efforts	B18-4	A3I6L9



NEB 3.6e	Attachment 1 Crude Oil Production	B18-5	A3I6Q0
NEB 3.9	Attachment 1 Mainline Transient Analysis Summary Report	B18-6	A3I6Q1
NEB 3.10c	Attachment 1 Estimated Computational Pipeline Monitoring System Sensitivity	B18-7	A3I6Q3
NEB 4.5c	Attachment 1 Estimated Feedstock Cost Saving, MSW Replacing Bonny Light – estimated volume forecasts	B41-3	A3K8F0
NEB 4.7	Att 1 L9B Transient Analysis Summer –September 2013	B45-3	A3L5Z2
NEB 4.9	Attachment 1 Line 9A Emergency Responder/Municipal Agency Visits	B41-4	A3K8F1
AFN & COTTFN 1.9	Attachment 1 Aboriginal Engagement Summary with AFN, June 4 2013	B18-9	A3I6Q4
AFN & COTTFN 1.10	Attachment 1 Aboriginal Engagement Summary with COTTFN, June 17 2013	B18-10	A3I6Q5
MCNFN 1.17	Att 1 Emergency Response Equipment in Eastern Region	B18-12	A3I6Q7
Algonquin to Adirondack 3.vii	Attachment 1 Volume Out Calculations for Streams and Rivers in the Algonquin to Adirondacks Region	B18-15	A3I6R0
Equiterre 1.1.j.1	Att 1 Elevation Profile with Valves and Water Crossings	B18-20	A3I6R5
Equiterre 1.1.j.3	Attachment 1 MOP on centerline	B18-21	A3I6R6
Equiterre 1.3.a	Attachment 1 Location of HCAs Impacted by Line 9	B18-24	A3I6R9
Equiterre 1.3.b	Attachment 1 Location of HCAs subject to Transport Impact	B18-25	A3I6S0
Equiterre 2.1.a	Attachment 2 Pipeline System Configuration	B18-26	A3I6S1
Intervenor IRs A52563	Grand River Indigenous Solidarity 1.b engagement activities with Six Nations May 24, 2013	B18-28	A3I6S3
Intervenor IRs A52563	Attachment 1 Great Lakes and St. Lawrence Cities Initiative IR 2.1.7 ERCB Dilbit not corrosive -	B18-31	A3I6S6
Mississauga IR 1.2.a	Attachment 1: Compliance Verification under NEB EDM Control Room Assessment	B18-48	A3I6U3
OPLA IR 1.32	Attachment 1 CEPA Dilbit Corrosivity by Penspen	B19-5	A3I6V4
OPLA IR 1.33	Att. 1 Dibit Corrosion CANMET NACE rotating cage Paper	B19-6	A3I6V5
OPLA IR 1.33	Att. 2 Dilbit Corrosion CANMET NACE overview paper	B19-7	A3I6V6
OPLA IR 1.78.i	Attachment 1 Max Volume Out Between Valves	B19-10	A3I6V9
OPLA IR 1.79.a	Attachment 1 2012-13 ILI tools used in MI-CD	B19-11	A3I6W0
OPLA IR 1.79.c	Attachment 1 ILI tools-	B19-12	A3I6W1
Toronto 1.5k	Attachment 1 Heavy Crude Properties	B19-32	A3I6Y1
Toronto 1.9.a.d1	Attachment 1 Letter from IPL to NEB May 2, 1988 – additional details on incident report GLa-81 Sleeve on Sleeve Repair	B19-33	A3I6Y2
Toronto 1.9.c.a1	Attachment 1 Excavation sites and Repairs by KP	B19-34	A3I6Y3
Toronto 1.10.e.a1	Attachment 1 Risk Rankings of 305 Metre Sections of Line 9 in GTA - Risk by Segment	B19-35	A3I6Y4
Toronto - 1.27.d.i	Attachment 1 Mock-Emergency Debrief	B19-36	A3I6Y5
Toronto - 1.27.p.i	Attachment 1 Oil Containment Dams	B19-37	A3I6Y6
Ontario Min Energy	Response on Risk	B20-1	A3I6Y8
NEB 2.7	new Risk update June 2013 = +2.2% increase valves	B21-2	A3I6Z1



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NEB 2.7	Revised outflow calc	B21-3	A3I6Z2
NEB 2.7	New alignment sheets	B21-4	A3I6Z3
NEB 2.7	New alignment sheets	B21-5	A3I6H0
NEB 2.7	New alignment sheets	B21-6	A3I6H1
NEB 2.7	New SCADA word change to communications	B21-7	A3I6Z4
NEB 2.7	New unknown features summary sheet	B21-8	A3I6Z5
Toronto 1.23.aR	Attachment 1 Letter from Enbridge to NTSB re Safety Recommendations P-12-11 through -16	B30-3	A3J1I4
NEB 4.7	L9B Transient Analysis Summary - September 2013	B45-3	A3L5Z2



## Attachment A

### Crack Detection and Analysis Using In-Line Inspection

#### Tool Development

In-Line Inspection tools have long used ultrasonic techniques (UT) as the basis of crack detection. These tools have had a long and difficult development path. Enbridge has been a strong supporter over the last two decades and even earlier. The original PII tool was developed by British Gas (which became PII and GE) to find SCC in gas pipelines almost 30 years ago. This pitch-catch ultrasonic technique had the ultrasonic sensors located inside pressurized, liquid filled, special elastomeric wheels, and this complicated path ensured that sound could travel into and back out of the pipe wall for detection. These UT designs were simplified in liquid pipelines using the liquid content as a coupling agent. The physics of sound and travel hasn't changed at all, but the electronics, amplification, prediction and resolution software, and analytical techniques to interpret signals keep improving. The Table below begins to show this development with time.

**Table A.1 – ILI Crack Tool Capabilities Over the Past Decade**

Description of Tool	Tool Location Accuracy	Crack Detection Accuracy		
		Depth (+/- mm)	Depth (% wt)	Axial Length (mm)
GE USCD (2003)	0.1 m	1.0	16	>30
GE USCD (2013)	0.1 m	1.0	16	>25
GE EMATscan CD	0.1 m	2.0	31	>50
Rosen Circumferential Magnetic Flux Leakage (CMFL)	0.1 m	1.0	16	+/- 15

#### Tool Types and Capabilities

The resolution information presented in the first rows of Table A.1 summarizes what can be found in the public record in the response to information requests, and in the 2004 ILI vendor report supplied to Enbridge. Although the capabilities, as reported in the Table look similar, there has been a significant technology change over the last decade.

The final three rows of the Table are a composite of information located on Vendor web sites for GE and Rosen. The ILI tools shown in the last three rows of the Table may have been used in the most recent inspections of line 9B. Note that if API 1163<sup>\*</sup>, which is still not generally used in Canada, was specified in the contract, then each ILI tool must be validated to a reliable statistical performance and show that it can meet the vendor's published specifications. By contrast, the accuracy limits provided in the first row of Table A.1 is essentially what the ILI vendor reported in 2003, and had no statistical framework. If API 1163 is specified, the detection threshold reported in the bottom three rows of the Table would better quantify the statistical envelope for the depth reported 90% of the time.

Crack depths under 15% wall thickness remain difficult to resolve, and this causes problems when determining a continuous length of an individual anomaly if the detection signal reflected from a crack varies in depth both above and below the depth detection threshold. The anomaly, rather than being resolved as a single long crack of varying depth will be interpreted as an irregular string of much shorter non-interconnected cracks. Analytical software is getting better at predicting if the reflections over a distance represent multiple isolated crack indications or the same crack that varies in depth above and below the detection threshold over a much larger length. Both the crack depth and length is required to calculate a failure pressure.

Table A.1 provides two alternate and recently emerged technologies; EMAT (electromagnetic acoustic transducers), and CMFL ILI tools – also called AFD (Axial Flaw Detection) tools. Gas pipelines, since they do not contain a liquid that can be used as an ultrasonic couplant, typically use magnetic methods to bridge the “air gap” and connect the signal in the pipe to the detectors. These techniques allow the signal to cross the small “air gap” between the pipe wall and the sensor. Pipe cleanliness to minimize sensor lift off or air gap is essential to the assurance of reliable readings.

The electromagnetic acoustic transducer (EMAT) is an alternate to the ultrasonic tools more commonly used. These ILI tools have seen rapid development and may soon be very useful in locating and characterizing smaller SCC cracks. They work by using an electronic coil and a steady magnetic field. The coil impresses an AC magnetic field to generate a sound pulse in the pipe wall. The same sensor located on the return path of the sound is used to detect the returning sound signal. The amplitude and shape of the reflected sound plus the amplitude and shape of the non reflected or transmitted signal helps to detect and identify the anomaly. Cracks tend to reflect the whole signal while inclusions and corrosion reflect part so both

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\* API Std 1163 IN-LINE INSPECTION SYSTEMS QUALIFICATION SECOND EDITION, PRODUCT NO. D11632, American Petroleum Institute, APRIL 2013



detectors detect the same sound pulse. To interrogate the entire circumference of the pipe wall as it moves along the pipe, the EMAT ILI tool packs multiple sensors packed in pads around its perimeter.

Circumferential magnetic flux leakage (CMFL) turns the direction of the magnetic field in a conventional axial magnetic flux leakage (MFL) tool from an axial orientation to a circumferential orientation (one provider has the field at 45 degrees). CMFL therefore exploits the knowledge base of all the prior MFL technology. MFL could not be used to find SCC and other longitudinal cracks that develop as a result of the internal pressure (hoop strain) because these cracks are oriented in the axial direction, the same direction as the magnetic field of conventional axial MFL tools. CMFL is directed across the crack such that it can be detected and characterized. In order for detection to occur, the crack opening cannot be too tight; an opening of about 0.2 mm is typically required to cause sufficient flux leakage for detection. As Table A.1 shows, CMFL tools can find cracks below 20% WT, given sufficient crack opening.

### **Dents with Damage**

Dents and dents that contain mechanical damage have been a source of several leaks on Line 9B. The wall thickness to diameter ratio ( $D/t$ ) on line 9B ranges up to 120. Pipe with these higher ratios are less stiff and less resistant to denting. Most simple dent damage is structurally benign up to twice the regulatory limit of 6% of the pipe diameter. Every dent remains a concern for pipelines because each represents multiple levels of threat. Dents can be a simple impression in the pipe's diameter; they could contain corrosion, or mechanical gouging damage and corrosion, or even the triple threat of mechanical gouging with cracks and corrosion.

Physics of the sound path makes it difficult for in-line inspection tools based on ultrasonic technology to identify damage in dents because the reflected signal does not follow the predicted straight line path back to the sensors. The curvature of the dent directs the sound away from the sensors resulting in no signal or the signal arriving at an unexpected sensor well outside of the predicted window of time. This lack of detection will generate a false negative report for ultrasonic tools.

Fortunately MFL, like CMFL can detect slightly open cracks that are oriented normal to the magnetic field of the ILI tool. In addition, recent R&D advances in the detection of the signal inflection or change direction of the magnetic flux at the sensor has been related to the presence of mechanical damage on the surface of the pipe.<sup>†,‡</sup>

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<sup>†</sup> Nestleroth Bruce: "Development of Dual Field MFL Inspection Technology to Detect Mechanical Damage", Pipeline Research Council International Project Number DTPH56-06-T-000016, 2013

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This means that modern MFL and CMFL ILI tools may soon be able to interrogate dents with different levels of damage and begin to classify a dent response according to the range of detected damage severity. Those dents with corrosion that indicate both possible cracking and mechanical damage should receive the primary response priority, followed by those with corrosion and only one of mechanical damage or cracking. Dents containing only corrosion would have the third priority and simple dents represent a fourth priority.

### **Crack Measurement Uncertainty**

To help calibrate the UT ILI tools, reported cracks are correlated with measurements taken in-the-ditch.<sup>§</sup> Unfortunately, in-the-ditch measurements, using angle beam, time of flight, and other more sophisticated ultrasonic tools have their own reliability problems when estimating the depth and length of individual cracks. The sound pattern reflected from an SCC colony or multiple cracks is complex; however improvements in analysing multiple time-of-flight paths through time resolution, and faster computational methodologies are beginning to help in resolving the depth of individual cracks when multiple cracks are present. The use of complementary NDE techniques also helps, for example magnetic particle inspection (MPI) is much better helping to judge the length of the crack along the surface of the pipe while the most reliable and accurate method for determining crack depth is to progressively remove metal by grinding until the crack is no long present.

Uncertainty in measuring crack depth using an ILI tool and also in-the-ditch methods means that the crack growth rates come with an even greater uncertainty. In determining the interval between ILI runs, engineers use the higher deterioration rate and this higher rate will generate shorter intervals between inspections. For liquids pipelines, it is becoming industry practice (and in fact, a regulated requirement in the United States for) to use a 5 year interval between ILI runs.

Periodic detection and mitigation of large cracks will ensure the reliability of the pipeline and help reach the goal of zero incidents. The reliability of crack detection and sizing will only continue to improve the ILI tool computational resolution as the accuracy of the in-the-ditch measurement resolution techniques also improves. Today's tools are reliably finding and

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<sup>‡</sup> Rosen ROCORR MFL-C Service, In-line high resolution metal loss and narrow axial feature analysis at [www.rosen-group.com](http://www.rosen-group.com)

<sup>§</sup> Yeung, P. et al, "Maximizing MFL ILI Sizing Confidence and Accuracy Using High-resolution Field Measurement Data", Proceedings of the 2012 9th International Pipeline Conference IPC2012 September 24-28, 2012, Calgary, Alberta, Canada



locating the larger cracks. The industry practice of using ILI to inspect for cracks on a 5 year interval may be conservative, but has been locating these cracks well before they develop into a safety item.



## Attachment B

### Dynamic Risk Review and Assessment of Enbridge Line 9B RECOMMENDATIONS

Vs.

### NEB Section 58 Order XO-E101-003-2014 CONDITIONS

A review was completed of the NEB's 30 conditions associated with the approval of Enbridge Pipeline Inc.'s Application, dated November 29, 2012 for the Line 9B reversal and Line 9 capacity expansion project. Those 30 Conditions were compared against the Recommendations made in Dynamic Risk's Review and Assessment of Technical Evaluation for Enbridge Line 9B Reversal (the "Dynamic Risk Review Report for Line 9B").

#### Table of Concordance for NEB Conditions Affecting Pipeline Reliability and Risk

In its Reasons for Decision report, the NEB attached 30 conditions to the approval of Enbridge's application. A review of those 30 conditions was completed, and those conditions that related to pipeline reliability were identified. A Table of Concordance (below) was prepared that compared those pipeline reliability-related conditions against the recommendations made in the Dynamic Risk Review Report for Line 9B.

All but one of the NEB Conditions related to pipeline reliability corresponded with related Recommendations in the Dynamic Risk Review Report for Line 9B, although in general, significant differences in wording exist. The one NEB Condition that didn't correspond to a Dynamic Risk Recommendation was Condition 10. This Condition requires Enbridge to repair all features identified by assessments that meet the CSA Z662-11 repair criteria, and all features that have predicted burst pressures below 125% MOP. No corresponding Recommendation was made in the Dynamic Risk Review Report, since the NEB Condition, as stated, reflects Enbridge's own practices as described in their Pipeline Integrity Engineering Assessment. As such, it was understood that the requirements of this Condition would be met by Enbridge's existing practices.

One Recommendation within the Dynamic Risk Review Report didn't correspond to any NEB Condition. Specifically, in Section 7.6 on page 44, there is a recommendation that the assessments that are performed as part of Enbridge's Pipeline Movement Program should be associated with established reassessment intervals, supported by a rationale basis for the reassessment intervals selected.

**Table of Concordance with NEB Conditions**

<b>NEB Condition Number</b>	<b>Wording of NEB Condition</b>	<b>Corresponding Recommendation from Dynamic Risk Review Report</b>	<b>Report Reference</b>
9	<p>Enbridge shall file with the Board, at least 90 days prior to applying for leave to open (LTO), an Updated Pipeline Engineering Assessment (Updated EA) in a similar format to that of the Line 9B Engineering Assessment. The Updated EA shall be based on the in-line inspections (ILI) and excavations that Enbridge has performed on Line 9 in 2012 and 2013 from Sarnia Terminal to Montreal Terminal. The Updated EA shall include, but not be limited to:</p> <ul style="list-style-type: none"> <li>a) a remaining life analysis, taking into account coincident features, demonstrating that the pipeline between Sarnia Terminal and Montreal Terminal is fit-for-service in the reversed flow direction at Board approved maximum operating pressures (MOPs). If Enbridge chooses to apply different operating pressures for this analysis a justification must be provided;</li> <li>b) a pipeline predicted Rupture Pressure Ratio analysis for integrity threats (including coincident threats) using 100% of the Specified Minimum Yield Strength as reference;</li> <li>c) ILI tool performance, including their probability of detection and probability of sizing;</li> <li>d) Field-tool unity plots for crack and corrosion, including for depth and length; and</li> <li>e) Results of the 2012 annual survey of the cathodic protection system.</li> </ul>	<ul style="list-style-type: none"> <li>• Enbridge should complete an engineering assessment based on the in-line inspection data acquired in the ML-CD segment in 2012, and the follow-up excavations</li> <li>• The engineering assessment referred to above should incorporate a reliability analysis of the in-line inspection data and the follow-up excavations</li> <li>• The reliability analysis should be used to augment Enbridge’s deterministic analysis, as presented in the Pipeline Integrity Engineering Assessment</li> <li>• The reliability analysis should be used to incorporate an understanding of POD for various flaw sizes and relate those correlations to pipeline reliability</li> <li>• The reliability analysis should also address the issue of cracks within deformations, incorporating the capabilities of Enbridge’s threat integration process to enhance POD for that type of damage</li> <li>• The aim of the above analysis should be to demonstrate a satisfactory level of pipeline reliability, based on the use of in-line inspection. If necessary, other assessment methods, including hydrostatic testing, should be considered for the purposes of validating the capability of current in-line-inspection technologies and analysis techniques to impart a satisfactory level of pipeline reliability</li> </ul>	Section 7.2, pp 40-41
10	Based on the MOP and integrity status information used in the Updated EA, at least 30 days prior to applying for LTO, Enbridge shall:		

<b>NEB Condition Number</b>	<b>Wording of NEB Condition</b>	<b>Corresponding Recommendation from Dynamic Risk Review Report</b>	<b>Report Reference</b>
	a) repair all features in the pipeline sections between Sarnia Terminal and Montreal Terminal as identified by additional assessments and/or re-assessments to which Enbridge committed in the Application that meet CSA Z662-11 repair criteria, and all features with a safety factor less than 125% of the MOP, including the defects which triggered the current self-imposed pressure restrictions specified in Enbridge's Line 9B Pipeline Engineering Assessment, regardless of existing operating pressure; and b) file with the Board a report that includes, but is not limited to, a list of features repaired, feature sizes, safety factors prior to repair, and repair date(s).		
11	Enbridge shall file its hydrostatic pressure testing program, pursuant to section 23 of the <i>National Energy Board Onshore Pipeline Regulations</i> (OPR), at least 60 days prior to applying for LTO.	If necessary, other assessment methods, including hydrostatic testing, should be considered for the purposes of validating the capability of current in-line-inspection technologies and analysis techniques to impart a satisfactory level of pipeline reliability	Section 7.2, p. 41
17	Enbridge shall file with the Board, at least 30 days prior to applying for LTO, the updated results of its 2013 Geohazard Study for Line 9. Enbridge should include with the Geohazard Study a summary of its 2012-2013 depth of cover remediation activities.	One recommendation is made with respect to depth of cover. Limited information regarding the most recent depth of cover survey is available, and addresses only certain portions of Line 9B inside Québec. A more comprehensive understanding of the timing and results of the most recent depth of cover survey - especially in areas that are densely populated and that coincide with light-wall pipe - would provide greater assurance that	Section 7.3, pp 41-42

<b>NEB Condition Number</b>	<b>Wording of NEB Condition</b>	<b>Corresponding Recommendation from Dynamic Risk Review Report</b>	<b>Report Reference</b>
		this threat is being adequately managed.	
18	<p>Enbridge shall file with the Board for approval, at least 90 days prior to applying for LTO, a Project-specific Watercourse Crossing Management Plan (WCMP) to establish a management plan identifying the current watercourse crossing conditions and demonstrating how Enbridge will proactively manage watercourse crossings along the existing line.</p> <p>The WCMP shall contain, but not be limited to:</p> <ol style="list-style-type: none"> <li>a) criteria, and rationale for developing such criteria, used to identify major watercourse crossings along Line 9, and such criteria shall meet or exceed CSA Z662-11, clause 4.4.8, note (2);</li> <li>b) a tabular inventory of:             <ol style="list-style-type: none"> <li>i. all watercourse crossings along Line 9, from Sarnia Terminal to Montreal Terminal;</li> <li>ii. those watercourse crossings which do not meet the criteria, with a clear indication of which criteria are not met (for each crossing);</li> <li>iii. those watercourse crossings which do meet the criteria; and</li> <li>iv. for each watercourse crossing that meets the criteria, the proximity to downstream water bodies, critical infrastructure and environmentally significant areas;</li> </ol> </li> <li>c) the location and frequency of monitoring activities, on both a project-wide scale (e.g., fly-overs) and a local scale (e.g., site visits);</li> <li>d) feedback mechanisms in place to track and update the condition of the crossings within the Environmental</li> </ol>	<ul style="list-style-type: none"> <li>• The heightened environmental consequences associated with water crossings warrants the inclusion of the following essential elements within Enbridge’s Water Crossing Management Plan:             <ul style="list-style-type: none"> <li>○ The location and frequency of monitoring activities for specific water crossings;</li> <li>○ A description of possible hazards at specific water crossings; and,</li> <li>○ A description of specific remedial actions that would be implemented in response to each hazard</li> </ul> </li> </ul>	Section 7.6, p. 44



<b>NEB Condition Number</b>	<b>Wording of NEB Condition</b>	<b>Corresponding Recommendation from Dynamic Risk Review Report</b>	<b>Report Reference</b>
	<p>Protection Program, as degraded conditions are identified from monitoring activities;</p> <p>e) a description of possible degraded crossing conditions that may occur and their relative risk; and</p> <p>f) a description of how environmental risks to watercourse crossings will be managed, including provision of a responsibility chart for decisions and the hierarchy of decision points identifying which remedial actions would be implemented, for which degraded conditions, and under what timeframes.</p>		
19	<p>Enbridge shall submit to the Board, prior to applying for LTO, a plan to manage cracking features in the pipeline section between Sarnia Terminal and Montreal Terminal. This plan must include the timeline associated with the assessment methodology, and the rationale for selecting the timeline.</p>	<ul style="list-style-type: none"> <li>• Enbridge should complete an engineering assessment based on the in-line inspection data acquired in the ML-CD segment in 2012, and the follow-up excavations</li> <li>• The engineering assessment referred to above should incorporate a reliability analysis of the in-line inspection data and the follow-up excavations</li> <li>• The reliability analysis should be used to augment Enbridge’s deterministic analysis, as presented in the Pipeline Integrity Engineering Assessment</li> <li>• The reliability analysis should be used to incorporate an understanding of POD for various flaw sizes and relate those correlations to pipeline reliability</li> <li>• The reliability analysis should also address the issue of cracks within deformations, incorporating the capabilities of Enbridge’s threat integration process to enhance POD for that type of damage</li> <li>• The aim of the above analysis should be to demonstrate a satisfactory level of pipeline reliability, based on the use of in-line inspection. If necessary, other assessment methods, including hydrostatic testing, should be</li> </ul>	<p>Section 7.2, pp 40-41</p>

<b>NEB Condition Number</b>	<b>Wording of NEB Condition</b>	<b>Corresponding Recommendation from Dynamic Risk Review Report</b>	<b>Report Reference</b>
		considered for the purposes of validating the capability of current in-line-inspection technologies and analysis techniques to impart a satisfactory level of pipeline reliability	
25	Enbridge shall file with the Board for approval, within 12 months of being granted LTO, an update to the WCMP (WCMP Update), reporting the data which will be used to establish the current watercourse crossing conditions to be used in informing the Plan into the future. The WCMP Update shall contain, but not be limited to: <ol style="list-style-type: none"> <li>a) a reiteration of both the criteria used to identify major watercourse crossings along Line 9, from Sarnia Terminal to Montreal Terminal, and the tabular inventory including:                             <ol style="list-style-type: none"> <li>i. all watercourse crossings along Line 9, from Sarnia Terminal to Montreal Terminal;</li> <li>ii. those watercourse crossings which do not meet the criteria, with a clear indication of which criteria are not met (for each crossing);</li> <li>iii. those watercourse crossings which do meet the criteria; and</li> <li>iv. for each watercourse crossing that meets the criteria, the proximity to downstream water bodies, critical infrastructure and environmentally significant areas.</li> </ol> </li> <li>b) for crossings which meet the criteria (listed in a)iii) above), provide:                             <ol style="list-style-type: none"> <li>i. channel-specific seasonal hydrographs (1 yr return);</li> <li>ii. bankfull profiles at crossing locations;</li> </ol> </li> </ol>	<ul style="list-style-type: none"> <li>• The Water Crossing Management Plan should be supported by an evaluation of watercourse-specific information, including hydrographic data, river profiles at crossing locations, sediment characteristics in the immediate vicinity of the crossing, depth of cover, geotechnical assessments of adjacent banks, floodplain maps, scour assessments and flood frequency analysis.</li> </ul>	Section 7.6, p. 44

<b>NEB Condition Number</b>	<b>Wording of NEB Condition</b>	<b>Corresponding Recommendation from Dynamic Risk Review Report</b>	<b>Report Reference</b>
	<ul style="list-style-type: none"> <li>iii. sediment characteristics immediately up- and downstream of the crossing location;</li> <li>iv. depth of cover and geotechnical assessments of the adjacent banks, to a distance of 100 m;</li> <li>v. floodplain delineation maps; and</li> <li>vi. scour assessments and flood frequency analyses at each watercourse crossing based on 50-yr, 100-yr, and regulatory storm flood volumes.</li> <li>vii. a description of how the data collected will be used to address the requirements to manage environmental risks, including the effects of the environment on watercourse crossings;</li> <li>viii. a schedule for future updates, incorporating monitoring activities provided in <b>Condition 18</b>, frequency of additional data collection and analysis, as well as the protocol for alterations or refinements to the Plan based on the updated watercourse conditions; and</li> <li>ix. evidence of consultation with Environment Canada, the Toronto and Region Conservation Authority and other appropriate provincial, regional and municipal authorities regarding the WCMP (<b>Condition 18</b>) and the WCMP Update.</li> </ul>		
27	<p>Enbridge shall file with the Board, within 18 months following the receipt of Board approval for LTO, a proposed long-term integrity improvement plan to mitigate and monitor remaining ILI-reported corrosion (internal and external), geometry and cracking features in the pipeline sections between North Westover Station and the Montreal Terminal indicating, but not limited to, their timelines, the rationale for selecting those</p>	<ul style="list-style-type: none"> <li>• Enbridge should complete an engineering assessment based on the in-line inspection data acquired in the ML-CD segment in 2012, and the follow-up excavations</li> <li>• The engineering assessment referred to above should incorporate a reliability analysis of the in-line inspection data and the follow-up excavations</li> <li>• The reliability analysis should be used to augment</li> </ul>	<p>Section 7.2, pp 40-41</p>

<b>NEB Condition Number</b>	<b>Wording of NEB Condition</b>	<b>Corresponding Recommendation from Dynamic Risk Review Report</b>	<b>Report Reference</b>
28	<p>features, and the planned re-inspection interval.</p> <p>Enbridge shall file with the Board for approval, within 18 months following the receipt of Board approval for LTO, an updated Deterministic Remaining Life evaluation for each segment (i.e., pump station to pump station) of Line 9 from the Sarnia Terminal and the Montreal Terminal. This assessment should take into account (but not be limited to) the results of the most recent ILI runs and excavations, coincident imperfections, the Board approved MOPs, and actual operating pressure cycling dataset for the most aggressive periods since the reversal.</p>	<p>Enbridge’s deterministic analysis, as presented in the Pipeline Integrity Engineering Assessment</p> <ul style="list-style-type: none"> <li>• The reliability analysis should be used to incorporate an understanding of POD for various flaw sizes and relate those correlations to pipeline reliability</li> <li>• The reliability analysis should also address the issue of cracks within deformations, incorporating the capabilities of Enbridge’s threat integration process to enhance POD for that type of damage</li> <li>• The aim of the above analysis should be to demonstrate a satisfactory level of pipeline reliability, based on the use of in-line inspection. If necessary, other assessment methods, including hydrostatic testing, should be considered for the purposes of validating the capability of current in-line-inspection technologies and analysis techniques to impart a satisfactory level of pipeline reliability</li> </ul>	