LINE 9B REVERSAL AND LINE 9 CAPACITY EXPANSION PROJECT

PIPELINE INTEGRITY ENGINEERING ASSESSMENT

Submitted to:

NATIONAL ENERGY BOARD

Prepared by:

Enbridge Pipelines Inc. Pipeline Integrity Department

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GLOSSARY OF TERMS

AFD	Axial Flaw Detection
bpd	barrels per day
CD	Cardinal Station
CF	Crack Field
CGRs	Corrosion Growth Rates
CL	Crack-Like
CP	Cathodic Protection
CVN in ft-lbs	Charpy V-Notch Value
D/t	Diameter over thickness
DICP	Dents In Close Proximity
DNV	Det Norske Veritas (Canada) Ltd.
EA	Engineering Assessment
Enbridge	Enbridge Pipelines Inc.
FFS	Fitness For Service
GE	General Electric
HCA	High Consequence Area
HL	Hilton Station
ILI	In-Line Inspection

GLOSSARY OF TERMS

IMU	ILI Inertial Measuring Unit
IPC	Internal Pipe Corrosion
IR	Voltage
J_C	J-fracture toughness
Line 9	Lines 9A and 9B
Line 9 Reversal Phase I Project	Reversal of the 194-kilometre segment of Line 9 between Sarnia Terminal and North Westover Pump Station (“Line 9A”) pursuant to Order XO-E101-010-2012
Line 9A	194-kilometre segment of Line 9 between Sarnia Terminal and North Westover Station
Line 9B	639-kilometre segment of Line 9 from North Westover Station to Montreal Terminal
Line 9B Reversal and Line 9 Capacity Expansion Project	Proposal to reverse a section of Line 9 between North Westover and Montreal and concurrently expand the overall annual capacity of Line 9 from Sarnia to Montreal
m^3	cubic metre
MAD	Multiple apexes
MAOP	Maximum Allowable Operating Pressure
MDMP	Mechanical Damage Management Plan
MFL	Magnetic Flux Leakage
ML	Montreal Terminal

GLOSSARY OF TERMS

MLV	Mainline Valves
MOP	Maximum Operating Pressure
NACE	National Association of Corrosion Engineers
ND	Not Determinable
NDE	Non-Destructive Examination
NEB	National Energy Board
NL	Notch-Like
NW	North Westover Station
PAP	Public Awareness Program
PCRs	Polarization Cell Replacements
PE Tape	Polyethylene Tape
Pf	Predicted Failure pressure
PFPR	Predicted Failure Pressure Ratios
POD	Probability of Detection
POS	Probability of Sizing
PRCI	Pipeline Research Council International
Project	Line 9B Reversal and Line 9 Capacity Expansion Project
RCC	Rainflow Cycle Counting

GLOSSARY OF TERMS

RMUs	Remote Monitoring Units
ROW	right of way
RPR	Rupture Pressure Ratio
S&W	Sediment and Water
SA	Sarnia Terminal
SCC	Stress Corrosion Cracking
SMYS	Specified Minimum Yield Strength
TB	Terrebonne Station
USCD	Ultrasonic Crack Detection
USWM	Ultrasonic Wall Measurement
UT	Ultrasonic
WT	Wall Thickness

1. EXECUTIVE SUMMARY

This engineering assessment ("EA") completed by Enbridge Pipelines Inc. ("Enbridge") demonstrates that the Line 9B Reversal and Line 9 Capacity Expansion Project ("Project"), including the increase in capacity of Lines 9A and 9B ("Line 9") and the possible addition of heavy crude products to Line 9, can proceed as proposed. The subject pipelines, specifically the 194-kilometre segment of Line 9 between Sarnia Terminal ("SA") and North Westover Station ("NW") ("Line 9A") and the 639-kilometre segment of Line 9 from NW to Montreal Terminal ("ML") ("Line 9B"), can continue to operate in a safe and reliable condition irrespective of flow direction, product transported or annual pipeline capacity as specified in the application. This assessment is supported both by the results of the EA for Line 9B as presented herein, as well as by the results of the EA for Line 9A and related responses to Information Requests submitted during National Energy Board ("NEB") Proceeding OH-005-2011 for the Line 9 Reversal Phase I Project.

Corrosion

The established programs that manage internal and external corrosion on the Enbridge pipeline system are aligned to meet or exceed the current NEB-approved Maximum Operating Pressure ("MOP") along the length of the entire Line 9 pipeline. As the Project does not involve a change to the NEB-approved MOP, corrosion can be adequately managed through the corrosion management program of the subject pipeline. The results of the EA presented herein support this assessment.

Cracking Threat

The established programs that manage fatigue cracking and environmentally assisted cracking, such as Stress Corrosion Cracking ("SCC") and fatigue corrosion, on the Enbridge pipeline system are aligned to meet or exceed the current MOP along the length of the entire Line 9 pipeline. As the Project does not involve a change to the licensed MOP , the cracking threats can be adequately managed though the crack management program of the subject pipeline. The results of the EA presented herein support this assessment.

Mechanical Damage

The established programs that manage the risk associated with mechanical damage, including third party damage, will not be affected by the Project, and the mechanical damage threat on the entire Line 9 is not considered to increase due to the proposed flow reversal on this pipeline. The results of the EA presented herein support this assessment.

Planned Activities Prior to Flow Reversal

In addition to the EA and related Information Requests responded to for the Line 9 Reversal Phase I Project and the EA for Line 9B presented herein, which reassure that Line 9 can be operated in a safe and reliable condition irrespective of flow direction, and in consideration of the product types and annual capacity proposed per the Project application, Enbridge plans to complete the following integrity work prior to the flow reversal of Line 9B in 2014:

- conduct a comprehensive in-line inspection ("ILI") program;

- evaluate the ILI data to determine what, if any, line rehabilitation activities are required to maintain the integrity of the pipeline; and
- execute required excavations and line rehabilitation to maintain line integrity at required operating parameters.

2. PROJECT INFORMATION

2.1 Project Background

The Project proposes to reverse a section of the Enbridge Line 9 between NW and ML ("Line 9B") and concurrently expand the overall annual capacity of Line 9 from Sarnia ("SA") to ML to accommodate our customers' requests for greater pipeline capacity and access to North American crude.

This 762 mm (NPS 30) pipeline, as shown in the schematic in Figure 2.1, was originally constructed in 1975, placed into service in 1976 and originally flowed in an eastward direction. The flow of the pipeline was reversed to a westward direction in 1999 following the National Energy Board ("Board" or "NEB") OH-2-97 proceeding and pursuant to Order XO-J1-34-97.

On July 27, 2012, the NEB approved a standalone application by Enbridge for the reversal of the 194-kilometre segment of Line 9A pursuant to Order XO-E101-010-2012 (the "Line 9 Reversal Phase I Project").

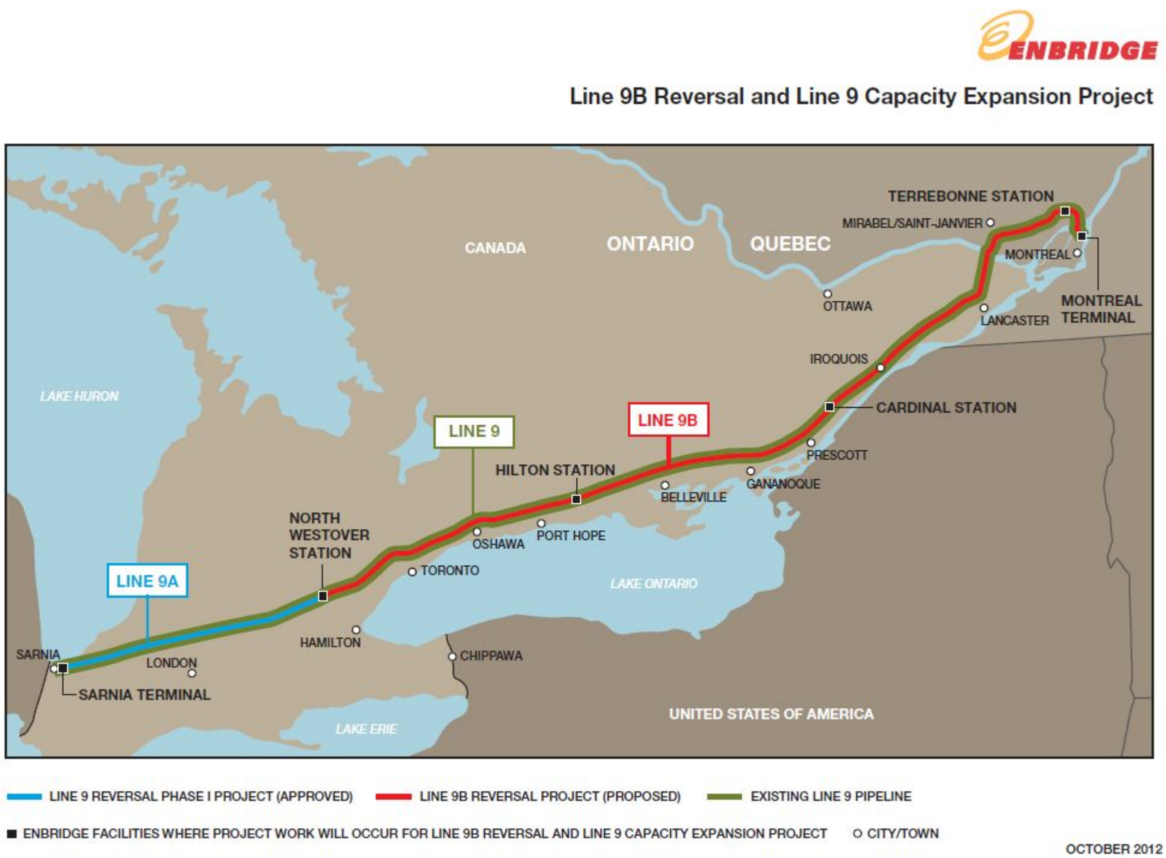


Figure 2.1 - The Project System Map

2.2 Engineering Assessment

Thorough review of the Line 9 Reversal Phase I EA, in consideration of the increased annual capacity and transportation of heavy crude on Line 9A as a result of the Project, confirms the conclusions reached in that EA under the operating parameters proposed for the Project. The EA prepared for the Line 9 Reversal Phase I Project and related Information Request responses are therefore applicable to the Project. The Line 9A EA and related Information Request responses can be found on the NEB website under Proceeding OH-005-2011, using the following NEB reference numbers:

- EA - A2C0V6;
- Appendices – A2C0V7 and A2C0V8;
- Information Request No. 3 – A39519, A39735, and A40058; and
- Information Request No. 5 – A41505.

This EA, which provides details in relation to Line 9B, was prepared in accordance with Section 3.3 of CSA Z662-11 "Oil and Gas Pipeline Systems" and consists of the following:

- review of historical and pipeline integrity management records;
- threat identification; and
- Fitness For Service ("FFS") assessment and effect of the line reversal on the identified threats.

The review of historical records included consideration of the design, materials, construction, pressure testing, operations, inspection and maintenance histories. The review of pipeline integrity management records includes:

- an evaluation of the findings from the metal loss inspection conducted in 2006/2007;
- an evaluation of the findings from the geometry inspection conducted in 2000/2005/2007; and
- an evaluation of the findings from the crack inspections conducted in 2004/2005/2006

2.3 Engineering Assessment Team

This EA has been prepared by members of the Pipeline Integrity Department at Enbridge. These team members are listed in Table 2-1.

Table 2-1 - Pipeline Integrity Team Members

Person	Department
Trevor Place Len Krissa Cristin Mieila	Integrity Planning, Pipeline Integrity Corrosion Programs
Saheeh Akonko	Integrity Planning, Pipeline Line Integrity Crack Programs
Greg Sasaki Milan Sen	Integrity Planning, Pipeline Integrity Deformation Programs
William Boorse	Pipeline Integrity Projects, Pipeline Integrity Infrastructure
David Weir Yangping Li	Operational Risk Management, Risk Management Modeling

3. PIPELINE RECORDS

Enbridge has reviewed records that describe the condition of Line 9 from NW to ML including design, materials, construction, pressure testing, operations, inspection and maintenance histories. This review did not identify any areas of potential concern associated with the proposed reversal in flow, the addition of heavy crude products or the proposed increase in throughput.

3.1 Pipeline Specifications

Table 3-1 provides a summary of the pipe properties for Line 9B, which is constructed with Grade X52 pipe and has a wall thickness ("WT") varying between 6.35 and 12.7 mm. Table 3-1 also provides the NEB approved MOPs between NW, Hilton ("HL"), Cardinal ("CD") and ML.

Table 3-1 - Pipe Properties and Test Pressures

<table>
<tr><th>Pipe Properties</th><th colspan="2">ML-NW</th></tr>
<tr><td>Diameter</td><td colspan="2">NPS 30 (762 mm)</td></tr>
<tr><td>WT</td><td colspan="2">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</td></tr>
<tr><td>* Grade</td><td colspan="2">API 5L X52 (359 MPa)</td></tr>
<tr><td>Construction Date</td><td colspan="2">1975</td></tr>
<tr><td>Long Seam Weld Type</td><td colspan="2">Double Submerged Arc Weld</td></tr>
<tr><td>Manufacturer</td><td colspan="2">Stelco</td></tr>
<tr><td>Pipeline Length</td><td colspan="2">639 km</td></tr>
<tr><td>Coating</td><td colspan="2">Single Layer Polyethylene Tape (“PE Tape”)</td></tr>
<tr><td rowspan="2">Approved Point MAOP**</td><td>NW-HL
(KP 3002.312 – KP 3214.375)</td><td>5915 kPa @ KP 3023.973
4547 kPa @ KP 3093.529
4452 kPa @ KP 3136.644
4656 kPa @ KP 3182.478
4335 kPa @ KP 3213.957</td></tr>
<tr><td>HL-CD
(KP 3214.375 – KP 3430.365)</td><td>6040 kPa @ KP 3237.067
5396 kPa @ KP 3291.623
4856 kPa @ KP 3354.967
4775 kPa @ KP 3430.402</td></tr>
<tr><td></td><td>CD-ML
(KP 3430.365 – 3636.474)</td><td>4747 kPa @ KP 3483.119
4783 kPa @ KP 3527.473
4557 kPa @ KP 3601.647
4778 kPa @ KP 3616.533
2498 kPa @ KP 3636.470</td></tr>
</table>

* Manufactured in accordance with CSA Z245.1-1971 and CSA Z245.2-1971

** 5 March 1999 Leave to Open (File No: 3400-E1010-86)

3.1.1 Mechanical Properties

The mechanical properties for Line 9, including tensile strengths and toughness values, are contained within the Enbridge Line 9 Material Test Reports; however, for the purpose of fracture mechanics and failure pressure assessments, Enbridge will generally follow a more conservative approach and will assume much lower material toughness for both the pipe body and long weld seam.

3.2 Operating Information

3.2.1 Operational Background

Line 9 from ML to SA was constructed in 1975 and placed into service in 1976 as part of the Enbridge pipeline system design and built to transport Western Canadian crude oil from Sarnia to Montreal. The pipeline was hydrostatically tested in 1976 to satisfy the construction hydrostatic test requirements and to achieve the maximum hydrostatic test profile accepted for service by the NEB to operate at or below 80 percent of the proven test pressure.

Line 9 was deactivated in July 1991, pursuant to NEB Order TO-4-92, and reactivated two years later, pursuant to NEB Order TO-5-92, in July 1993. During this period, the line remained purged with nitrogen at a constant pressure of 200 kPa (29 psi) and was protected externally with Cathodic Protection (“CP”).

A second hydrotest was conducted on Line 9 in 1997 as part of the OH-2-97 Line 9 Reversal Project and pursuant to Order X0-JI-34-97. Following the reversal, Line 9 has operated in westward flow towards SA transporting condensate, sweet and sour crude oil. The pipeline has experienced operating pressures below MOP and minimal pressure cycling as describe in detail in Section 4.3 of this analysis due to the relatively low throughput requirements. Pipeline integrity has been maintained through a combination of ILI, pressure restrictions and line rehabilitation.

Appendix A shows a system schematic of Line 9 from ML to SA in the current westbound service configuration.

3.2.2 Planned Operating Mode

Subject to approval, upon reversal in spring 2014, Line 9, including Lines 9A and 9B, is planned to transport 47, 696 m^3/day (300,000 barrels per day (“bpd”)) on average annually, based on commercial demand.

3.2.3 Future Operating Pressures

Subject to approval, upon flow reversal, the NEB-approved MOP between NW to ML will be maintained at the pressures specified in the March 1999 Line 9 leave to open document, summarized above in Table 3-1.

3.3 Welding Inspection Construction Records

Circumferential welds were completed and inspected at the time of construction to the existing CSA Z183-73 code requirements.

3.4 Operating and Maintenance Records

3.4.1 Hydrotest Failures

There were no leaks or ruptures on Line 9 during the last hydrostatic test conducted in 1997.

3.4.2 In-Service Leaks and Ruptures

The mainline segment of Line 9 from ML to NW has experienced a total of 12 mainline leaks and one mainline rupture since initial construction, which occurred between 1978 and 2005, and all of which have been permanently repaired. These incidents are listed below in Table 3-2.

Table 3-2 - In service Leaks and Ruptures: Line 9 (NW – ML)

Date	Cause	Location		Type
		KP	MP	
11/3/2005	Mechanical Damage	3354.97	2084.68	Leak
8/10/1999	Dent	3423.88	2127.5	Leak
2/25/1997	Dent	3458.98	2149.31	Leak
11/28/1996	Dent	3471.69	2157.21	Leak
7/14/1993	Corrosion	3044.08	1891.505	Leak
2/23/1993	Third party damage	3578.12	2223.34	Leak
8/5/1993	Corroded Densitometer	3633.91	2258.01	Leak
1/26/1991	Crack	3036.82	1886.99	Leak
3/30/1988	Dent	3578.12	2223.34	Leak
1/6/1979	Dent	3004.69	1867.03	Leak
4/13/1979	Dent	3466.37	2153.9	Leak

6/14/1978	Former third party damage	3472.35	2157.62	Leak
6/14/1978	Mechanical Damage	3636.36	2259.53	Rupture

3.4.3 Line Inspection History

A summary of the ILI history is provided in Table 3-3, which includes Magnetic Flux Leakage ("MFL") and Ultrasonic Wall Measurement ("USWM") for metal loss ILI and Ultrasonic Crack Detection ("USCD") for crack ILI. Additional ILIs , including MFL, USWM, USCD Caliper and Axial Flaw Detection ("AFD"), have been executed in 2012 and are, as of November 2012, under vendor assessment. An additional USCD is scheduled for January 2013.

Table 3-3 - ILI History: Line 9 (NW – ML)

Year	Segment	Vendor	Tool
1975	NW-HL HL-CD CD-ML	TDW	Caliper
1976	NW-HL HL-CD CD-ML	IPEL	Geometry
1977	CD-ML	Vetco	Metal Loss (MFL)
1978	NW-HL HL-CD CD-ML	TDW	Caliper
1979	NW-HL HL-CD CD-ML	TDW	Caliper
1979	NW-HL HL-CD CD-ML	IPEL	Metal Loss (MFL)
1980	NW-HL HL-CD CD-ML	TDW	Caliper

Year	Segment	Vendor	Tool
1986	NW-HL HL-CD CD-ML	TDW	Caliper
1987	CD-ML	IPEL	Geometry Metal Loss (MFL)
1988	NW-HL	TDW	Caliper
1988	NW-HL HL-CD	Tubescope	Metal Loss (MFL)
1988	CD-HL	PTX	Geometry
1990	NW-HL HL-CD CD-ML	Nowsco	Geopig
1990	NW-HL	Tubescope	Metal Loss (MFL)
1995	NW-HL HL-CD CD-ML	Nowsco	Geopig
1995	NW-HL HL-CD CD-ML	British Gas	Metal Loss (MFL)
1999	CD-ML	BJ	Geopig
2000	HL-CD	BJ	Geopig
2000	HL-CD CD-ML	Pipetronix	Metal Loss (UT)
2001	HL-NW	GE-PII	USWM
		BJ	Geopig
		Ctool	Caliper
2002	CD-HL	GE-PII	USWM
		BJ	Geopig
2004	ML-CD	GE-PII	USWM
		BJ	Geopig
		GE-PII	USCD

Year	Segment	Vendor	Tool
		Ctool	Caliper
2005	HL-NW	GE-PII	USCD
		GE-PII	USWM
		BJ	Geopig
2006	CD-HL	GE	USCD
		GE	USWM
		BJ	MFL Vectra
2007	ML-CD	GE GE	MFL Caliper
2007	HL-NW	GE	USWM
2012	HL-NW	GE	Calscan XR
2012*	ML-CD	GE	Caliper MFL USCD USWM
		Rosen	AFD
2012*	CD-HL	GE	Caliper MFL USCD USWM
		Rosen	AFD
2012*	HL-NW	GE	USCD USWM
		Baker Hughes	Gemini (MFL and Caliper)
		Rosen	AFD
2013*	CD-HL	GE	USCD

*ILI executed or planned but not yet fully assessed by ILI vendors, and therefore not included in this EA.

3.4.4 Excavation and Repairs

Within Enbridge, all ILI programs include repair and correlation excavations based on the most recent defect assessment criteria being utilized. Tables 3-4 through 3-6 list the number and types of features from the most recent ILIs that met excavation criteria from ML to NW.

Table 3-4 - Excavation and Repairs: Line 9 (ML-CD)

Targeted Feature Type	Total	Sleeve Repairs	Recoats	Cutouts
Corrosion	34	9	25	0
Dent	14	9	5	2
Crack	12	3	9	0
Total	**60**	**21**	**39**	**0**

Table 3-5 - Excavation and Repairs: Line 9 (CD-HL)

Targeted Feature Type	Total	Sleeve Repairs	Recoats	Cutouts
Corrosion	3	1	2	0
Dent	0	0	0	1
Crack	63	35	28	0
Total	**66**	**36**	**30**	**0**

Table 3-6 - Excavation and Repairs: Line 9 (HL-NW)

Targeted Feature Type	Total	Sleeve Repairs	Recoats	Cutouts
Corrosion	20	10	10	0
Dent	2	1	1	0
Crack	20	2	18	0
Total	**42**	**13**	**29**	**0**

3.4.5 Operating Risk Management

The Operational Risk Management Pipeline Risk Assessment Model integrates the results of the corrosion, cracking, and mechanical damage analyses contained in the Pipeline Integrity Management Plan with (a) other potential pipeline threats (including third party damage, ground movement, natural forces, incorrect operations and appurtenances) and (b) the potential consequences of these pipeline threats (including impacts on population, environment, and business).

The integration of this data yields a relative comparison of the risk for the pipeline (using 300-metre segmentation). These results are reviewed annually to determine the need for mitigation activities in addition to those that are already in place for individual threats driving the identified risks.

The risk assessment results for the Line 9B Reversal portion of the Project demonstrate minor changes in the likelihood of failure. Susceptibility of the pipeline to external and internal corrosion remains unchanged with the reversal. The susceptibility to cracking potentially increases for those sections of pipe now at the discharge side of the pump and decreases for those sections that are now at the suction side of the pump. Natural forces, system operations, appurtenances, third party and ground movement threats do not change with the proposed reversal. Consequence of failure is not dependent on flow direction and no change in consequence is expected from the Line 9B Reversal.

The increase in Line 9 capacity as a result of the Line 9 Capacity Expansion portion of the Project results in a minor increase in assessed risk for 0.9% of the pipeline.

In summary, the reversal of Line 9B will result in minor increases of risk to the operation of the pipeline at the discharge side of the pump stations (North Westover, Hilton, Cardinal and Terrebonne) and in minor decreases of risk to the operation of the pipeline at the suction side of the pump stations (Hilton, Cardinal, Terrebonne and Montreal). The increase in capacity to Line 9 as a whole yields a minor increase in risk for 0.9% of the pipeline. Overall, the changes in risk results as a result of the Project are minimal, and the risk control and mitigation strategies currently being executed by Enbridge manage these risks.

Appendix B contains the Pipeline Compliance and Risk Management Pipeline Risk Assessment for the Project.

4. FFS ASSESSMENTS

4.1 Threat Identification

Reversing the flow direction and operating pressure profile of this pipeline, as well as increasing the annual capacity, do not require a change to the existing MOP. However, the flow reversal will result in segments of the pipeline being operated at higher pressures than the previous operating levels. As a result, a threat identification assessment has been conducted to identify and assess any features and failure mechanisms that may become more susceptible due to the change in pressure profile. Using the terminology in CSA Z662-11 Annex H (H.2.6.1), the effect of the line reversal was evaluated on the primary causes of pipelines failures identified below:

- metal loss;
- cracking;
- external interference;
- material or manufacturing;
- construction; and
- geotechnical failure.

Potential threats identified were evaluated for their suitability for service under reverse flow, and the details of the validation of the individual features and threat mechanisms are described herein.

4.2 Metal Loss

Pipeline metal loss is managed by Enbridge through a series of comprehensive prevention, monitoring and mitigation programs. The external corrosion prevention measures include:

- protective external coating;
- a CP system installed and maintained to Enbridge standards;
- routine ILI using high resolution MFL and Ultrasonic (“UT”) ILI technology; and
- excavation and repair programs.

The internal corrosion prevention, monitoring and mitigation measures include:

- tariff limits on Sediment and Water (“S&W”) content;
- routine monitoring, line cleaning and chemical inhibition (if required);
- oil batch testing;
- routine ILI using high resolution MFL and UT ILI technology; and
- excavation and repair programs.

The above programs have been designed to maintain reliable operation up to the MOP along the entire NW to ML pipeline segment regardless of actual operating pressure at each particular line segment. As such, the proposed reversals of flow and capacity increase do not require any changes to the metal loss management programs. Based upon the metal loss related analysis and assessments summarized herein, it is concluded that the metal loss threat on the line is adequately managed and will continue to be managed at an acceptably low risk level regardless of flow direction and annual pipeline capacity.

4.2.1 External Corrosion Control

External corrosion on Line 9 between ML and NW is prevented through the application of an external single layer PE Tape coating during initial construction and a CP system operated and maintained to industry and Enbridge standards. An annual pipe-to-soil survey is performed to determine the state of the CP system and to evaluate the overall protection level(s). Any areas that exhibit low potential measurements would typically be investigated further utilizing a Close Interval Survey. Rectifier parameters are inspected monthly by Enbridge personnel to comply with CSA Z662-11 and CGA OCC-1-2005 (Control of External Corrosion on Buried Submerged Metallic Piping Systems).

In addition to direct inspections of the CP system as discussed above, locations found to be experiencing high Corrosion Growth Rates (“CGRs”) are compared against CP data in order to identify any locations of compromised CP.

4.2.1.1 Rectifier Replacement and System Upgrades

On the basis of the annual CP performance and monthly rectifier inspections between NW and ML, Enbridge undertakes capital projects to improve protection levels and/or to make the CP infrastructure more reliable and easier to maintain. Any operational issues that arise throughout the year are dealt with immediately to ensure that protection is maintained. A remote monitoring program is in place for Line 9, enabling continual interrogation of rectifier status through cellular or satellite communication. This section of Line 9 within the remote monitoring program region has a total of 22 influencing rectifiers, which are all equipped with remote monitoring units (“RMUs”).

4.2.1.2 Cathodic Protection System Status

The annual CP inspections along the Line 9 corridor are typically performed in the late summer and fall seasons. Current applied “On” and polarized “Off” potentials are obtained using GPS-synchronized current interrupters in conjunction with hand-held electronic high frequency sampling data collection devices. All data is collected by National Association of Corrosion Engineers (“NACE”) certified technicians.

Enbridge evaluates the protection levels of the cathodic systems utilizing primarily the NACE criteria as per SP-0169-2007 (Control of External Corrosion on Underground or Submerged Metallic Piping Systems). The first evaluation is based on the -850mV “Off” polarized potential criterion. Instant “Off” polarized potentials measured with respect to a Cu/CuSO4 reference electrode that are more electronegative than the -850mV threshold indicate that protection is achieved. The second evaluation is based on the 100mV polarization decay criterion. In areas where the -850mV instant off criterion is not achieved, the rectifiers are turned off to allow monitoring of polarization decay. Polarization decay of more than 100mV also indicates that protection is achieved. To obtain proper measurements of polarization decay, extensive areas of the CP system require shutdown for upwards of several weeks; therefore, Enbridge minimizes the use of this criterion to avoid prolonged system outages that may have an effect on the overall protection levels of the pipeline.

A number of factors can influence “On” and “Off” potential readings, including:

- voltage (or “IR”)drops in the soil;
- foreign-generated DC currents;
- capacitive effects;

- chemical environment of the soil; and
- current generated from dissimilar levels of polarization on the same structure.

In order to determine the corrected level of pipeline polarization (i.e. "Off" measurement), all current must be stopped and readings recorded prior to depolarization of the pipeline. The elimination of current is sometimes impossible to achieve using conventional data collection methods. This applies particularly within the Toronto area from KP 3016.781 to KP 3119.517 (MP 1874.541 to MP 1938.378), where it is impractical to interrupt all of the current sources, specifically forced drainage bonds and stray current resulting from Toronto Transit Commission activities. Within this region, since polarized potentials cannot reliably be acquired using conventional survey techniques, an adapted criterion was established by consulting corrosion specialists where an "On" potential equal to or more negative than -1000mV would constitute adequate CP. This criterion has historically proven to be effective based upon low corrosion incidence identified through ILI metal loss programs. Additionally, existing coupon monitoring within this region demonstrates that adequate protection is being accomplished and meets standard criteria requirements. Further efforts at the regional level are being made to expand coupon monitoring within this locality to provide a more comprehensive evaluation of CP effectiveness. As part of the annual adjustive survey, cathodic levels are also monitored for a 24-hour period using stationary data loggers to record variations in pipe-to-soil potentials within this section.

Enbridge has implemented, and continues to execute, a program of utilizing CP coupon monitoring to allow for the recording of IR free potentials in the areas of foreign CP system influence (eliminating the need to interrupt foreign owned CP systems) and/or the measurement of 100mV decay of the coupon rather than the pipeline. The installation of additional external corrosion coupons at select locations is being considered to further supplement the cathodic monitoring program by enabling capability for more comprehensive evaluation of protection levels.

Line 9B has a common right-of-way and interconnection with Line 8 from Westover to Millgrove Junction, and Polarization Cell Replacements ("PCRs") at select motorized valve sites have improved the overall performance of the shared CP systems. Overall, CP effectiveness and efficiency have increased through implementation of PCRs on a number of Mainline Valves ("MLVs"), and provision is being made for the installation of additional PCRs at all remaining applicable MLV sites.

The most recent CP information available to date is the 2011 annual adjustive survey, in which pipe-to-soil potentials were determined at 519 separate locations along the right-of-way between NW and ML.

Upon completion of the survey, the majority of the readings (518/519) met the aforementioned criteria, with the exception of one location. Locations original found as marginal or inadequately protected were resolved with appropriate adjustment of influencing rectifiers at the time of the survey.

2011 survey results revealed that a sub-criterion measurement (-815mV) was recorded at KP 3217.046 (MP 1998.98), based upon the -850mV "Off" threshold. Follow-up testing at this location has confirmed that 100mV polarization is being achieved. A rectifier outage which significantly influenced three readings between KP 3385.748 and KP 3392.100 (MP 2103.806 and MP 2107.753) occurred during the survey. This temporary interruption was less than one month in duration, where operation and protection levels were restored shortly after the deficiency was identified.

The portion of the pipeline from Oshawa to Cornwall is electrically bonded to TCPL and, since the 2009 evaluation, rectifier outputs have been optimized. This has improved overall protection throughout this area. The installation of additional coupon test stations is being considered within this segment to provide a more comprehensive assessment of the system's performance.

During the 2011 survey, a total of 28 sub-criterion and marginal readings were recorded between KP 3618.518 and KP 3636.284 (MP 2248.443 and MP 2259.482). Additional investigation at the time of the survey revealed that the PCR located at KP 3627.083 (MP 2253.765) (MLV 47) was inadvertently bypassed during unrelated electrical work. Following the survey, the PCR at MLV 47 was relocated and configured to re-establish electrical isolation, immediately returning potentials throughout this segment back to historically protected levels.

4.2.1.3 Cased Crossing Management

Line 9B has a total of 208 cased crossings between NW and ML that were identified as part of Enbridge's ongoing CP monitoring program. These casings were originally installed to provide mechanical protection from road and railway crossings and incorporate electrically isolating spacers and end seals that separate the carrier pipe from the casing. Over time, the integrity of the end seals can degrade, allowing for the ingress of groundwater which can potentially lead to corrosion. Pipe movement due to settling and degradation of the isolating spacers may also allow for potential contact of the casing to the carrier pipe, resulting in an electrical short. Failed end seals and electrical shorts can present an elevated risk of external corrosion for the section of piping located within the cased crossing.

During the annual CP survey, potential measurements are taken on all casings. These readings are then compared to the pipeline potentials at the same locations. A potential difference of 10mV or more is an indication that the carrier pipe is electrically isolated, minimizing the risk of external corrosion within the casing. The casing potential readings recorded on all 208 casings from ML to NW indicated a minimum potential difference of 115mV, which indicates that the casings are still electrically isolated from the carrier pipe throughout this section. However, the Highway 15 cased crossing at MP 2074.3 within the Oshawa region is exhibiting indications of possible electrolytic coupling. Additional testing is planned to determine whether remediation is necessary, but the most recent metal loss ILI results indicate no external corrosion is being experienced at this location.

This pipeline contains additional casings and half casings that were originally installed and subsequently removed, or filled with dielectric wax as part of historic casing rehabilitation programs. Since there are no above-ground appurtenances or test leads to measure from, these are no longer part of the CP monitoring program and are managed through Enbridge ILI and excavation programs. The locations, as identified through MFL ILI programs, have been communicated to regional Operations corrosion control personnel; provisions are being made to re-introduce them back into the annual CP survey.

The corrosion condition of carrier pipe under casings is monitored as part of all Enbridge metal loss ILI programs.

4.2.2 Corrosion Management Approach

4.2.2.1 Monitoring

Detailed information regarding the integrity condition of the pipeline is obtained through high resolution metal loss ILIs. Table 4-1 provides a list of metal loss inspections completed to date.

Table 4-1 - Metal Loss ILI History: Line 9 (ML-NW)

Year	ML-CD	CD-HL	HL-NW
1978	Velco	-	-
1979	IPEL MFL	IPEL MFL	IPEL MFL
1986	-	-	Tuboscope MFL
1987	IPEL MFL	-	-
1988	-	Tuboscope MFL	Tuboscope MFL
1995	GE-PII MFL	GE-PII MFL	GE-PII MFL
2000	-	GE-PII USWM	-
2001	-	-	GE-PII USWM
2004	GE-PII USWM	-	-
2005	-	-	GE-PII USWM
2006	-	BJ Vectra MFL GE-PII USWM	-
2007	GE-PII MFL	-	GE-PII MFL

4.2.2.2 Excavation and Repair Criteria

Metal loss features identified by the metal loss ILIs that equal or fall below a Rupture Pressure Ratio (“RPR”) value of 1.0 or have depth equal to or greater than 50% of the pipe WT are selected for excavation and assessment. Metal loss features meeting the repair criteria, as described in Table 4-2, are repaired with full encirclement sleeves.

Table 4-2 - Enbridge Metal Loss Repair Criteria

Metal Loss	RPR and %WT Depth	Remedial Action
External	RPR ≤ 1.0 Depth ≥ 80%	Repair
	RPR > 1.0 Depth < 80%	Recoat
Internal	RPR ≤ 1.0 Depth ≥ 50%	Repair

All features identified by the most recent metal loss inspections and excavation programs that met the required repair criteria have been excavated, assessed and repaired.

4.2.3 Metal Loss Incidence Charts

In order to provide a qualitative description of the metal loss distribution along the pipeline, the location and severity of metal loss anomalies as reported by the most recent ILI have been plotted. The charts are useful in identifying any locations along the pipeline that have unusual patterns of metal loss density or severity and can lead to further investigation and analyses. They are also useful to review as the pipe section is re-inspected and the charts compared against different times in the pipeline's operational life. Along with other analysis outputs, these charts can support investigation into CP adequacy, the reassessment interval planning process, the internal corrosion program and the excavation/repair program.

4.2.3.1 Metal Loss Orientation Charts

Metal loss depth severity is plotted as circumferential orientation versus axial location. The external corrosion feature distributions for the ML-CD, CD-HL and HL-NW segments of Line 9B are shown in Figures 4.1 – 4.3, while the internal corrosion feature distributions are shown in Figures 4.4 – 4.6. The metal loss severity, taken from the most recent ILI data, has been delineated by the use of different colours as identified in the chart legends.

Figure 4.1, below, shows the external corrosion distribution on the ML to CD segment of this pipeline. The reader will observe areas that appear to be "bands" of high-density corrosion between MP 2252 and Montreal Terminal (MP 2260). This is an effect of the scale of the chart, and does not indicate real-world corrosion density. All features shown as meeting Enbridge excavation criteria were excavated and repaired between 1993 and 2010.

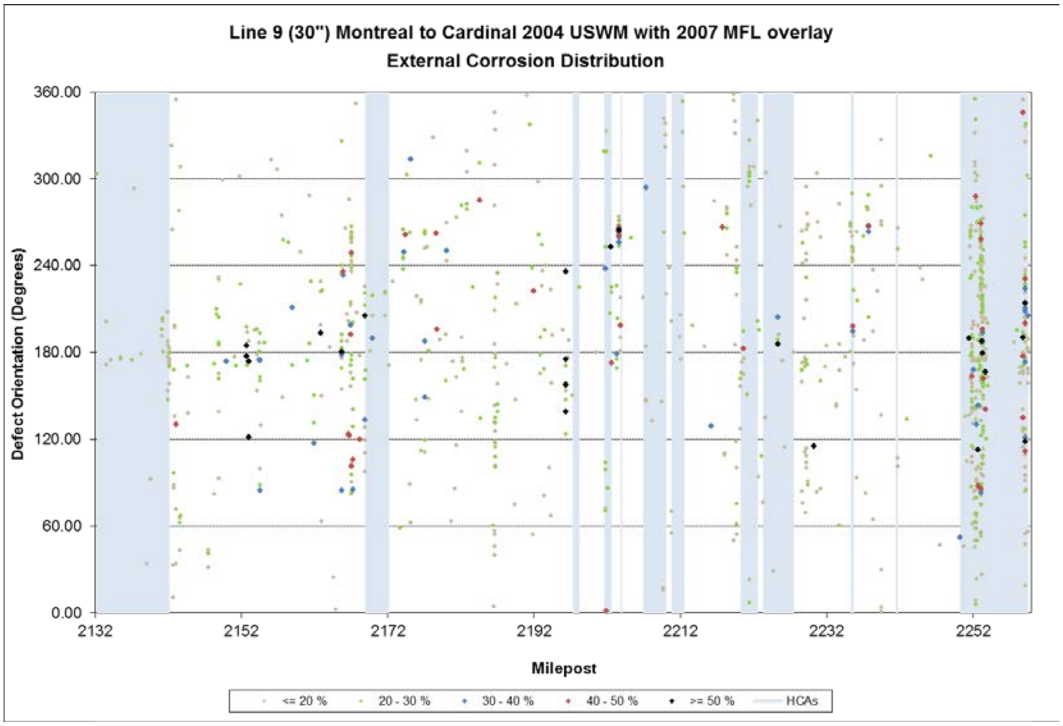


Figure 4.1 - Distribution of External Metal Loss (ML-CD)

Figure 4.2 shows the distribution of external metal loss on the CD to HL segment of this pipeline. As shown, no features in this segment met the Enbridge standard excavation criterion for depth of 50%.

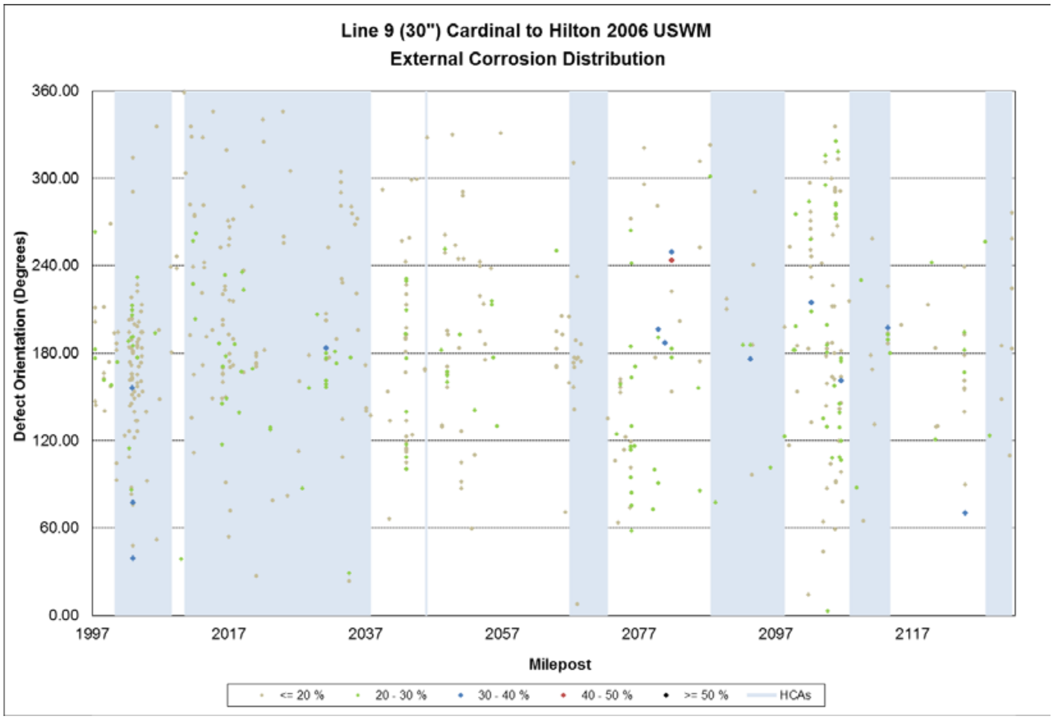


Figure 4.2 - Distribution of External Metal Loss (CD-HL)

Figure 4.3, below, shows the external corrosion distribution on the HL to NW segment of this pipeline. All features meeting Enbridge excavation criteria have been excavated and repaired.

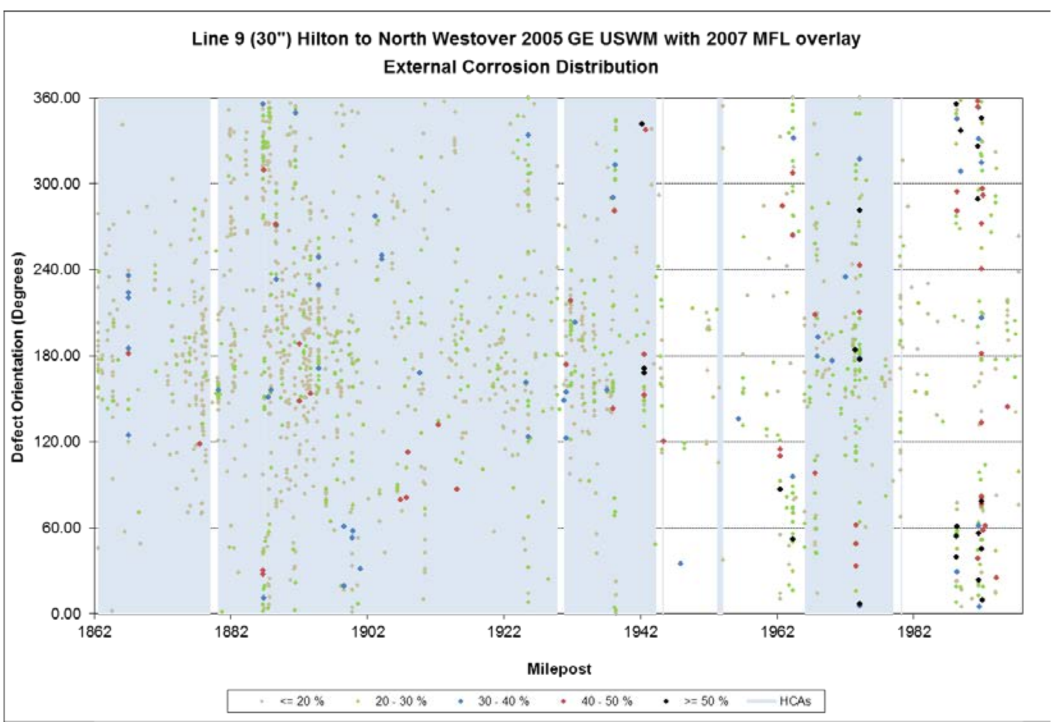


Figure 4.3 - Distribution of External Metal Loss (HL-NW)

Figures 4.4 – 4.6 show the distribution of internal corrosion on the ML to CD, DC to HL and HL to NW line segments. There is no pattern of corrosion occurring on the bottom of the pipe, indicating that the internal corrosion threat is being managed. All features meeting Enbridge excavation criteria have been excavated and repaired.

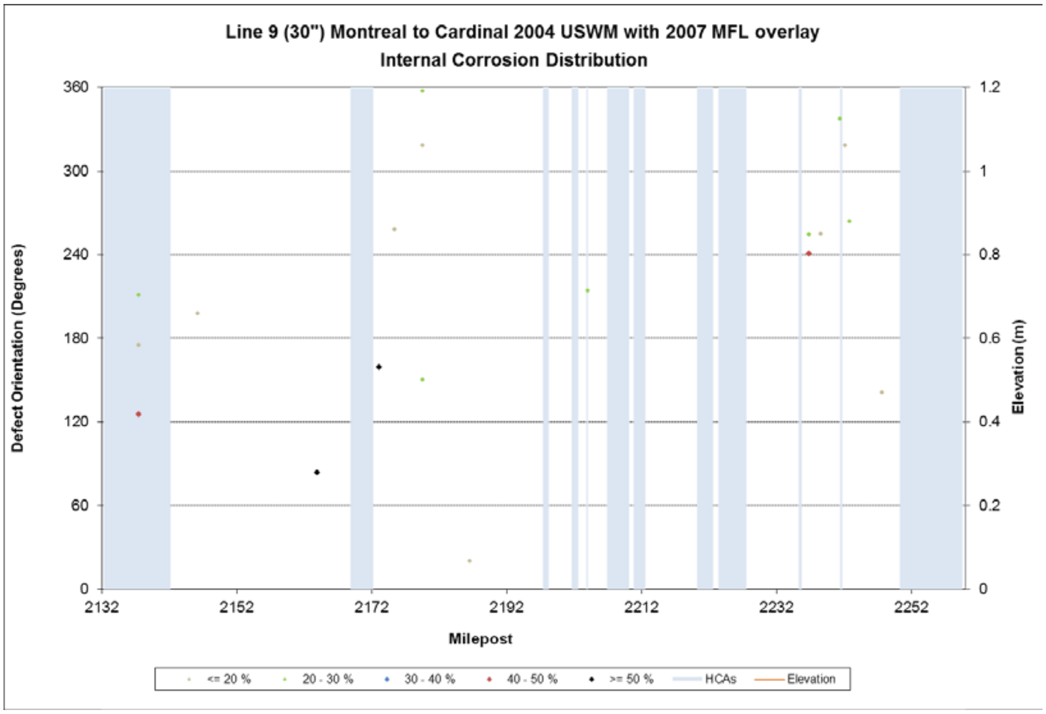
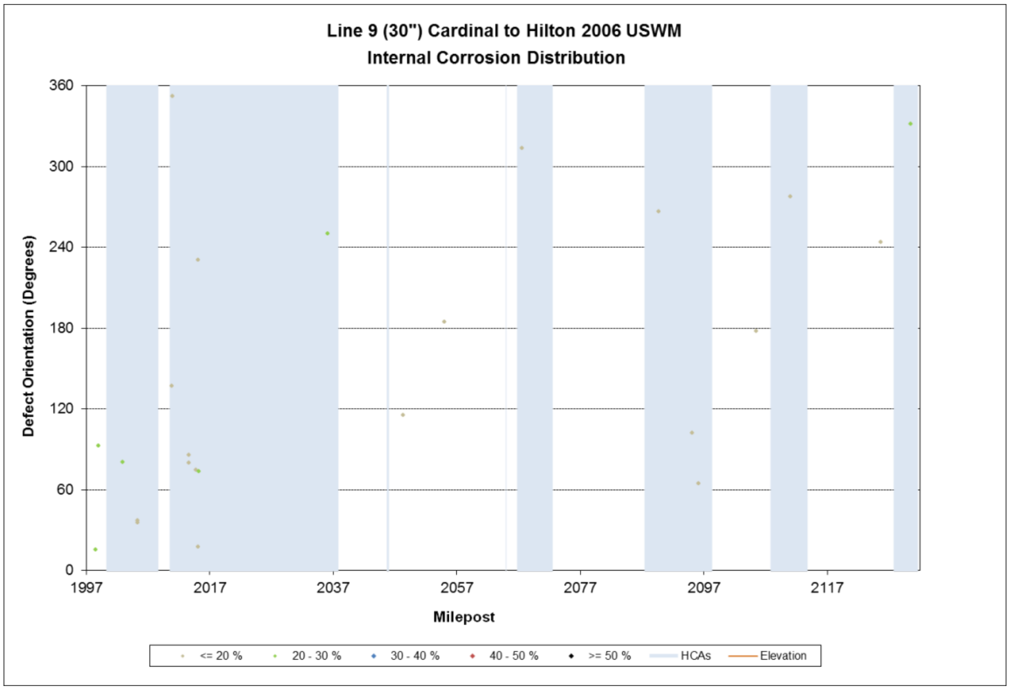
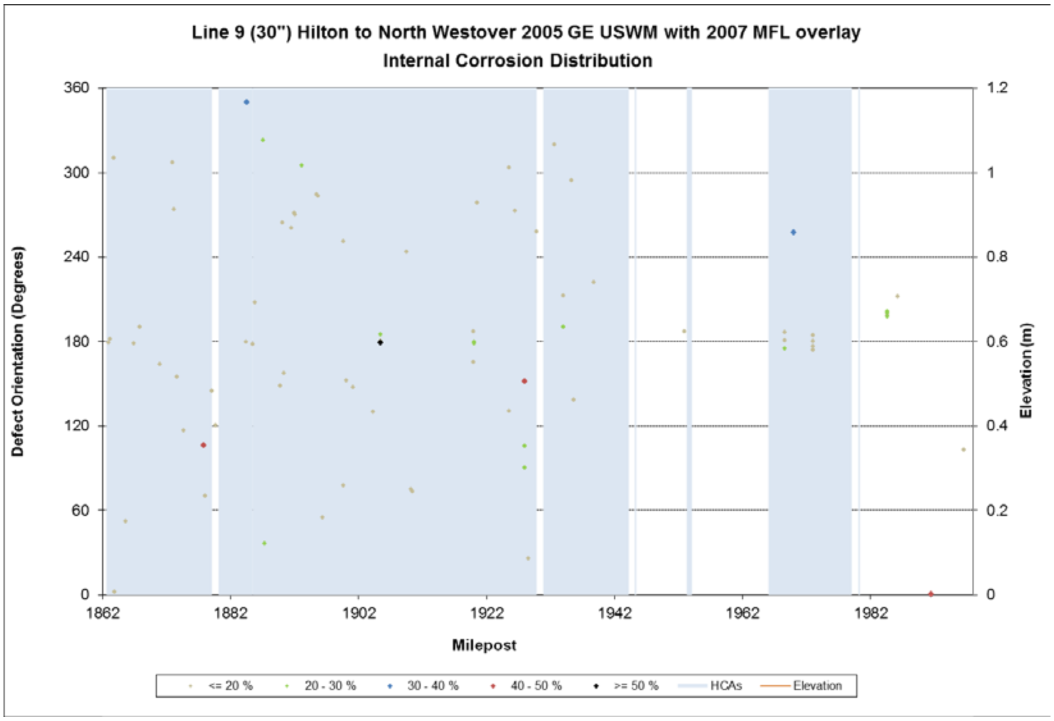


Figure 4.4 - Distribution of Internal Metal Loss (ML-CD)



1 **Figure 4.5 - Distribution of Internal Metal Loss (CD-HL)**



1 **Figure 4.6 - Distribution of Internal Metal Loss (HL-NW)**

2 According to Figures 4.1 – 4.6, there are 49 features on 35 joints that meet depth criteria for
3 excavation. All of these features have been excavated and repaired.

4.2.3.2 Metal Loss Histograms

Figure 4.7 shows the number of metal loss ILI anomalies grouped into depth ranges of 10%.

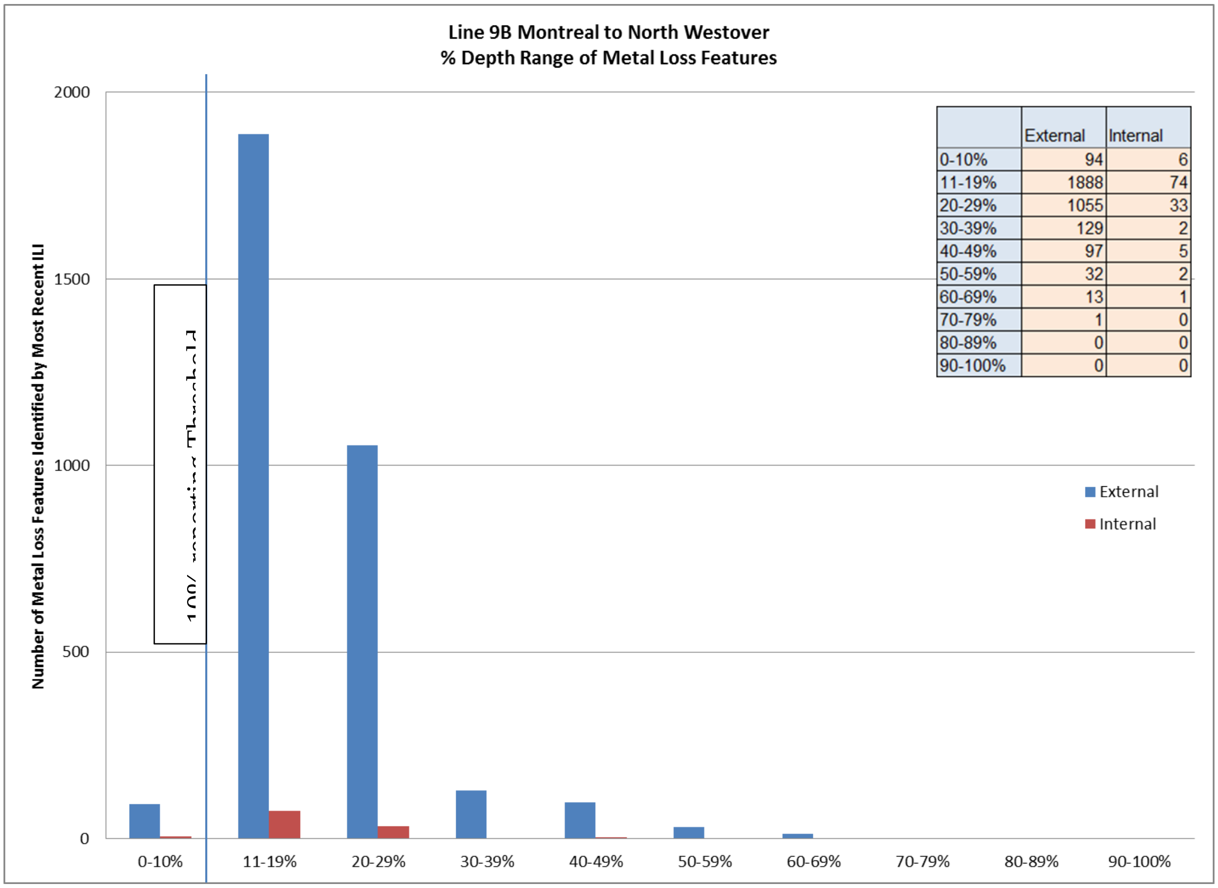


Figure 4.7 - Percent Depth Range of Metal Loss

Figures 4.1 through 4.7 show that the majority of the metal loss anomalies detected are at a shallow depth and therefore do not pose an immediate threat to the integrity of the pipeline. 35 joints were identified with features meeting Enbridge excavation criterion for depth of 50%, all of which have been excavated and repaired. Features below the 50% excavation criterion will be monitored on an ongoing basis as future ILI assessments become available.

4.2.3.3 Rupture Pressure Charts

Internal and external metal loss anomalies with ILI tool-reported RPR values have been plotted by milepost in Figures 4.8, 4.9 and 4.10. Features are excavated, assessed and repaired when their RPR falls to or below 1.0, or 100% of the Specified Minimum Yield Strength ("SMYS") of the pipe. As can be seen from the figures below, 11 features required excavation based on the 1.0-RPR criterion. All features shown as meeting Enbridge excavation criteria were excavated and repaired between 1993 and 2010.

Figure 4.8 shows the corrosion defect distribution based on RPR on the ML to CD segment of this pipeline. The reader will observe areas that appear to depict high-density corrosion between

MP 2252 and the Montreal Terminal at MP 2260. This is an effect of the scale of the chart, and does not indicate real-world corrosion density

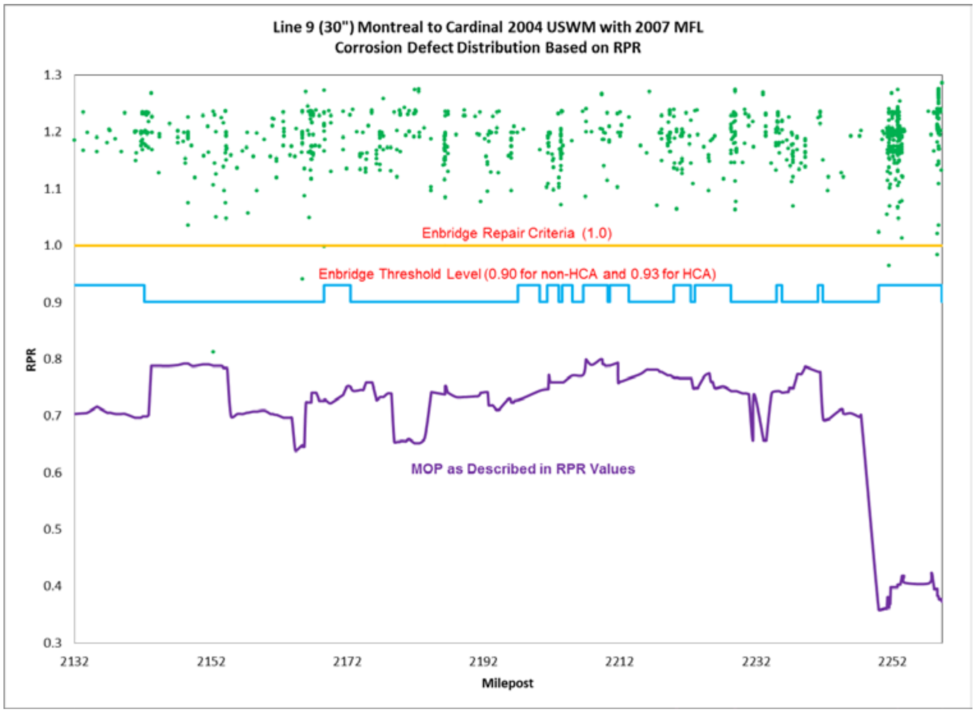


Figure 4.8 - Line 9 (ML – CD) – Predicted Metal Loss Failure Pressure

Figure 4.9 shows the corrosion defect distribution based on RPR on the CD-HL segment of this pipeline.

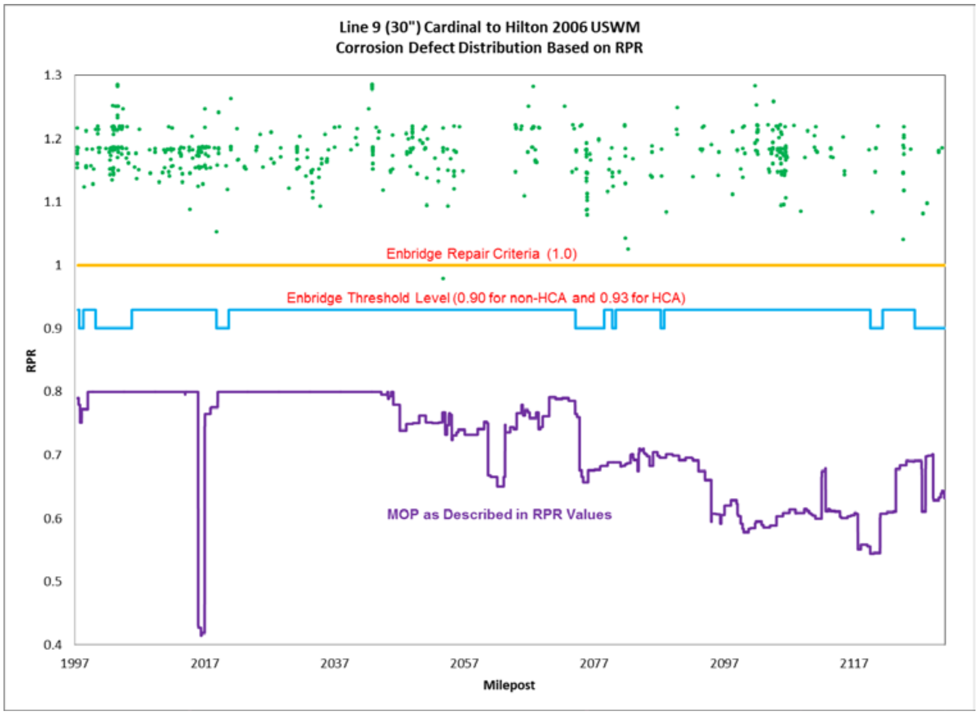


Figure 4.9 - Line 9 (CD – HL) – Predicted Metal Loss Failure Pressure

Figure 4.10 shows the corrosion defect distribution based on RPR for the HL-NW segment of this pipeline.

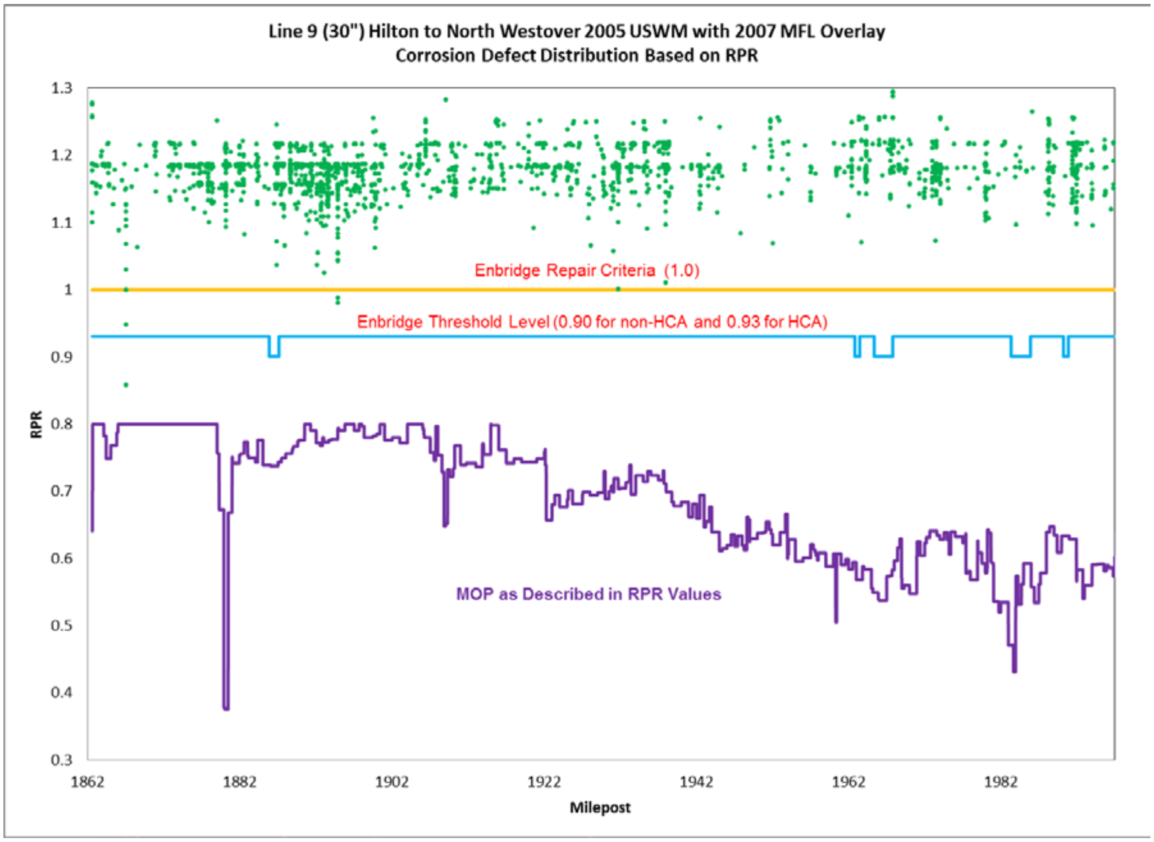


Figure 4.10 - Line 9 (HL – NW) – Predicted Metal Loss Failure Pressure

4.2.3.4 Metal Loss Depths

The depths of all internal and external metal loss anomalies identified by the most recent ILI runs are plotted in Figures 4.11, 4.12 and 4.13 along with the Enbridge standard excavation criteria and threshold level.

Figure 4.11 shows the corrosion defect distribution based on depth on the ML to CD segment of this pipeline. The areas between MP 2252 and Montreal Terminal (MP 2260) appear to depict high-density corrosion; however this is an effect of the scale of the chart, and does not indicate real-world corrosion density.

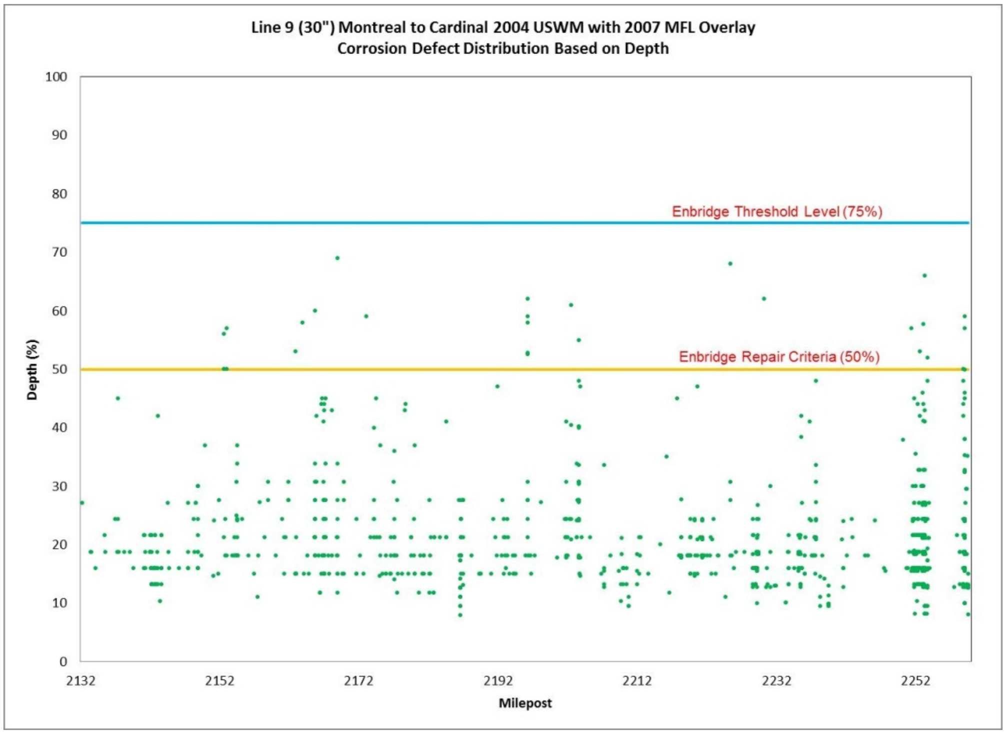


Figure 4.11 - Line 9 (ML – CD) – Metal Loss Depth Distribution

Figure 4.12 shows the corrosion defect distribution based on depth for the CD-HL segment of this pipeline.

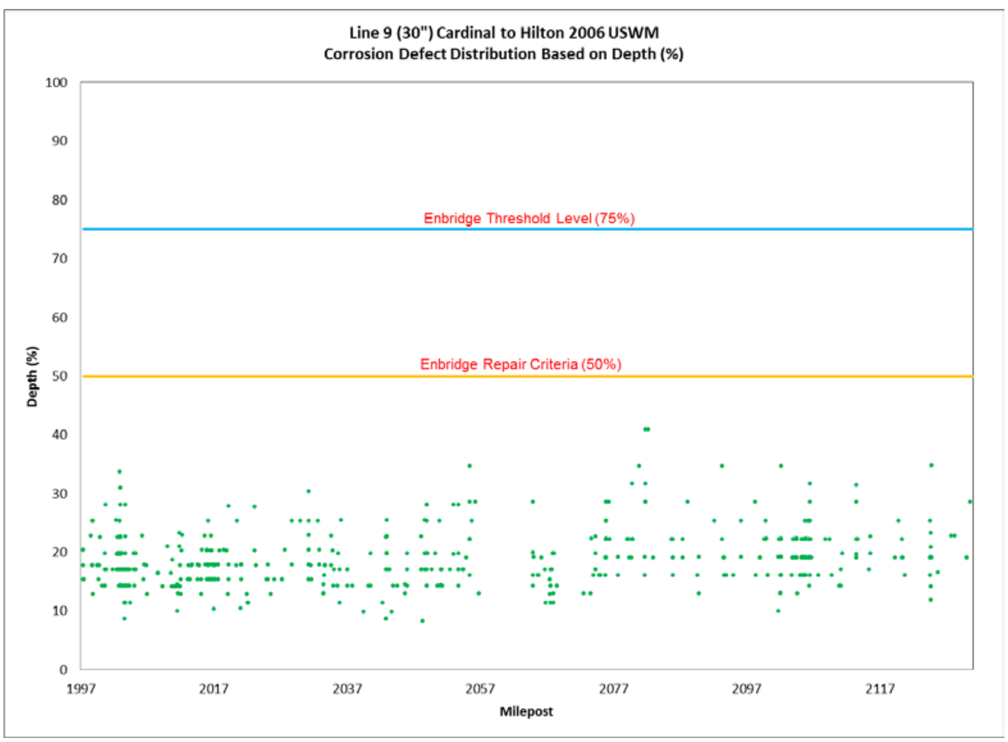


Figure 4.12 - Line 9 (CD – HL) – Metal Loss Depth Distribution

Figure 4.13 shows the corrosion defect distribution based on depth for the HL-NW segment of this pipeline.

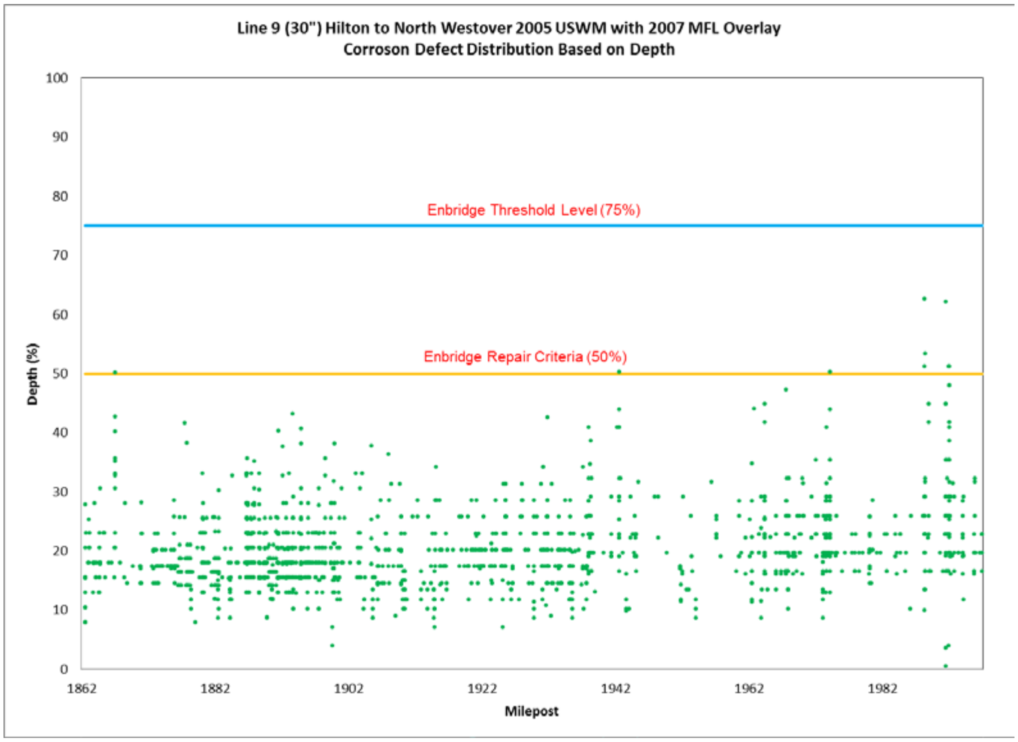


Figure 4.13 - Line 9 (HL – NW) – Metal Loss Depth Distribution

4.2.4 ILI Metrics

The metal loss metrics, including total number and per kilometre frequency, are summarized in Table 4-3 below. Table 4-3 shows the feature density per kilometre for both external and internal corrosion. The threat from internal and external metal loss is discussed in Sections 4.2.5 and 4.2.6 of this EA and is being monitored and managed as per the Corrosion Integrity Management Plan.

Table 4-3 - ILI Metrics

		Metal Loss RPR		Metal Loss Depth	
		1.0<RPR<1.1	**1.1<RPR<1.2**	**D<20%**	**20%<D<50%**
ML-CD External	# Features	21	431	626	320
	Feature Density (per km)	0.10	2.09	3.04	1.55
ML-CD Internal	# Features	1	7	8	9
	Feature Density (per km)	0.00	0.03	0.04	0.04
CD-HL External	# Features	18	140	402	167
	Feature Density (per km)	0.08	0.65	1.86	0.77
CD-HL Internal	# Features	0	5	18	6
	Feature Density (per km)	0.00	0.02	0.08	0.03
HL-NW External	# Features	41	1311	1007	737
	Feature Density (per km)	0.19	6.04	4.64	3.40
HL-NW Internal	# Features	0	57	53	21
	Feature Density (per km)	0.00	0.26	0.24	0.10

4.2.5 Corrosion Growth Rates

CGRs are calculated in order to provide insight into the integrity condition of the pipeline and to support monitoring and mitigation planning activities. As part of Enbridge's standard CGR analysis processes, locations found to be experiencing high CGRs are investigated by integrating supporting data such as CP investigations, other ILI data, satellite imagery and elevation data.

The historical CGRs shown in Table 4-4 have been calculated by dividing the defect depths by the calculated time of growth multiplied by a safety factor. Industry standards offer guidelines regarding maximum expected external CGRs. Table 4-4 below shows the average historical CGRs experienced on this pipeline from ML to NW as well as the historical 95th percentile CGRs.

Table 4-4 – Average and Historical 95th Percentile CGRs

Description		Average CGR	Historical 95th Percentile CGR
ML-CD Historical CGRs	External	0.044 mm/yr.	0.15 mm/yr.
	Internal	0.082 mm/yr.	0.17 mm/yr.
CD-HL Historical CGRs	External	0.076 mm/yr.	0.11 mm/yr.
	Internal	0.061 mm/yr.	0.09 mm/yr.
HL-NW Historical CGRs	External	0.090 mm/yr.	0.15 mm/yr.
	Internal	0.065 mm/yr.	0.11 mm/yr.

Table 4-5 contains a summary of CGRs found in industry guidelines and/or standards, as compared to 95th percentile rates measured on Line 9B shown in Table 4-4. The industry guideline rates are higher than the 95th percentile rates for external corrosion seen on this pipeline, which indicates that the CGRs present on Line 9 are low compared to industry experience.

Table 4-5 - Industry Guidelines for External CGRs

Standard/Guideline	Recommendations
NACE RP0102 (Ext)	0.3 mm/yr.: 80% confidence max rate with "good" CP
ASME B31.8S	0.31 mm/yr. max rate for active corrosion in low resistivity soils
GRI-00/0230 (Ext)	0.56 mm/yr. for pitting; 0.3 mm/yr. for general corrosion

The growth rates used for ILI re-assessment interval determination take all of the above values into account, balancing Enbridge experience with industry experience. Specific rates used in these analyses are included in the Deterministic Growth Analysis in Section 4.2.8.1.

4.2.6 Internal Corrosion Program

4.2.6.1 Overview

Enbridge transports crude oils that contain trace amounts of potential corrodents such as water, suspended solids and bacteria. Under certain operating conditions (such as low flow rates / low turbulence) this can lead to the development of local corrosive conditions if these materials are allowed to accumulate and persist over long periods of time.

Enbridge's internal corrosion program is designed to collect and integrate data relevant to the internal corrosion threat. Enbridge regularly conducts evaluations that include periodic testing to ensure that the S&W content does not exceed tariff quality limits as well as routine analysis of operating conditions to ensure corrosive conditions do not develop. Line 9 is also monitored for internal corrosion through regular ILI. For Enbridge pipelines considered to have an elevated susceptibility to internal corrosion, additional monitoring and prevention programs may be implemented. Additional monitoring programs include coupons, Electric Resistance Matrices or Field Signature Method – Inspection Tools. Additional preventative programs include regular cleaning and/or inhibition treatments.

4.2.6.2 Product Characteristics and Operating Temperature

The properties for light and heavy crudes described in Table 4-6 below have been used to analyse internal corrosion susceptibility and are expected to represent the expected commodities permitted by the tariff limitations for Line 9.

Table 4-6 - Baseline Product Properties

	Density (kg/m^3)	Viscosity (cSt)
Light	800	2
Medium	876	20
Heavy	904	100

4.2.6.3 Internal Corrosion Susceptibility Analysis

A key component of the Enbridge Internal Corrosion Control Program is the regular analysis of Internal Pipe Corrosion ("IPC") susceptibility. These analyses are completed for all pipelines in the Enbridge system and are regularly updated as operating conditions change and new data (such as ILI data) becomes available.

This analysis uses several leading and lagging indicators to evaluate the potential internal corrosion threat based on Enbridge historical experience. Key factors include the monitoring of the product shipped; roughness of the pipeline's interior surface as reported through inspection data, which affects the accumulation of corrosive sediments; and the pipeline flow conditions, which determine the ability of pipeline product flow to flush corrodents out of the system. These factors are assessed and related to determine the IPC threat on all Enbridge pipelines.

4.2.6.4 Year 2012 Flow Rates

The proposed annual rate in reversed service is 47,696 m^3/day (300,000 bpd) in continuous operation. A range of line rates from 60% to 100% of this maximum has been used for the flow analysis.

As shown in Figures 4.14 and 4.15, the proposed flow rates are not expected to achieve the critical Froude number, the Froude value at which water can be fully entrained in the product. As such, a prevention program has been planned to displace corrodents on a regular basis through routine maintenance via in line cleaning tools.

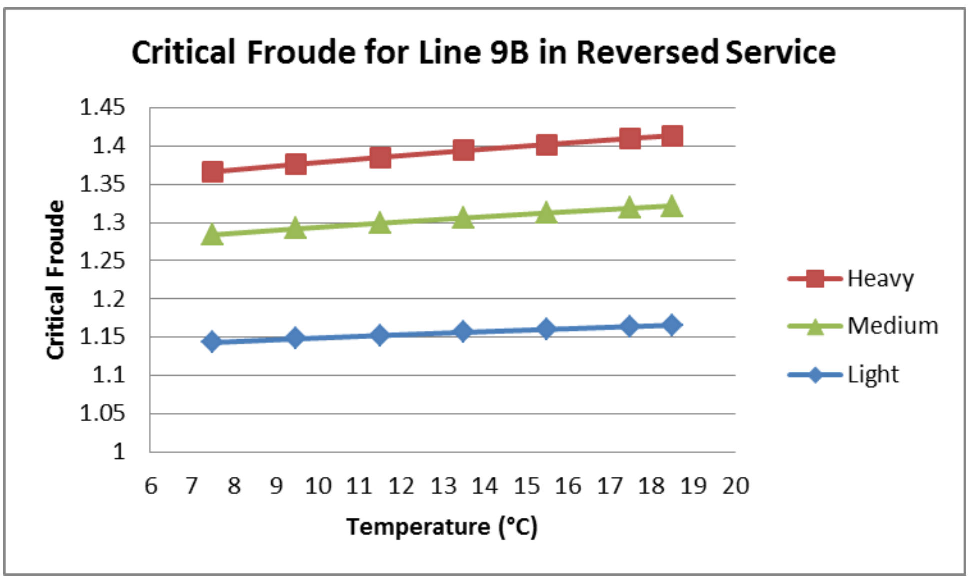


Figure 4.14 - Critical Froude by Temperature

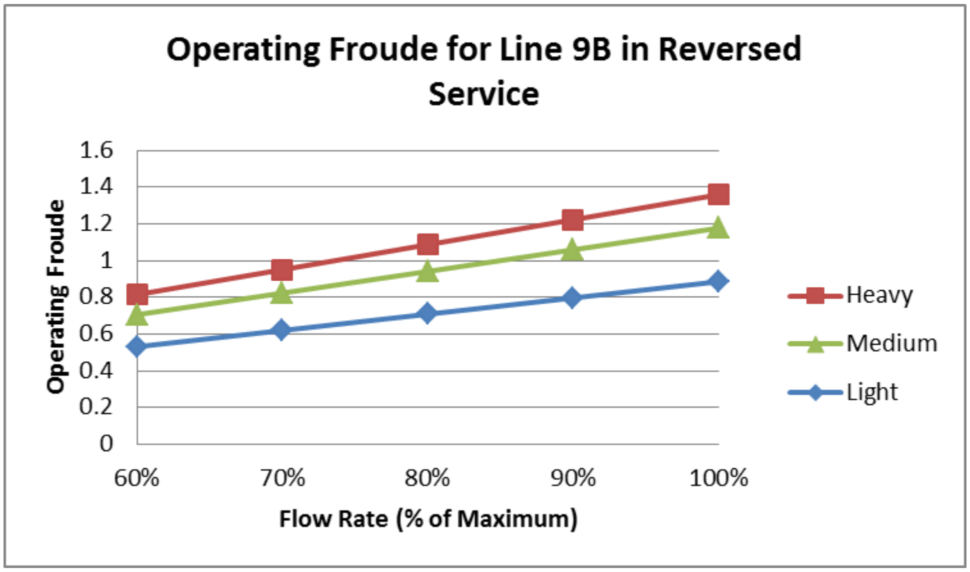


Figure 4.15 - Operating Froude by Flow Rate at 13°C

4.2.7 Metal ILI Data Accuracy

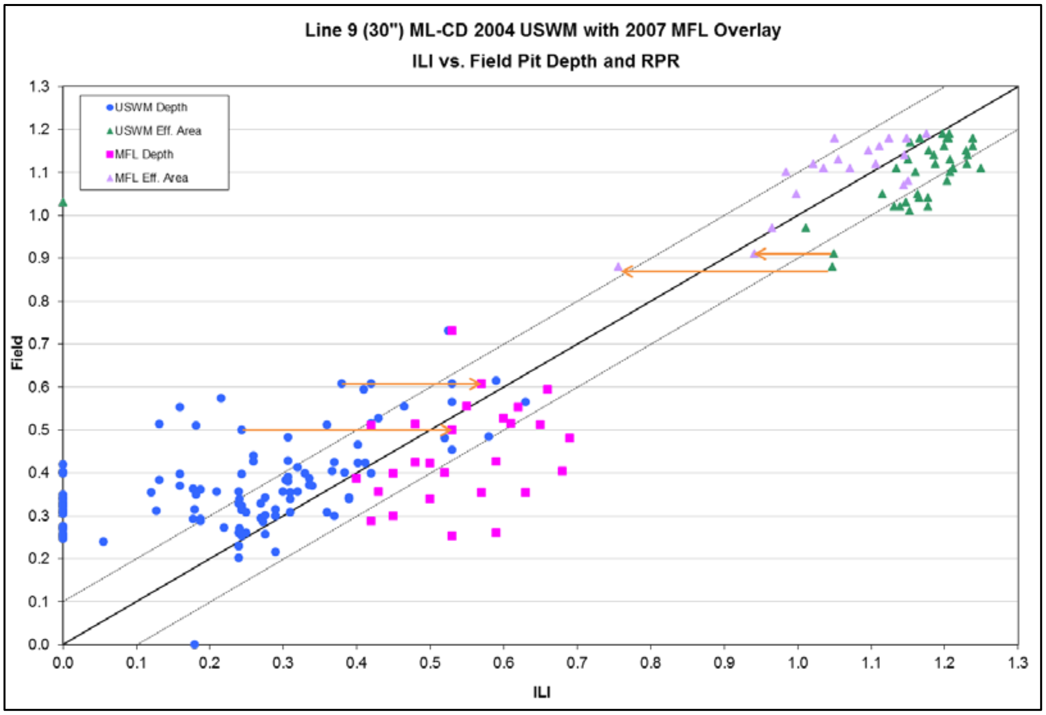
4.2.7.1 ILI Tool Accuracy Specification

The most recent metal loss inspections on this pipeline were conducted using high resolution technology provided by General Electric (“GE”) and BJ Pipeline Services, as shown in Table 4-1. The uncertainty and variability in tool accuracy is concentrated at the ILI tool reporting thresholds, and accuracy variability is anticipated for low level and/or non-critical features. The Probability of Detection (“POD”) increases with increasing feature severity, and therefore there is a low likelihood of the ILI tool missing a near-critical defect.

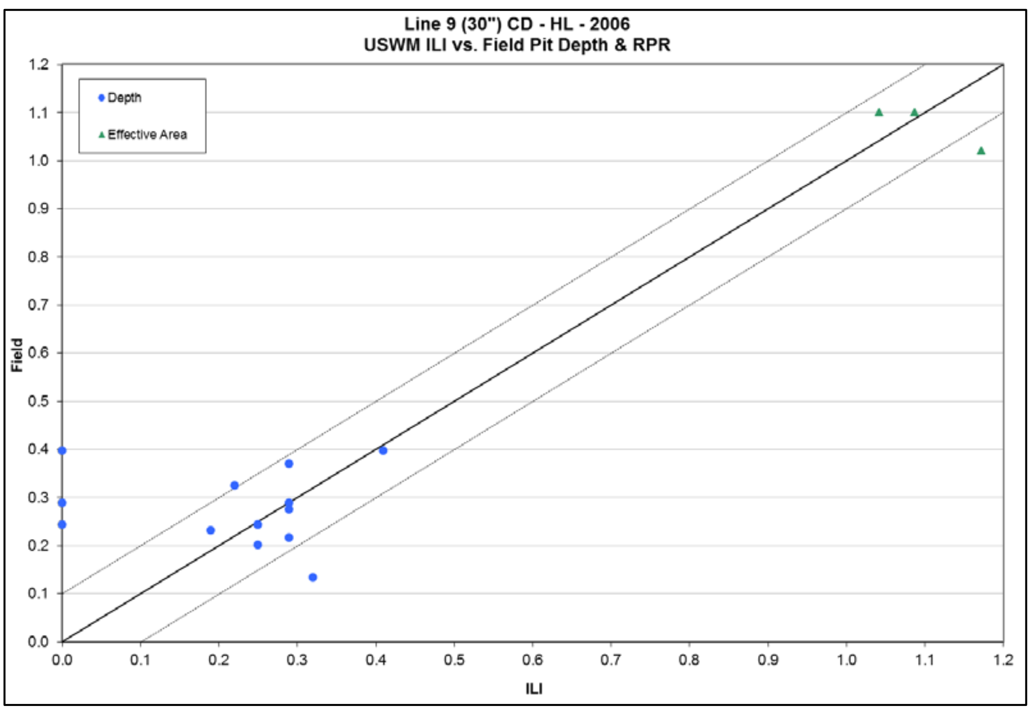
4.2.7.2 Metal ILI Data / Field Data Verification

The dig and repair programs have been completed based on the pre-2012 metal loss inspections. The data and field verification results from the 2012 ILI program will be assessed and incorporated into future unity plots.

The inspection programs incorporated results from two different inspection technologies: Ultrasonic (“UT”) and MFL. The MFL inspections were performed to augment the UT inspection technologies’ ability to detect small diameter corrosion pits. For the ML-CD and HL-NW inspections, where both the UT and MFL inspections were performed by GE, the vendor reported on deep pitting (>40% through wall). The limitation of the UT technology to see small diameter corrosion pits is visible by the number of false negatives on the Y-axes of the unity plots. The advantage of incorporating MFL data is clearly shown in Figures 4.16 – 4.20, where the MFL tool showed much better characterization of some small pits that were USWM outliers. For examples, please refer to the yellow arrows on Figures 4.16 and 4.18 which correlate the USWM and MFL data points.



1 **Figure 4.16 - ML-CD Unity Plot**



2 **Figure 4.17 - CD-HL USWM Unity Plot**

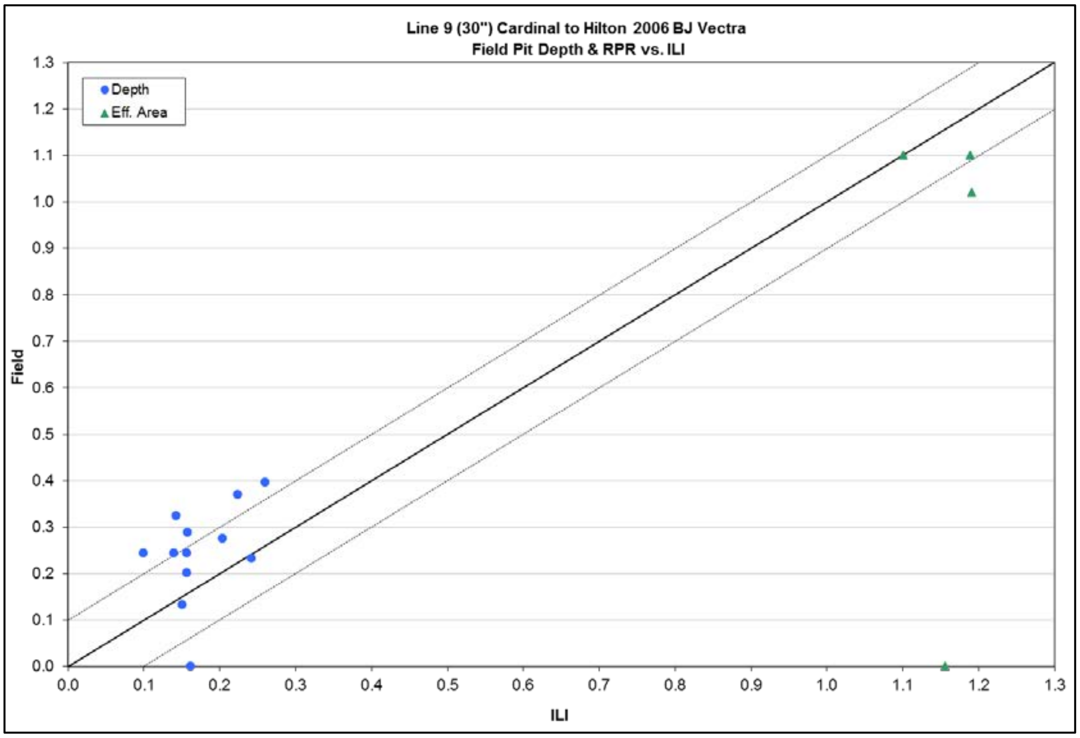


Figure 4.18 - CD-HL Vectra MFL Unity Plot

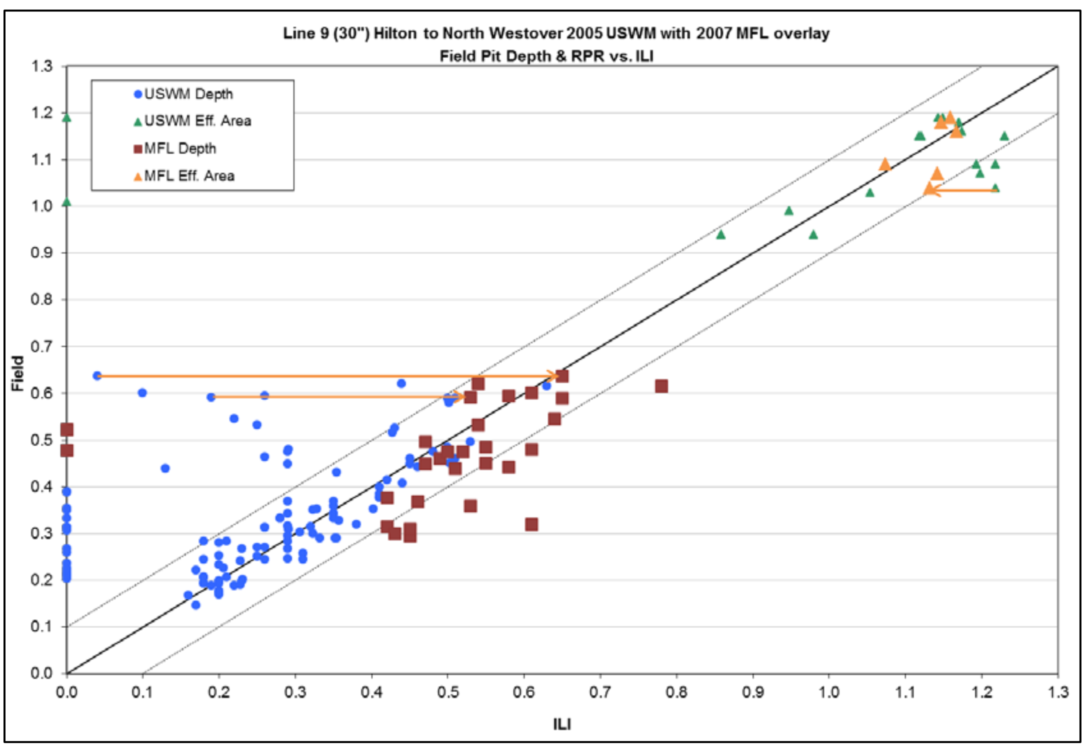


Figure 4.19 - HL-NW Unity Plot

4.2.8 Re-Assessment Interval Planning Experience

4.2.8.1 Defect Severity Threshold Level for Reassessment

To incorporate a safety margin within the metal loss monitoring programs, Enbridge has set the re-assessment intervals for this line such that corrosion features are identified for repair before they grow past a “threshold level” equivalent to a RPR of 0.9 and a depth of 75%. The RPR is defined as the predicted failure pressure of an anomaly divided by the pressure necessary to achieve stress in the pipe wall equivalent to 100% of the pipe’s SMYS. Briefly stated, an RPR value of 1.0 equates to 100% of SMYS.

4.2.8.2 Deterministic Growth Analysis

To provide additional insight into the corrosion condition of the pipeline, the anomaly population can be grown out over time utilizing appropriate CGRs.

Each metal loss anomaly is plotted relative to the Enbridge threshold level along a trap-to-trap section of the pipeline. The severity of each feature is increased by an offset value to address an ILI tool bias and accuracy variability determined through analysis of the ILI data to field data comparisons. The features are then grown out over time using a reasonably conservative corrosion growth rate. The year that a feature grows to a severity equivalent to the target severity level on the pipeline sets the reassessment interval up to a maximum of ten years.

For this pipeline, the depth threshold level is 75%, and the RPR threshold levels are 0.90 for non-High Consequence Area (“HCA”) locations and 0.93 for HCA locations. Conservative tool offsets and growth rates are applied to the analysis to account for tool variability.

Figures 4.20 through 4.25 demonstrate the growth of general corrosion features (i.e. RPR values) and the depth of metal loss features over time based on the USWM ILI results. Note that the graphs depict predicted corrosion depths in the year the first feature in that segment reaches the threshold level.

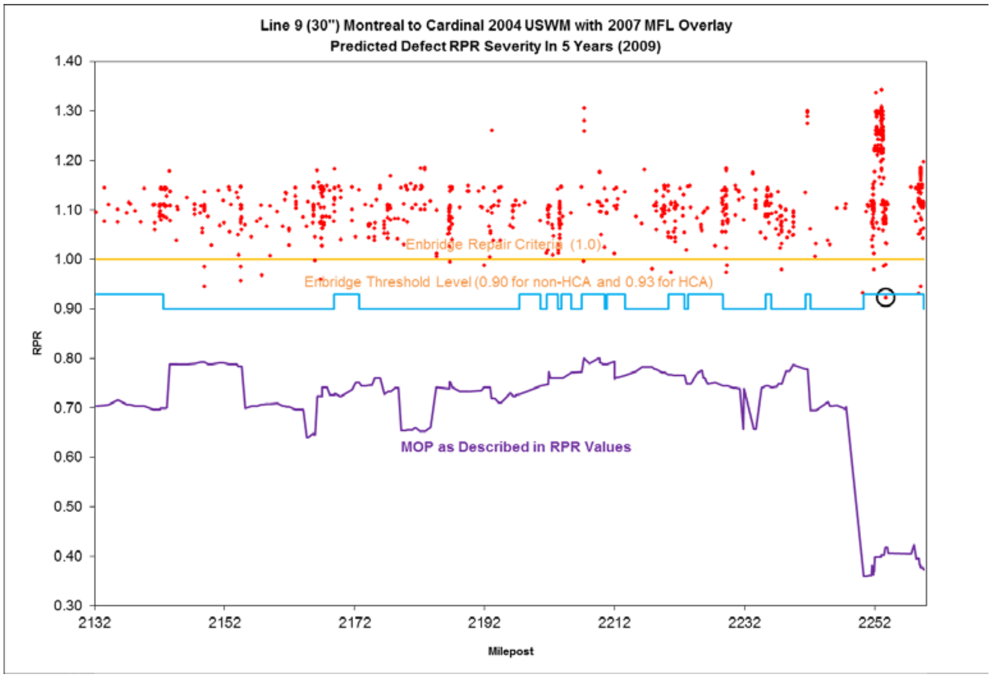


Figure 4.20 - Predicted RPR Severity in 2009 based on USWM and MFL

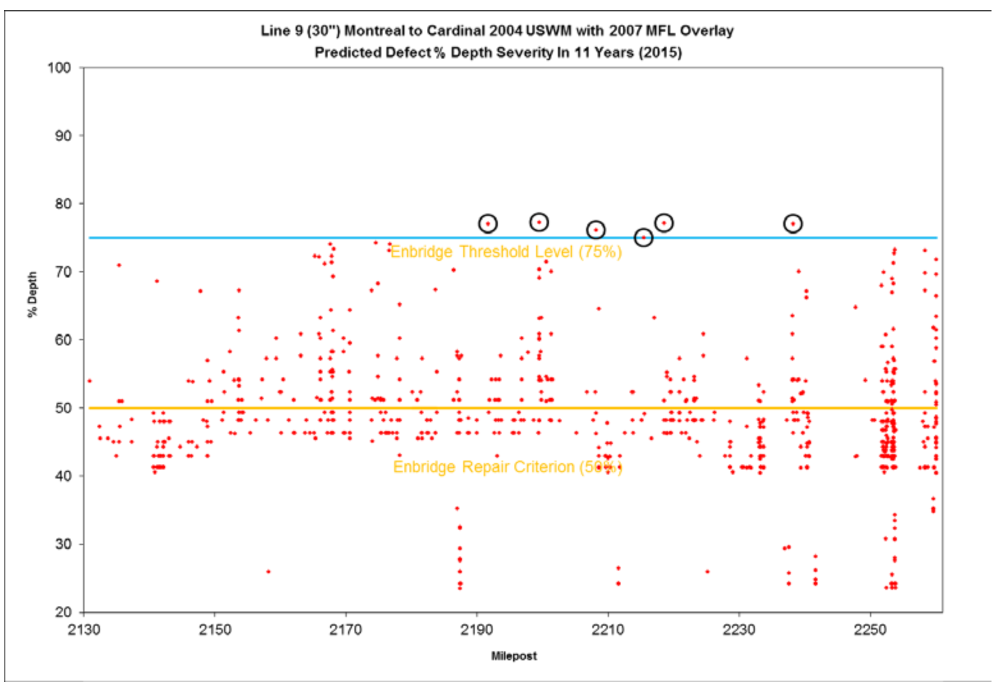


Figure 4.21 - Predicted Depth Severity in 2015 based on USWM and MFL

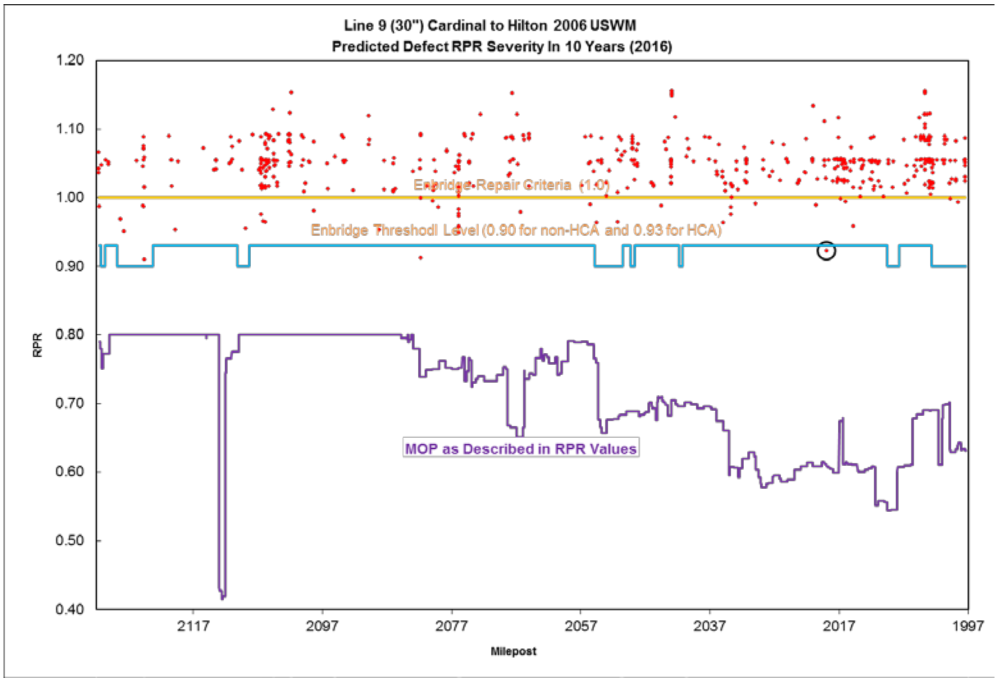


Figure 4.22 - Predicted RPR Severity in 2016 based on USWM

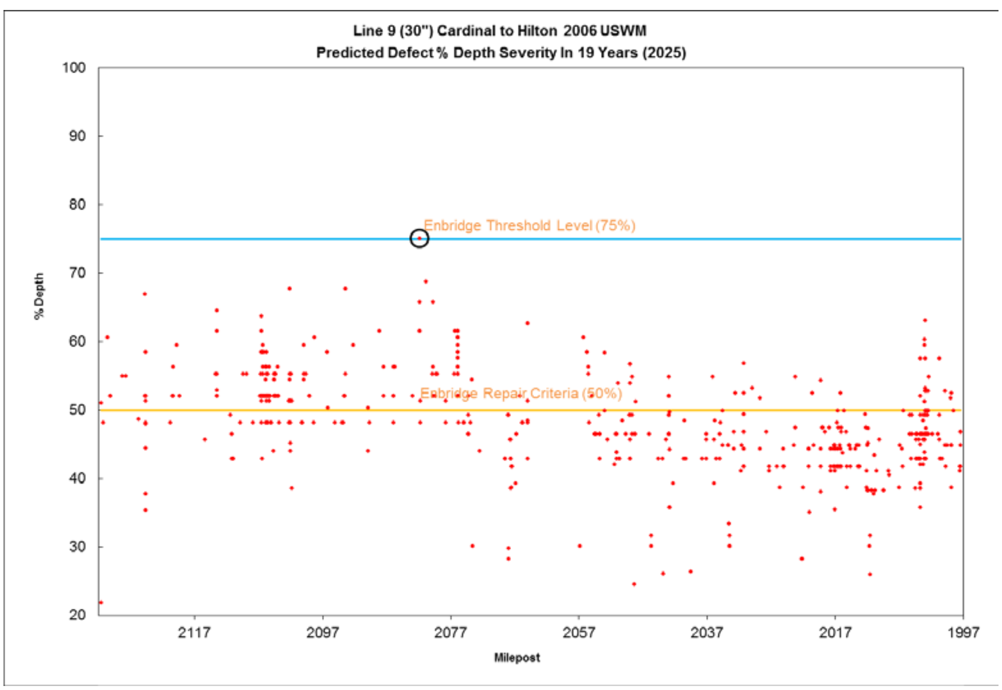
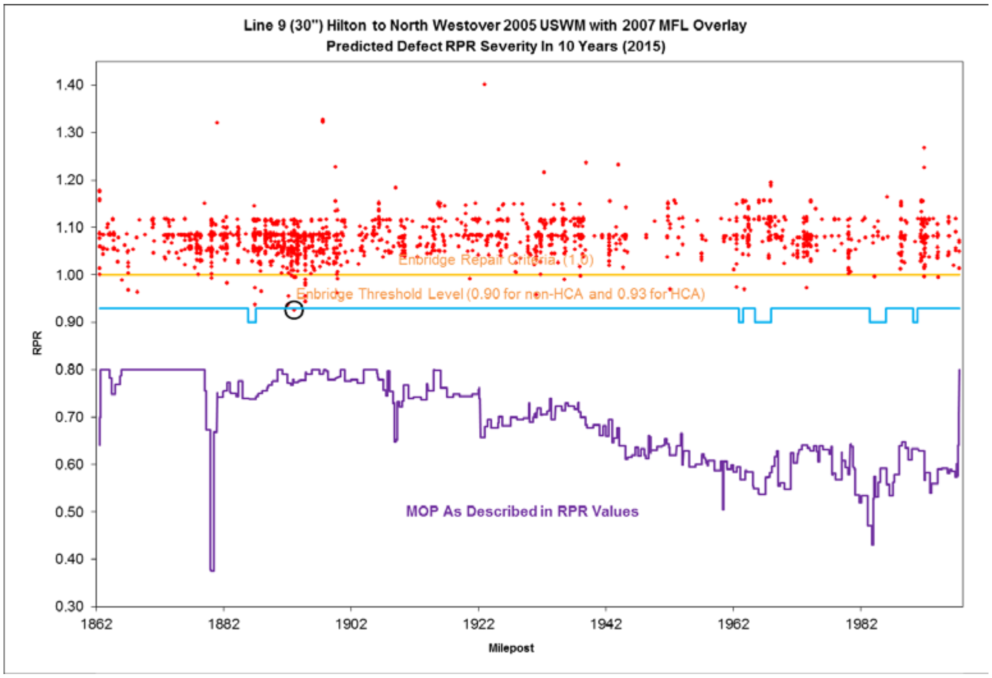
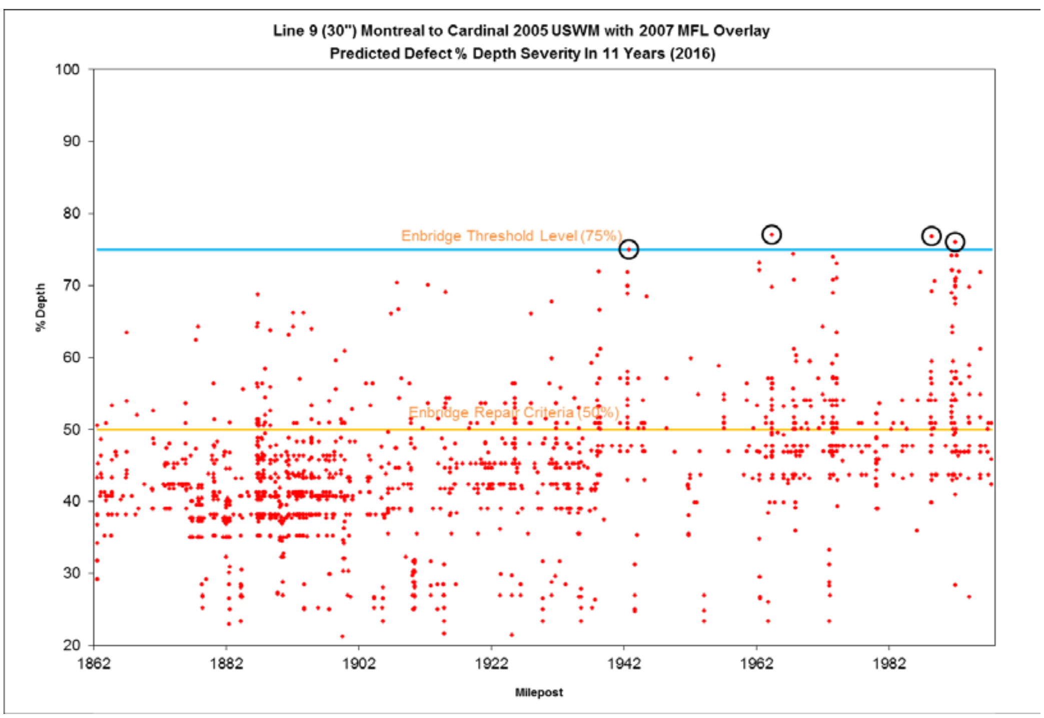


Figure 4.23 - Predicted Depth Severity in 2025 based on USWM



1 **Figure 4.24 - Predicted RPR Severity in 2015 based on USWM and MFL**



2 **Figure 4.25 - Predicted Depth Severity in 2016 based on USWM and MFL**

The deterministic analysis presents RPR and depth re-assessment intervals as shown in Table 4-7 below. These generally large re-assessment intervals illustrate that features on this pipeline segment are low in severity.

The re-assessment intervals in Table 4-7 are considered to be conservative due to the layers of safety built into the Deterministic Analysis process, including:

- feature severity is increased by an offset value to account for ILI bias;
- the CGR used is greater than the pipeline average; and
- the depth and RPR thresholds are well below failure levels.

Table 4-7 - RPR and Depth Re-Assessment Intervals

Segment	Predicted Defect RPR Severity	Predicted Defect % Depth Severity
ML-CD	5 years / re-inspection in 2009 (2012)*	11 years / re-inspection in 2015
CD-HL	10 years / re-inspection in 2016	19 years / re-inspection in 2025
HL-NW	10 years / re-inspection in 2015	11 years / re-inspection in 2016

*In order to ensure the safety of the pipeline past the expected inspections in 2012, operating pressure restrictions below the NEB-approved MOP have been self-imposed by Enbridge and excavation programs were implemented in 2011 and 2012.

4.2.9 Metal Loss Summary and Conclusions

Enbridge metal loss ILI and mitigation programs meet or exceed the current operating requirements. As a result, operating the pipeline system in reverse service, increasing the annual capacity of Line 9 and incorporating the transportation of heavy crudes will not affect the existing programs.

Based on the most recent ILI and dig programs, there are no metal loss features on Line 9B that require excavation or repair prior to the proposed flow reversal based on Enbridge's excavation criteria.

Proposed annual rates are not expected to achieve the critical Froude number at which free water will be entrained in the light or sour crude oils. As such, a prevention program has been planned to displace corrodents through routine maintenance via in-line cleaning tools.

Based upon the analyses completed and summarized in this document, the metal loss threat is being adequately addressed and should not prohibit the proposed flow reversal. The addition of heavy crude products and the increased capacity on Line 9 is not expected to have any adverse effects, and the correlating impact on pipeline integrity due to metal loss can be managed based on the current integrity management systems.

Metal loss ILIs have been completed for Line 9B in 2012 and are currently under analysis. Further line assessments will incorporate the newest ILI data.

4.3 Cracking

4.3.1 Crack Management Program

Enbridge has an established Crack Management Program to manage the threat associated with crack-related defects on its entire pipeline system.

The Crack Management Program for Line 9B consists of the following activities.

- Condition monitoring using a UT crack detection ILI tool.
- Engineering analysis to assess current FFS (i.e. immediately following the ILI).
- Excavation and repair programs to validate crack inspection data and mitigate critical anomalies. In addition to specific excavation programs based on the UT crack detection ILI tool, Enbridge also examines the pipe for crack-related features during its excavation programs based on other ILI technologies.
- Engineering analysis to assess continued FFS (i.e. takes into consideration subsequent growth from fatigue and/or environmental cracking).

Enbridge's excavation and repair programs associated with crack management are based in part on a safety factor approach where the reference level is the NEB-approved MOP as determined from the original commissioning hydrostatic test; there is no consideration for actual "at-site" operating pressures that lie below these NEB-approved MOP values. The current NEB-approved MOP values will not be altered by the proposed flow reversal or capacity increase and, thus, the excavation and repair programs will not require any modifications following the reversal. As there will be no increase in the normal discharge pressures associated with the pump stations, when the proposed flow reversal occurs, pending approval, all of the at-site pressure profiles will lie below the NEB-approved values as shown in Figure 4.26. For operational reasons, Line 9B has been operating at reduced pressures since September 2010; the magnitude of the current pressure reductions are 30% SMYS at Terrebonne, 36% SMYS at Cardinal and 46% SMYS at Hilton.

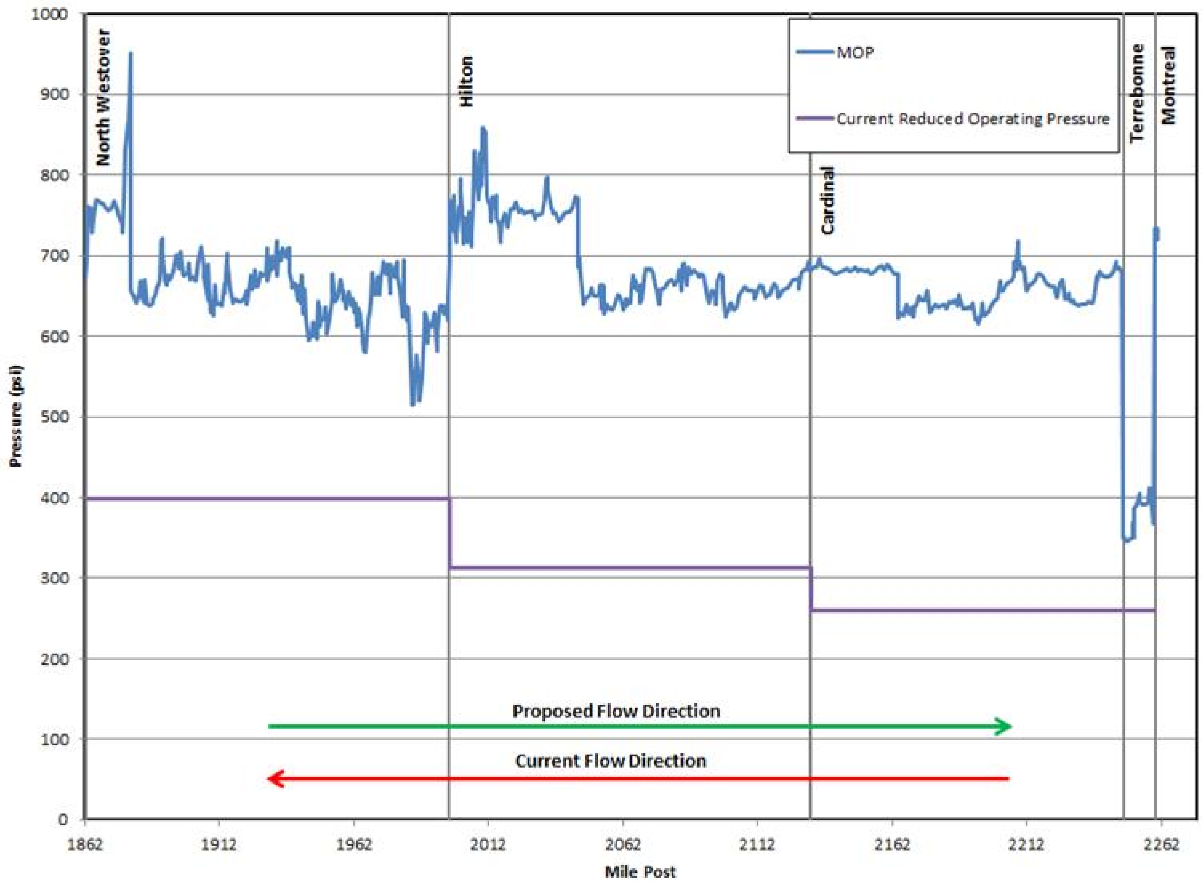


Figure 4.26 - NEB-Approved MAOP / Current Reduced Operating Pressure vs. Mile Post (NW-ML)

4.3.2 Assessment of Crack Detection In-Line Inspection Data

The portion of Line 9B between NW and ML was inspected by three different tool runs in three different years as listed below:

- **NW to HL:** inspected in 2005;
- **HL to CD:** inspected in 2006; and
- CD **to ML:** inspected in 2004.

All sections were inspected using the high resolution GE UltraScan™ Crack Detection tool (owned and operated by GE Oil & Gas, PII Pipeline Solutions) in order to identify any axially oriented crack-related features including those located in the longitudinal seam weld.

The ILI report from the GE UltraScan™ Crack Detection tool consists of a feature list that provides feature type, length, orientation, and depth for specific feature types. The feature types and a description of what they represent are provided in Table 4-8. In GE's final reports to Enbridge, for these three sections, GE indicated that there were no data quality related issues (i.e.

missing data, lack of sensor coverage, areas of speed excursions, etc.) associated with any of the inspection runs.

Table 4-8 - USCD Feature type nomenclature

USCD Feature Type	Typical Actual Feature (As confirmed through field investigations)
Crack-like ("CL")	Axial cracks or other discontinuities such as lack of fusion and impurities, typical of what is found in Flash Welded pipe.
Notch-like ("NL")	Reflectors due to seam weld edges or other shapes in the pipe wall that are creating UT response. Some potential of being a crack.
Crack-field ("CF")	Crack Fields are typically clusters of cracking such as SCC.
Metal loss	Shallow SCC or metal loss such as corrosion.
Dent	Geometrical discontinuity identified by sensor lift off. This process does not provide a reliable characterization of the dent shape or size.
Not Determinable ("ND")	This naming is provided when the vendor analyst is unable to classify the feature based on the vendor reference method.

The prevalence and severity of the features reported within the three segments of Line 9B are summarized in Table 4-9 and Figures 4.29 to 4.34.

Table 4-9 shows that there were a total of 4738 crack related features reported by the three tool runs within their corresponding final reports. In addition to these crack related features, there were also a total of 8223 metal loss features (approximately 63% of the total feature count) reported by the three tool runs. At the time of the time tool runs, GE did not have a sizing algorithm for these features and thus there were no lengths and depths provided by GE for these metal loss features.

Table 4-9 - Summary of Tool Reported Features

Feature Type	Relative Position	Radial Position	Number of Features	Percentage of Totals
Crack-Like	Base Metal	External	36	0.28%
		Internal	4	0.03%
	Adjacent to Weld	External	1184	9.14%
		Internal	34	0.26%
Crack Field	Base Metal	External	171	1.32%
		Internal	0	0.00%
	Adjacent to Weld	External	232	1.79%
		Internal	1	0.01%
Notch-Like	Base Metal	External	477	3.68%
		Internal	261	2.01%
	Adjacent to Weld	External	1988	15.34%
		Internal	350	2.70%
Metal Loss			8223	63.44%

Enbridge has excavated 569 of the reported metal loss features, of which 450 (approximately 80%) were subsequently found to be SCC in the field. The maximum field-measured depth of these SCC features was 1.85 mm (29% WT); the remaining life of this maximum-depth SCC feature is greater than 250 years. The remaining 20% of the excavated metal loss features were subsequently found to be another form of crack-related feature in the field. The maximum field measured depth of these other crack-related features was 1.8 mm (28% WT) with an estimated remaining life greater than 125 years. Thus, although there were no length and depth measurements provided by GE for the reported metal loss features, the field findings associated with such features indicate that they are not a threat to the integrity of the pipeline. Since these inspections, GE has made several improvements to its sizing and reporting algorithms, features with similar UT reflections as these metal losses are now either reported as CF (SCC) or CL indications.

Illustrated in Figure 4.27, approximately 72% of the reported features for which depth was provided had a reported depth of <12.5% of the pipe WT, while only one (0.02%) of the reported features had a reported depth >40% of the pipe WT. The feature with a saturated signal (i.e. >40% depth) was reported on the CD-HL segment of Line 9B and was found to be approximately 44% depth in the field in 2007.

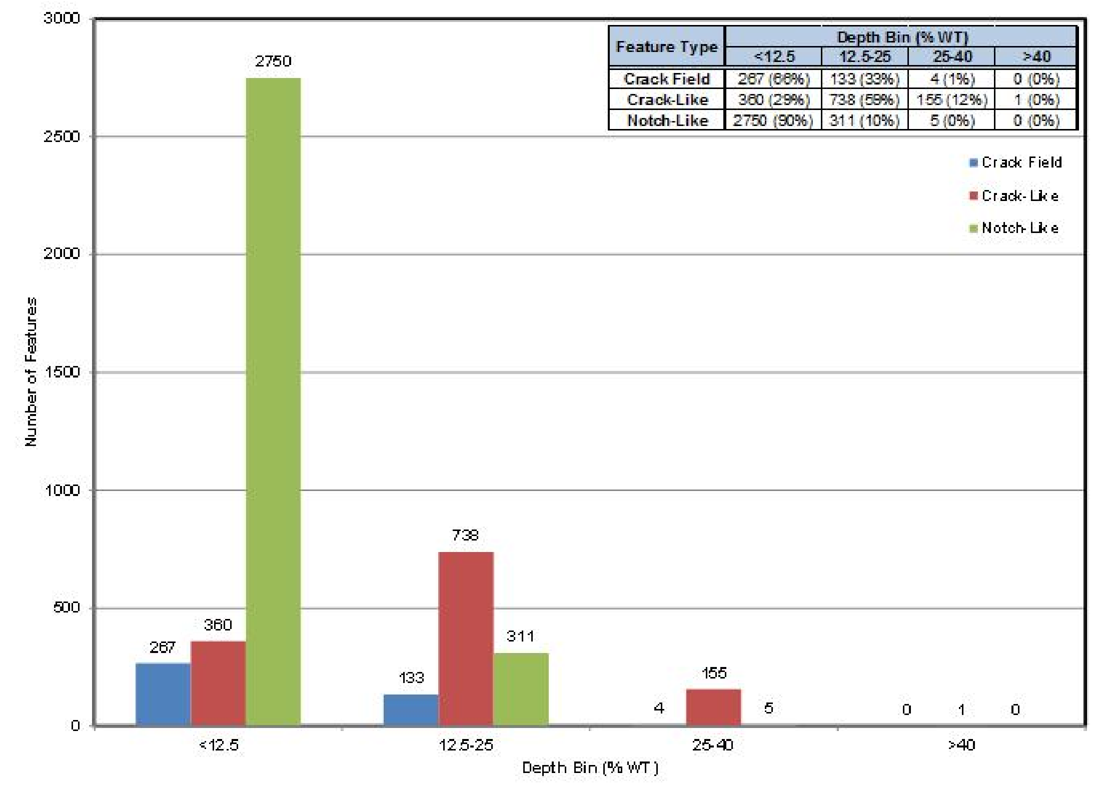
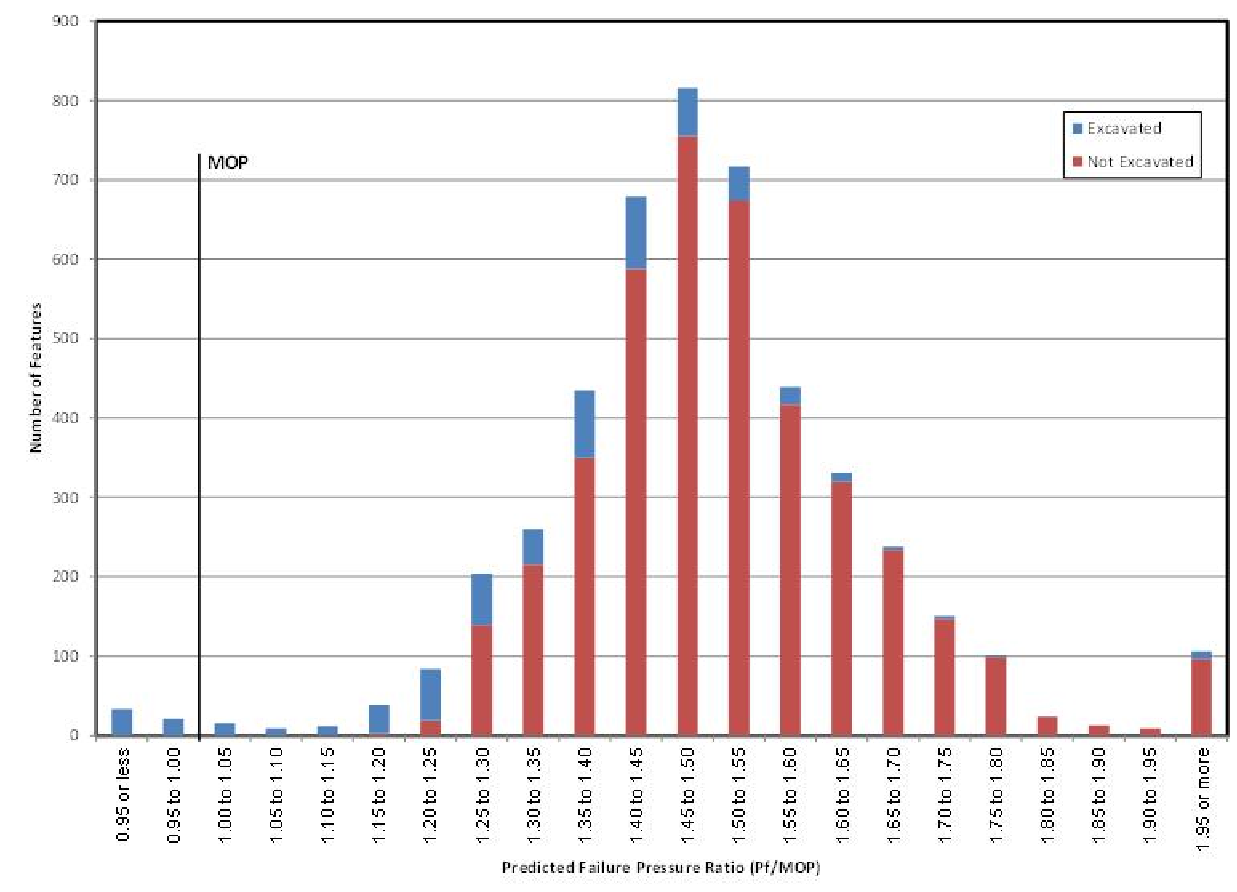


Figure 4.27 - Depth Distribution, All Reported Features (NW-ML)

Depicted in Figure 4.28, there are 184 features with Predicted Failure pressure ("Pf") less than MOP or 125% of MOP based on Enbridge's current integrity processes. The lowest calculated failure pressure is 86% of NEB-approved MOP or 212% of the current reduced operating pressure. Of the 172 features excavated to date, no feature was found in the field to actually have a predicted failure pressure less than MOP. The Lowest Pf/MOP value confirmed in the field is 1.12, whereas the Pf/MOP for the same feature based on ILI data was 1.24. The lowest factor of safety for features remaining on all three segments is 193% of the current reduced operating pressure.



Note: Assumed dimensions of the reported features used in the predicted failure pressure calculation are as follows: the total reported length of the feature and the upper bound depth of the given reported depth bin.

Figure 4.28 - Predicted Failure Pressure Ratio Distribution
All Reported Features (NW-ML)

As depicted in Figures 4.29 to 4.33, there are features reported throughout the length of Line 9B between NW and ML; however, there is a higher overall concentration in the section between HL and CD, as well as relatively higher concentrations in closer proximity to the current discharge side of the pump stations. Approximately 43% of digs completed on Line 9B were within the HL to CD section, and overall, approximately 83% of completed digs were within first 50 miles downstream of a discharge pump.

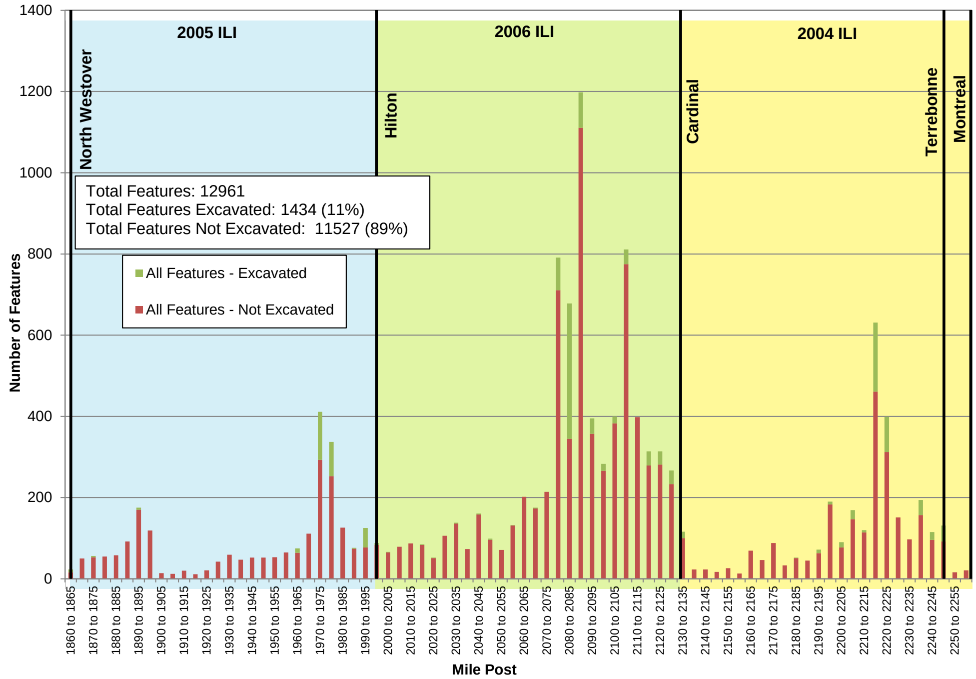


Figure 4.29- Number of All Reported Features vs. Chainage (NW-ML)

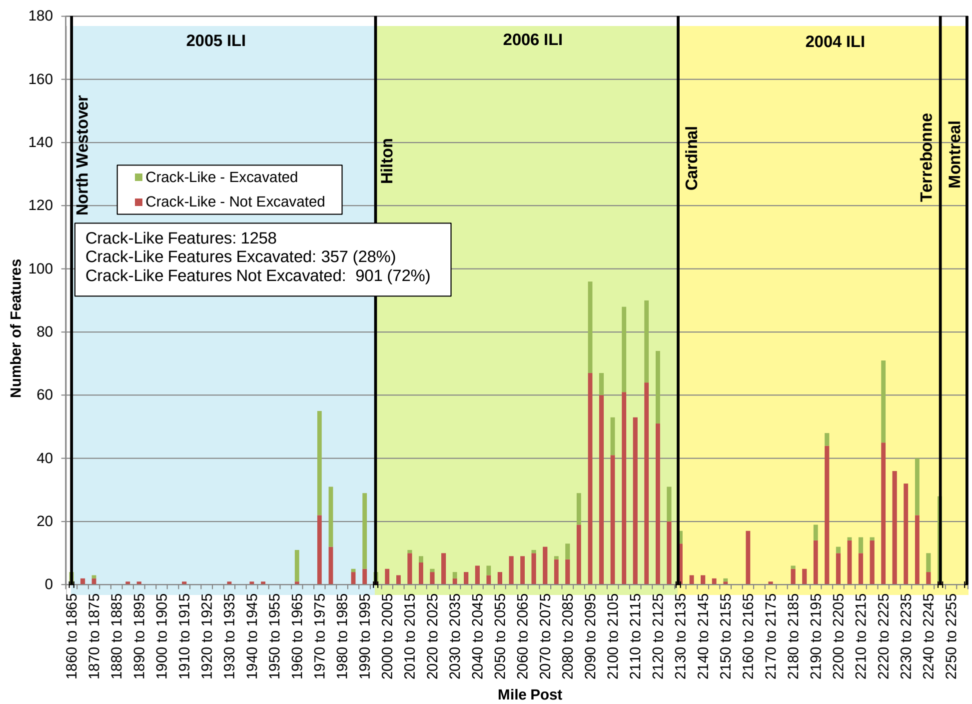


Figure 4.30 - Number of CL Features vs. Chainage (NW-ML)

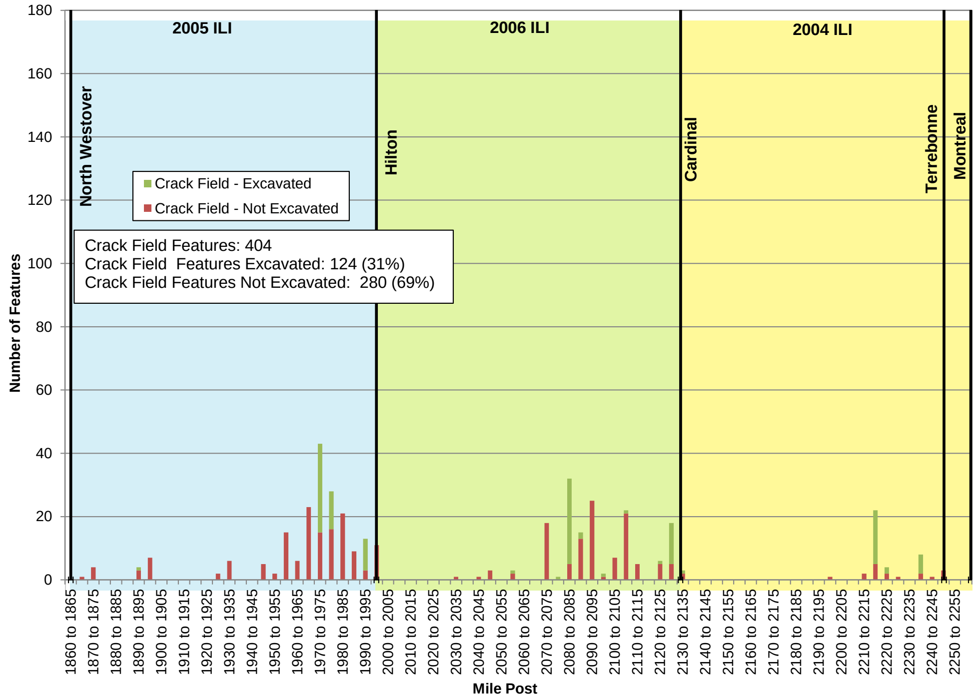


Figure 4.31 - Number of CF Features vs. Chainage (NW-ML)

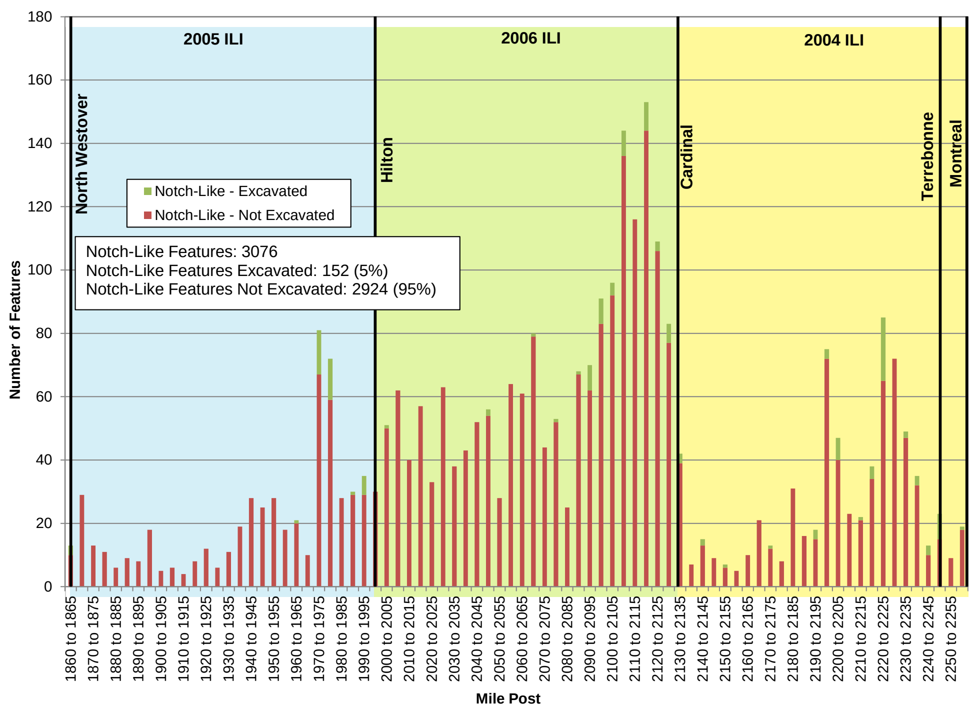


Figure 4.32 - Number of Notch-Like Features vs. Chainage (NW-ML)

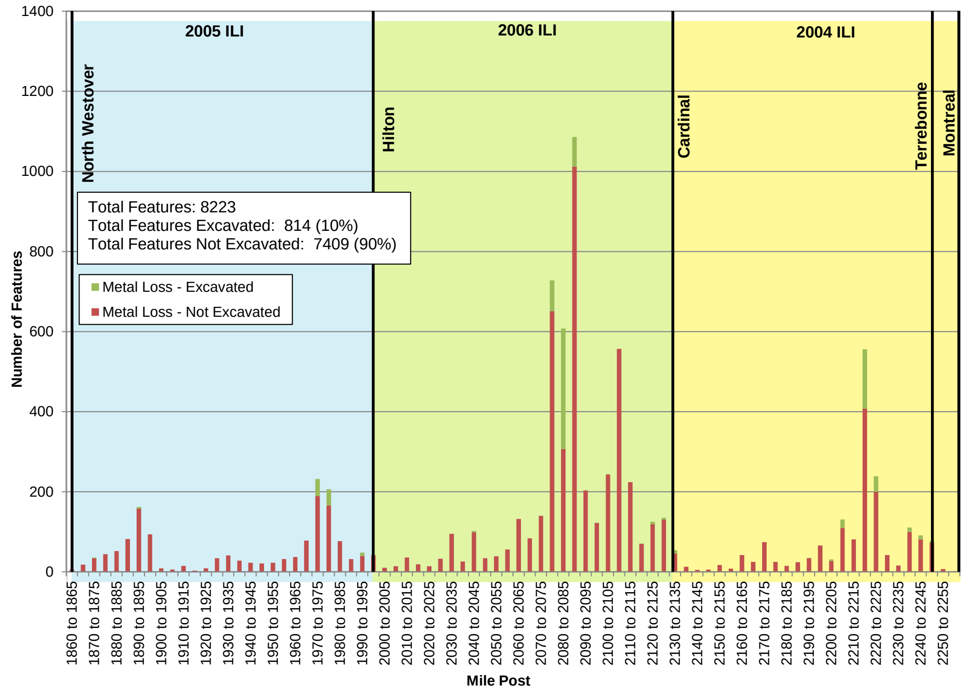


Figure 4.33 - Number of Metal Loss Features vs. Chainage (NW-ML)

4.3.3 Development of the Crack Excavation Program

Following the 2004 to 2006 crack detection inspections, Enbridge excavated and repaired all features with estimated failure pressure less than 125% of MOP. At that time, Enbridge employed the following assumptions in estimating failure pressure associated with each reported feature:

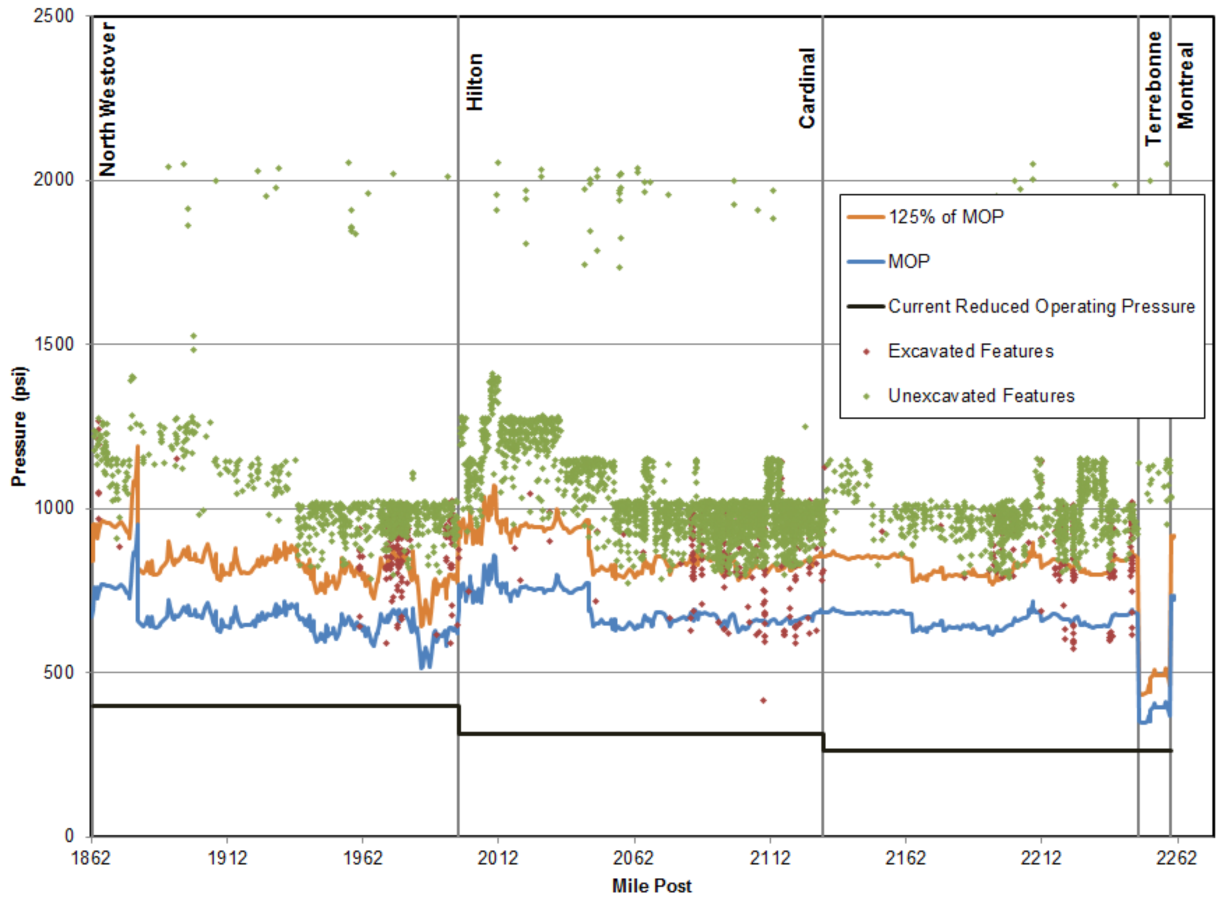
- Charpy V-notch impact toughness: 20 ft-Ib
- WT: WT reported by the GE UltraScan™ Crack Detection tool
- Feature Depth: upper limit of the reported depth bin or maximum profile depth (requested from GE) in some cases.

Since these tool runs and subsequent excavation programs, Enbridge has changed its acceptance criteria and the input assumptions used to assess a feature’s acceptability. The following assumptions are now used by Enbridge as input into the CorLAS™ software to calculate the predicted failure pressures of the reported features:

- Flaw profile: rectangular profile
- WT: the lesser of the nominal WT or the WT as measured by the UT wall measurement ILI tool
- Nominal yield strength for grade 359 MPa: 359 MPa
- Nominal tensile strength for grade 359 MPa: 455 MPa

- Flow strength: yield strength + 68.9 MPa
- Charpy V-notch impact toughness: 15 ft-lb
- Flaw Depth: Upper bound of the given reported depth bin
- Flaw Length: The total reported feature length

Based upon the above input assumptions, there were a total of 184 features on 149 joints that had a predicted failure pressure less than 125% of the MOP, shown in Figure 4.34. 172 of these 184 features have been subsequently excavated. The lowest predicted failure pressure of these reported features is 663 psi which equates to 86.3% of the NEB-approved MOP or 212% of the current reduced operating pressure. The vast majority of the features (82%) remaining in the pipeline have predicted failure pressures higher than 140% of the NEB-approved MOP. Enbridge is presently inspecting Line 9B between NW and ML, and these features will be re-evaluated based upon the new inspection data.



Note: Assumed dimensions of the reported features used in the predicted failure pressure calculation are as follows: the total reported length of the feature and the upper bound depth of the given reported depth bin.

Figure 4.34 - Predicted Failure Pressures, All Reported Features (NW-ML)

4.3.4 Statistical Evaluation of Dig Program

The overall selection of features for excavation has been assessed to assure that a sufficient quantity of each category is investigated. The target sample size is defined using a proportion-based calculation to determine the minimum number of features required to provide a minimum of 80% confidence that the selected features will represent the entire feature population.

Enbridge views 80% to represent a statistically relevant sample size. In determining the sample size, the bound on error (“B” in the formula below) is fixed at 10%, which is a typical value utilized for this type of assessment.

The proportion-based sample size calculations are based on the following relationship:

$$n = \frac{Np(1-p)}{(N-1)\frac{B^2}{z^2} + p(1-p)}$$

n = target sample size of digs

N = population of given feature type reported by ILI

p = proportion of a feature type within the entire feature population

B = bound on error

z = z value corresponding with a chosen confidence interval

Provided below is a summary of the confidence levels achieved to date.

- **ML to CD –** The current excavation program has achieved a statistical confidence of 99% for reported crack-like, CF and metal loss features. In addition, a statistical confidence of 90% has been achieved for reported notch-like features.
- **CD to HL –** The current excavation program has achieved a statistical confidence of 99% for reported CL, CF and metal loss features. In addition, a statistical confidence of 90% has been achieved for reported notch-like features.
- **HL to NW–** The current excavation program has achieved a statistical confidence of 99% for reported CL and CF. In addition, a statistical confidence of 85% and 90% has been achieved for reported notch-like and metal loss features respectively.

Thus the field-tool unity plots discussed in Section 4.3.7 are based on a statistically representative number of features.

4.3.5 Results of the Crack Excavation Program

The excavation program, based on the three crack tool runs, completed between NW and ML was performed between 2006 and 2009. Enbridge completed a total of 182 excavations involving 1042 reported features during the four-year excavation program. An additional 52 digs were issued between 2010 and 2011.

The major findings from the excavation program conducted in each of the three launcher and receiver sections are as follows.

ML to CD

There were 360 reported features excavated in this segment of which:

- 268 were found to be SCC. The most severe SCC colony found in the field had a predicted failure pressure of 783 psi, 145% of NEB-approved MOP, or 301% of the current reduced operating pressure; the corresponding tool predicted failure pressure for this SCC colony was 774 psi, 144% of NEB-approved MOP, or 297% of the current reduced operating pressure. The deepest SCC colony found in the field that corresponded to a reported feature had a depth of 1.6 mm (25% of WT); the corresponding tool reported depth for this SCC colony was 0.8 mm (12.5% of WT).
- 145 were found to be CL features, 56 of which were associated with SCC. The most severe CL indication found in the field had a predicted failure pressure of 687 psi, 129% of NEB-approved MOP, or 264% of the current reduced operating pressure; the corresponding tool predicted failure pressure for this indication was 649 psi, 121% of NEB-approved MOP, or 250% of the current reduced operating pressure. This feature was also the deepest feature found in the field, reported with a depth of 25-40% and found in the field to be 35% deep.
- There were 43 unreported features found in the field with length and depth dimensions larger than that of the tool reporting threshold and were thus classified as false negative features. A discussion of false negative features is provided in Section 4.3.5.1 below.

CD to HL

There were 492 reported features excavated in this segment of which:

- 304 were found to be SCC. The most severe SCC colony found in the field had a predicted failure pressure of 818 psi, 120% of NEB-approved MOP or 262% of the current reduced operating pressure; the corresponding tool predicted failure pressure for this SCC colony was 927 psi, 136% of NEB-approved MOP, or 297% of the current reduced operating pressure. The deepest SCC colony found in the field that corresponded to a reported feature had a depth of 2 mm (31% of WT); the corresponding tool reported depth for this SCC colony was 12.5-25%of WT.
- 149 were found to be CL features, of which three were associated with SCC. The most severe CL indication found in the field had a predicted failure pressure of 745 psi, 113% of the NEB-approved MOP, or 239% of the current reduced operating pressure; the corresponding tool predicted failure pressure for this indication was 742.5 psi, 113% of the NEB-approved MOP, or 238% of the current reduced operating pressure. This feature was found to be approximately 43% deep in the field and reported to be >40% by the ILI tool.
- There were 113 unreported features found in the field with length and depth dimensions larger than that of the tool reporting threshold and were thus classified as false negative features. A discussion of false negative features is provided in Section 4.3.5.1 below.

HL to NW

There were 190 reported features excavated in this segment of which:

- 99 were found to be SCC. The most severe SCC colony found in the field had a predicted failure pressure of 786 psi, 118% of NEB-approved MOP, or 197% of the current reduced operating pressure; the corresponding tool predicted failure pressure for this SCC colony was 761 psi, 114% of NEB-approved MOP, or 191% of the current reduced operating pressure. The deepest SCC colony found in the field that corresponded to a reported feature had a depth of 2.2 mm (35% of WT); the corresponding tool reported depth for this SCC colony was 1.6 mm (25% of WT).
- 78 were found to be CL features. The most severe CL indication found in the field had a predicted failure pressure of 764 psi, 112% of the NEB-approved MOP, or 192% of the current reduced operating pressure; the corresponding tool predicted failure pressure for this indication was 843 psi, 124% of the NEB-approved MOP, or 212% of the current reduced operating pressure. The deepest feature found in the field that corresponded to a reported feature had a depth of 2.4 mm (37% of WT); the corresponding tool reported depth for this feature was 2.6 mm (40% of WT).
- There were 50 unreported features found in the field with length and depth dimensions larger than that of the tool reporting threshold and were thus classified as false negative features. A discussion of false negative features is provided in Section 4.3.5.1 below.

4.3.5.1 False Negative Features

As mentioned in the previous section, there were a total of 206 unreported features (193 CL features and 13 SCC colonies) that had field measured length and depth dimensions that were larger than the tool reporting threshold and were thus classified as a false negative features. The tool specification says that in order for a feature to be classified as a false negative, the feature must have a depth of 1 mm for the entire length of 60 mm.

Shown in Figure 4.35, the lowest predicted failure pressure of the 193 false negative CL features is equal to 125% of the NEB-approved MOP, while the shortest remaining life of these 193 features is 36 years (refer to Figure 4.36 and Table 4-10). Thus, based on this information, CL features not reported by the crack detection tool can be managed through ILI feature detection enhancements, subsequent ILI, and pipeline rehabilitation, and do not pose an immediate threat to the integrity of the pipeline.

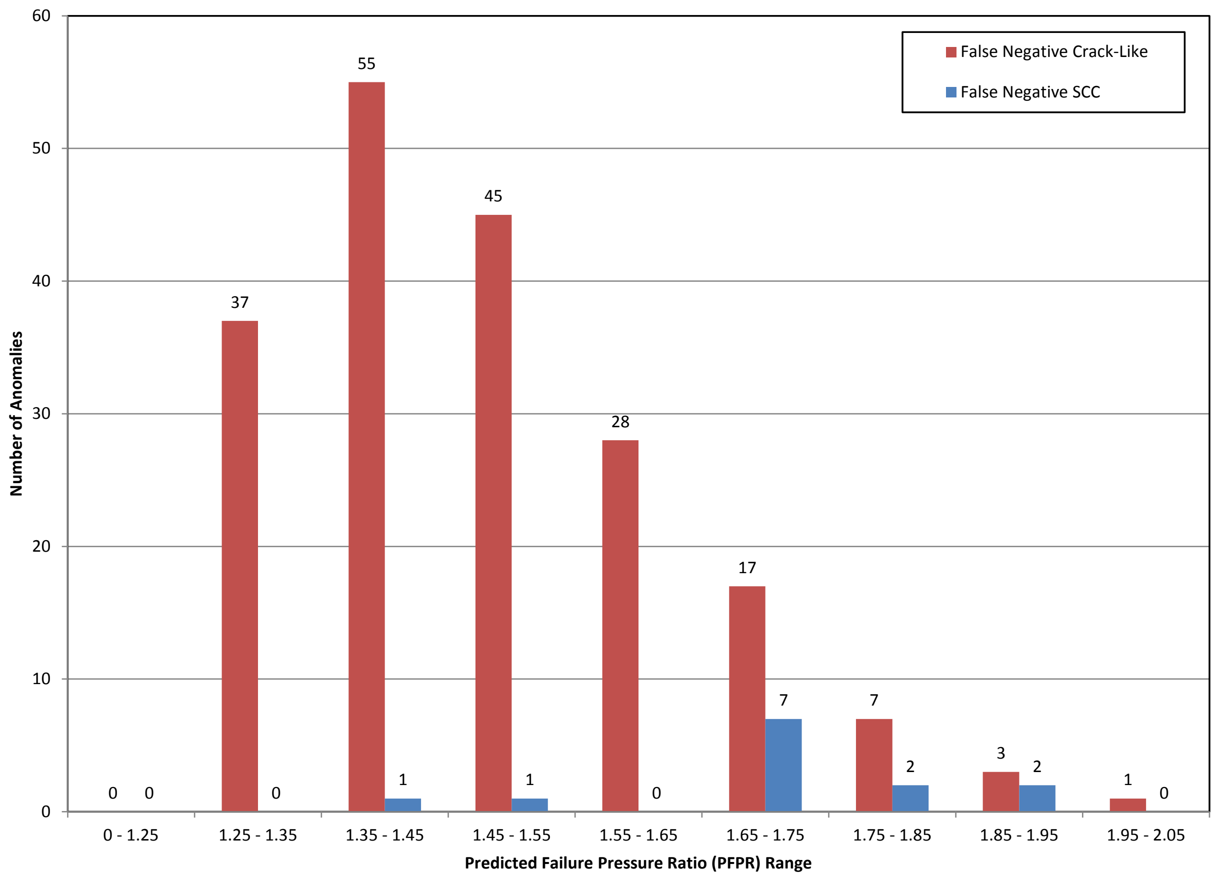
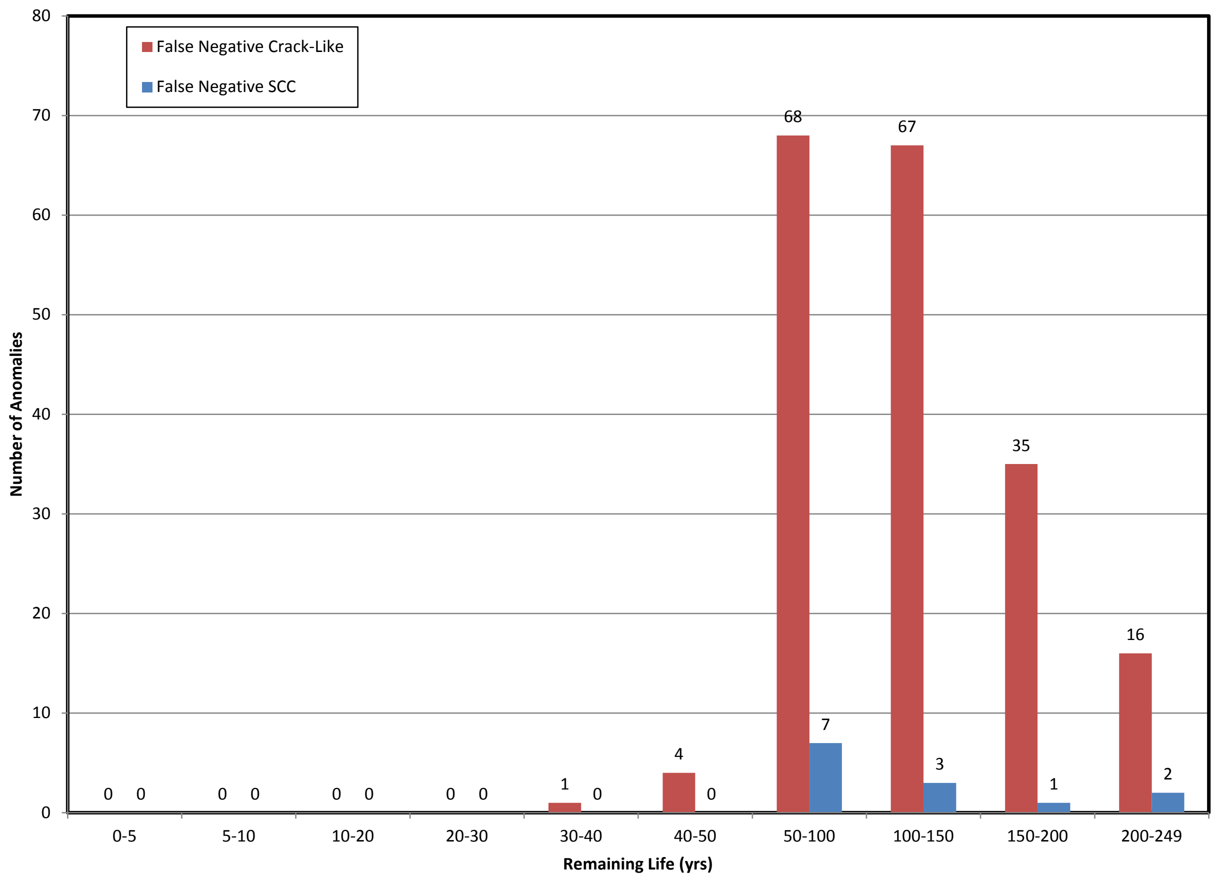


Figure 4.35 - Predicted Failure Pressure Ratio Distribution
(False Negative Features Detected in the Field)



Note: Assumed dimensions of the false negative features used in the predicted failure pressure calculation are as follows: a) CL features: the total field measured length of the CL feature and the field measured depth b) SCC features: the field measured interlinked length of the SCC feature, if available, or the total field measured length of the SCC feature and the field measured depth.

Figure 4.36 - Calculated Remaining Lives of False Negative Features

Table 4-10 - False Negatives
CL Features with a Calculated Remaining Life < 50 Years

Section	Approx. MP of feature (miles)	GIRTH WELD	RELATIVE POSITION	RADIAL POSITION	WT (in)	Flaw Length (mm)	Flaw Depth (% WT)	Predicted Failure Pressure (psi)	Predicted Failure Pressure (% MOP)	Remaining Life (years)
CD-ML	477.79	56930	aw	e	0.25	800	26%	784	148%	36.0
CD-ML	481.09	52350	aw	e	0.25	1070	23%	823	156%	47.1
CD-ML	477.79	56930	aw	e	0.25	330	24%	837	158%	47.7
CD-ML	477.79	56930	aw	e	0.25	500	23%	836	158%	49.1
HL-CD	374.67	20170	aw	e	0.25	175	31%	831	126%	49.3

When assessing whether or not an unreported SCC colony exceeds the tool reporting threshold, it is Enbridge's practice to use the longest continuous length of cracking (interlinked length) within the colony as opposed to the total field measured length of the SCC colony. This interlinked length provides a more accurate assessment of the actual severity of the cracking within the SCC colony as the cracking may not actually be continuous throughout the overall length.

Illustrated in Figure 4.37, the field measured interlinked length is typically significantly shorter than that of the total field measured length of the SCC colony. There are a total of 87 unreported SCC colonies depicted in Figure 4.37, which, based on their total field measured length, could be classified as false negative features; however, only two of those SCC colonies should be classified as false negative features based on their field-measured interlinked lengths. There were an additional 11 unreported SCC colonies whose total length exceeded the tool reporting threshold but for which there were no field measured interlinked lengths provided. In order to be conservative, these 11 SCC colonies were also classified as false negative features. As shown previously in Figure 4.35, the lowest predicted failure pressure of these 13 false negative SCC features is equal to 140% the NEB-approved MOP, while the shortest remaining life of these 13 features is 69 years, as shown in Table 4-11. Thus based on this information, SCC colonies not reported by the crack detection tool can be managed through ILI feature detection enhancements and subsequent ILI and pipeline rehabilitation, and do not pose an immediate threat to the integrity of the pipeline.

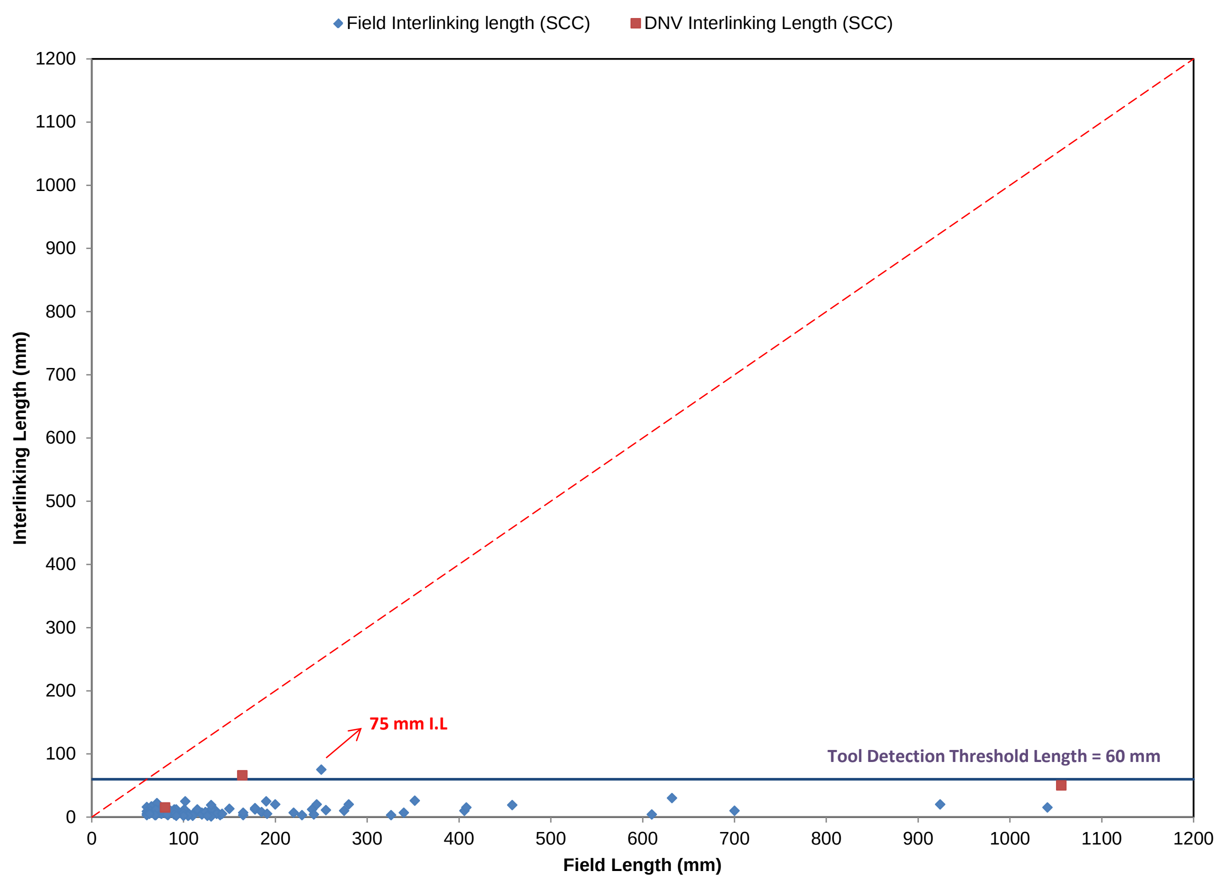


Figure 4.37 - Total Field Measured Length vs. Longest Indication (or DNV Verified Longest Interlinking Length) for Unreported SCC Features

Table 4-11 - False Negatives
SCC Features with a Calculated Remaining Life < 100 Years

Section	Approx. MP of feature (miles)	GIRTH WELD	RELATIVE POSITION	RADIAL POSITION	WT (in)	Flaw Length (mm)	Flaw Depth (% WT)	Predicted Failure Pressure (psi)	Predicted Failure Pressure (% MOP)	Remaining Life (years)
CD-ML	481.28	52080	aw	e	0.25	280	19%	882	166%	69.4
CD-ML	459.06	83420	aw	e	0.25	665	17%	887	167%	75.1
CD-ML	463.99	76480	aw	e	0.25	235	18%	905	168%	80.6
CD-ML	481.03	52430	bm	e	0.25	160	20%	894	169%	80.8
CD-ML	463.99	76480	aw	e	0.25	340	16%	902	168%	82.2
CD-ML	494.03	34150	aw	e	0.25	204	16%	933	181%	87.7
CD-ML	463.99	76480	bm	e	0.25	210	16%	923	172%	97.7

4.3.6 POD and Probability of Sizing ("POS")

The minimum reporting threshold of the GE UltraScan™ Crack Detection tool, as stated by GE, for the three tool runs conducted between 2004 and 2006 on Line 9B was a depth of ≥1 mm (0.039 inches) and a length ≥60 mm.

A feature that just meets this minimum reporting threshold requirement in Line 9B would have a predicted failure pressure of between 1001 psi and 2050 psi, depending upon the assumed pipe WT. This compares favorably to both the current reduced operating pressure (260 to 398 psi), and the maximum NEB-approved operating pressure (362 psi to 876 psi).

Enbridge assesses POD for CL, NL and CF features. The demonstrated ability of the crack ILI tool to detect and identify cracking threat is assessed using the following relationship:

$$POD = \frac{n_{rep}}{n_{rep} + n_{unrep}}$$

n_{rep} = number of ILI features reported

= number of false negative features that exceed ILI reporting threshold

In the case where field non-destructive examination ("NDE") identified an unreported crack flaw that was expected to be detected by the crack ILI tool, that flaw is identified as an outlier and drives further review by the field non-destructive examination and the ILI vendor. Additionally, the outlier is identified as a false negative within the trending and is included within determination of the re-inspection interval.

The POD values calculated for the reportable CL, NL and CF features are shown in Table 4.12 to 4.14 and are summarized below on a per section basis.

- ML to CD: The POD is 84% for the combined CL and NL features while it is 81% for CF features.
- CD to HL: The POD is 52% for the combined CL and NL features while it is 94% for CF features.
- HL to NW: The POD is 57% for the combined CL and NL features while it is 92% for CF features.

The low POD can be attributed to the observed false negatives in the field. These false negatives, shown in Section 4.3.5.1, do not to pose immediate threat to the integrity of Line 9B, most especially at the current reduced operating pressure.

Enbridge does not use conservative trending results as a justification for not mitigating features meeting fitness-for-service criteria. To reflect this bias towards crack ILI calibration, Enbridge calculates the POS as the number of features discovered to exceed the depth bin range reported in the ILI feature listing as per the equation below. The POS results are not utilized to adjust the fitness for purpose calculations; rather Enbridge works with the ILI vendor to have them calibrate the full report. Therefore, Enbridge calculates the POS as the number of features discovered to exceed the depth bin range it was reported in as per the equation below.

$$\mathrm{POD} = \frac{\mathrm{n_{rep}}}{\mathrm{n_{rep+}n_{unrep}}} POS = \frac{Number \cdot of \cdot correlated \cdot anomalies \cdot with \cdot depth \cdot below \cdot X}{Total \cdot number \cdot of \cdot correlated \cdot anomalies}$$

Note: Only features with depths confirmed by grinding were used for the above POS calculation. The grind profile is considered more accurate than UT NDE methods in evaluating the depth and predicted failure pressures of cracks.

Enbridge currently calculates POS two ways: first, by using the upper bound of the reported depth bins as the value X; and second, by using the upper bound of the reported depth bins plus one tool tolerance. These are reported as “POS based on Unity” and “POS based on +1 Tool Tolerance” in Tables 4-12 to 4-14 respectively. Enbridge currently uses a minimum of one tool tolerance as part of its crack ILI program selection and for determining crack ILI re-assessment intervals; as such, this value is representative of the integrity management processes currently utilized by Enbridge. (Note**:** At the time these three tool runs were completed, Enbridge had not yet implemented its current practice of adding +1 tool to the reported depth bin; however, POS values based on this approach are provided for comparative purposes.)

**Table 4-12 - POD and Identification (ML-CD)
based on the 2004 GE UltraScan™ Crack Detection Tool Data and Associated Field Data**

		ILI Reported Feature							
		CL	NL	CF	ML	GEO	IL	ND	False Negative*
Field NDE Reported Flaw	SCC	37	33	28	225	0	0	1	10
	crack	50	45	16	98	0	0	1	33
	dent	0	0	0	0	0	0	0	0
	inclusion	0	0	0	0	0	3	0	0
	metal loss	4	0	0	0	0	0	0	0
	geometric reflector	0	0	0	0	1	0	0	0
	False Positive	0	0	0	1	0	0	0	0
	Total	91	78	44	324	1	3	2	43
	POD	73%	100%	81%	N/A	N/A	N/A	N/A	
		84%							
	POI	55%	N/A	64%	N/A				
	POS based on Unity	100%	80%	81%					
	POS based on +1 Tool Tolerance	100%	92%	100%					

*exceeding crack In-Line Inspection reporting threshold for length and depth

**Table 4-13 -POD and Identification (CD-HL)
based on the 2006 GE UltraScan™ Crack Detection Tool Data and Associated Field Data**

		ILI Reported Feature							
		CL	NL	CF	ML	GEO	IL	ND	False Negative*
Field NDE Reported Flaw	SCC	13	0	14	161	0	0	0	1
	crack	75	32	2	5	0	0	0	112
	dent	0	0	0	0	0	0	0	0
	inclusion	0	0	0	0	0	0	0	0
	metal loss	0	0	0	0	0	0	0	0
	geometric reflector	0	0	1	0	0	0	0	0
	False Positive	0	0	0	0	0	0	0	0
	Total	88	32	17	166	0	0	0	113
	POD	44%	100%	94%	N/A	N/A	N/A	N/A	
		52%							
	POI	85%	N/A	82%	N/A				
	POS based on Unity	69%	22%	65%					
	POS based on +1 Tool Tolerance	81%	53%	94%					

*exceeding crack In-Line Inspection reporting threshold for length and depth

Table 4-14 - POD and Identification (HL-NW)
based on the 2005 GE UltraScan™ Crack Detection Tool Data and Associated Field Data

		ILI Reported Feature							
		CL	NL	CF	ML	GEO	IL	ND	False Negative*
Field NDE Reported Flaw	SCC	0	0	36	63	0	0	0	2
	crack	53	10	3	6	0	1	0	48
	dent	0	0	0	0	0	0	0	0
	inclusion	0	0	0	0	0	0	0	0
	metal loss	0	0	0	0	0	0	0	0
	geometric reflector	0	0	0	0	0	0	0	0
	False Positive	0	0	0	0	0	0	0	0
	Total	53	10	39	69	0	1	0	50
	POD	52%	100%	95%	N/A	N/A	N/A	N/A	
		57%							
	POI	100%	N/A	92%	N/A				
	POS based on Unity	74%	10%	51%					
	POS based on +1 Tool Tolerance	89%	50%	64%					

*exceeding crack In-Line Inspection reporting threshold for length and depth

POS is calculated for CL, NL, and CF features as other feature classifications do not have a reported depth. The calculated POS values for the various feature classifications are summarized below on per section basis.

- **ML to CD:**
  - The POS for CL features is 100% based on Unity and +1 Tool Tolerance.
  - The POS for NL features is 80% based on Unity and 92% based on +1 Tool Tolerance.
  - The POS for CF features is 81% based on Unity and 100% based on +1 Tool Tolerance.
- **CD to HL:**
  - The POS for CL features is 69% based on Unity and 81% based on +1 Tool Tolerance.
  - The POS for NL features is 22% based on Unity and 53% based on +1 Tool Tolerance.
  - The POS for CF features is 65% based on Unity and 94% based on +1 Tool Tolerance.
- **HL to NW:**
  - **The** POS for CL features is 74% based on Unity and 89% based on +1 Tool Tolerance.

- o The POS for NL features is 10% based on Unity and 50% based on +1 Tool Tolerance.
- o The POS for CF features is 51% based on Unity and 64% based on +1 Tool Tolerance.

The uncertainties associated with the tool's depth sizing ability were incorporated into the remaining life assessments discussed in Section 4.3.8.

4.3.7 Depth and Predicted Failure Pressure Field-Tool Trending Analysis

A variety of field-tool trending analyses were undertaken to evaluate the accuracy associated with the 2004, 2005 and 2006 crack detection ILI runs conducted between NW and ML. The analyses focused on quantifying the tool's performance with respect to accurately measuring the depth as well as the fitness for purpose of the reported features. Provided below is a discussion of the key findings associated with the different analyses undertaken.

Unity Plots

Figures 4.38 through 4.43 compare the tool reported dimensions (depth and fitness for purpose) with the corresponding field measured dimensions for those tool reported features that have been excavated. These "unity plot" graphs show diagonal lines where data would fall if perfect agreement was achieved between the field and ILI data, with conservative results being below the diagonal line pertaining to the depth comparisons graphs, and above the diagonal line on the fitness for purpose graphs.

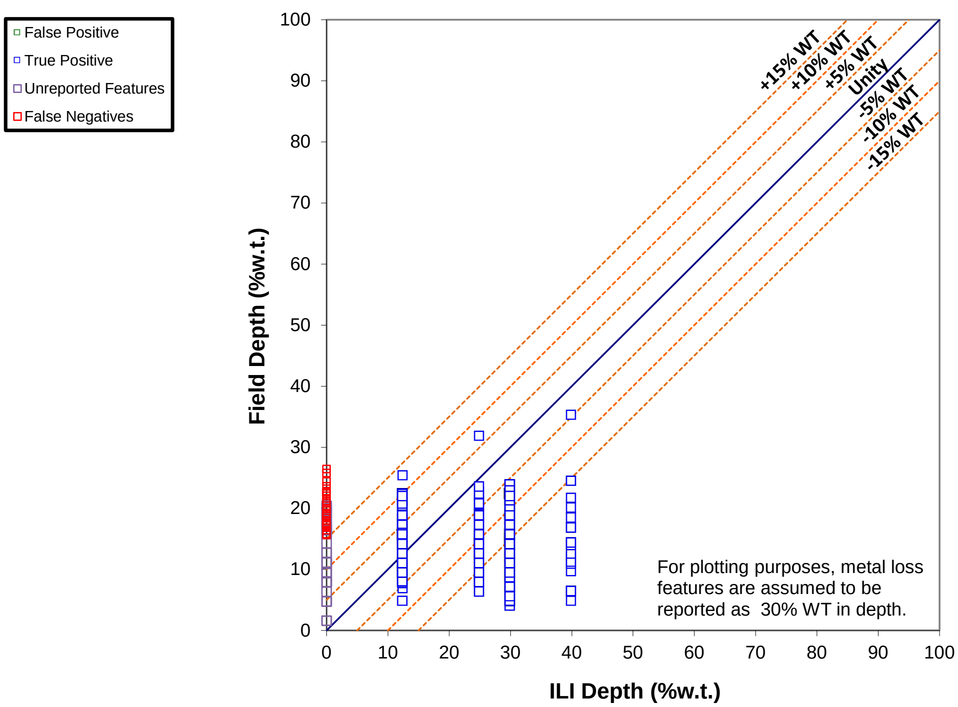
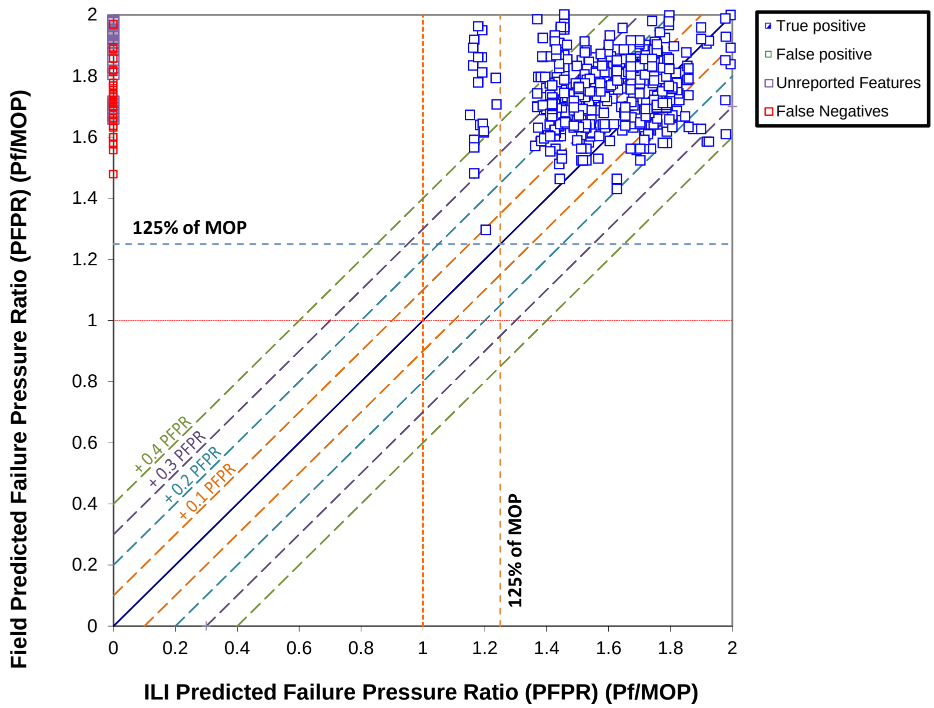
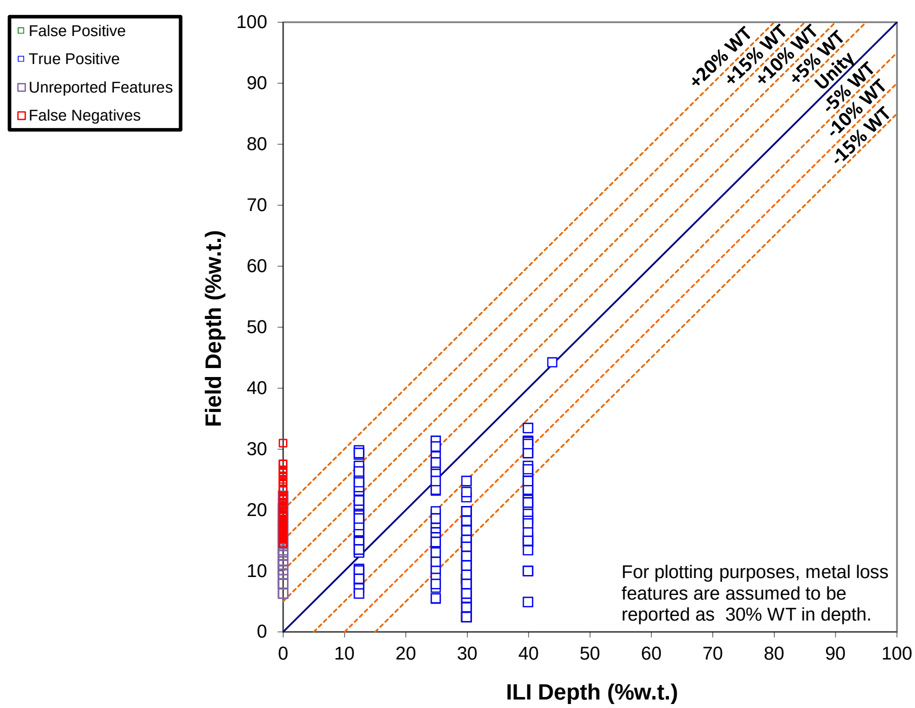


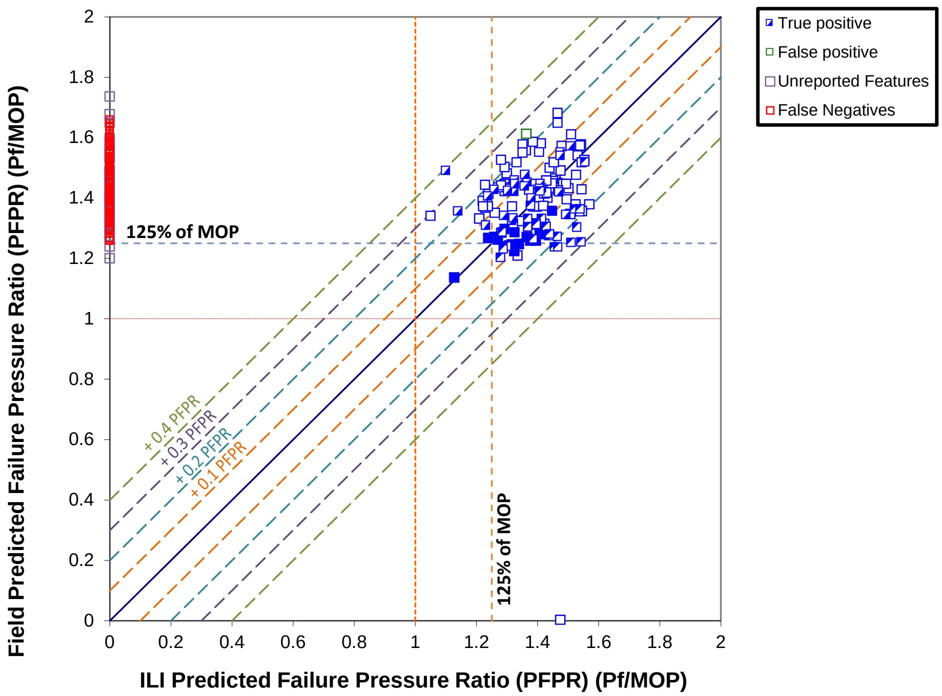
Figure 4.38 - Depth Unity Plot based on the 2004 USCD (ML-CD)



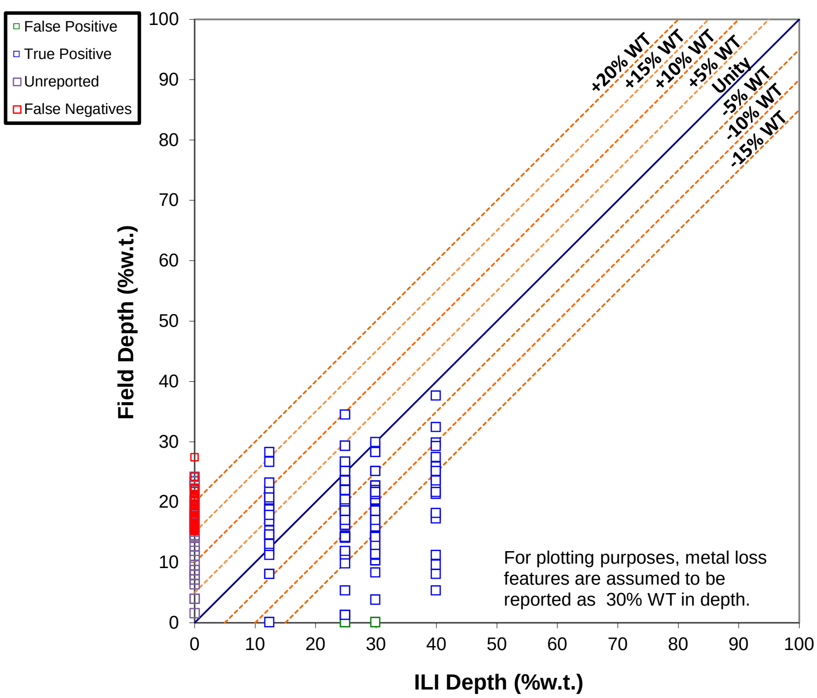
1 **Figure 4.39 - Fitness-for-Purpose Unity Plot based on the 2004 USCD (ML-CD)**



2 **Figure 4.40 - Depth Unity Plot based on the 2006 USCD (CD-HL)**



1 **Figure 4.41 - Fitness-for-Purpose Unity Plot based on the 2006 USCD (CD-HL)**



2 **Figure 4.42- Depth Unity Plot based on the 2005 USCD (HL-NW)**

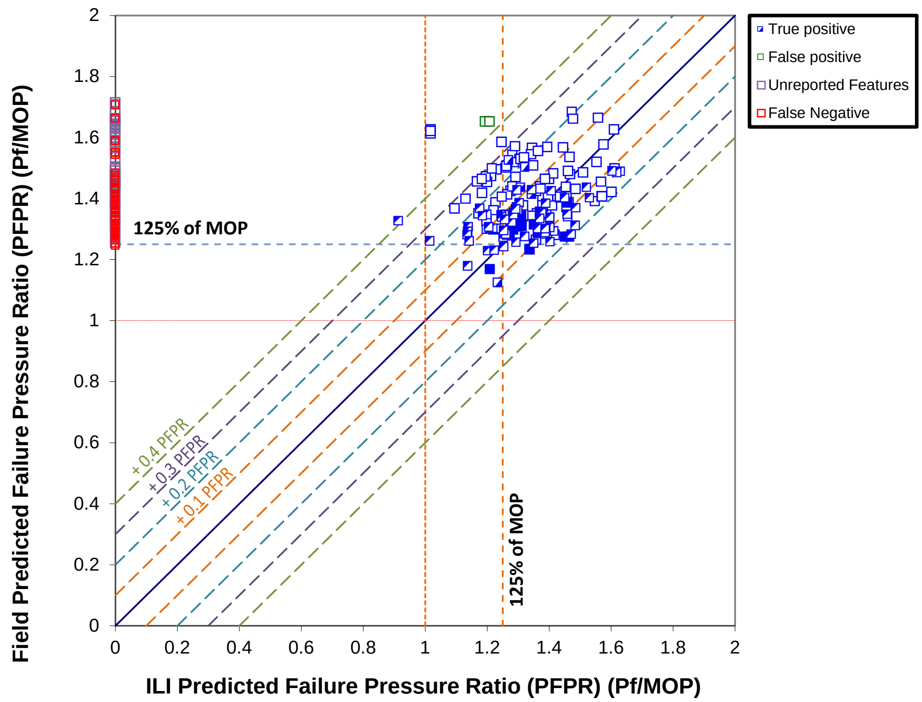


Figure 4.43 - Fitness-for-Purpose Unity Plot based on the 2005 USCD (HL-NW)

The data is considered to be sufficiently accurate if the field measured depths fall within ± 5% of the pipe WT of the tool reported depths (Figures 4.38 , 4.40 and 4.42), and the field predicted failure pressure ratios ("PFPR") fall within ±0.1 of the tool predicted failure pressure ratio (Figures 4.39 , 4.41 and 4.43). Non-conservative outliers are investigated in order to determine their likely cause. Feedback is provided to the ILI vendor for the purpose of immediate or future tool calibration.

Illustrated in Figures 4.38, 4.40 and 4.42 the USCD has challenges accurately sizing features with a reported depth <12.5% of the pipe WT. This coincides with Enbridge's and industry's experience. These challenges are understandable since this depth is below the actual reporting threshold of the tool. However, the GE UltraScan™ Crack Detection tool was able to accurately or conservatively size those features with a reported depth >12.5% of the pipe WT, which are the features that are in fact above the reporting threshold of the tool, as summarized below.

- **ML to CD**
  - **12.5% to 25% depth bin:** 99% of field measured depths <+5% of tool measured depth
  - **25% to 40% depth bin:** 100% of field measured depths <+5% of tool measured depth
- **CD to HL**
  - **12.5% to 25% depth bin:** 93% of field measured depths <+5% of tool measured depth

    - **25% to 40% depth bin:** 100% of field measured depths <+5% of tool measured depth

- **HL to NW**
    - **12.5% to 25% depth bin:** 98% of field measured depths <+5% of tool measured depth
    - **25% to 40% depth bin:** 100% of field measured depths <+5% of tool measured depth

Figures 4.39, 4.41 and 4.43 illustrated that there is considerable scatter in the field-predicted failure pressure ratios relative to the corresponding tool-predicted failure pressure ratios. Some of this scatter can be attributed to the manner in which the field NDT contractor measured and recorded the lengths of the field detected features. Subsequent to the completion of the excavation programs on these three segments of Line 9B, Enbridge developed and implemented detailed reporting requirements that field NDT contractors must adhere to when recording measurements of field detected features. These requirements have reduced the amount of scatter in the field-tool correlations involving predicted failure pressure ratios.

However, notwithstanding the manner in which the field NDT contractor previously measured and recorded the lengths of the field detected features, the lowest field predicted failure pressure corresponding to a tool reported feature with a predicted failure pressure >125% MOP was 120% MOP. This particular feature would have had an expected remaining life of 51 years if it had not subsequently been repaired by Enbridge.

Although the GE UltraScan™ Crack Detection tool did not provide depths for the reported metal loss features, Figures 4.38, 4.40 and 4.42 illustrate that the field-measured depths corresponding to those features varied from 2% to 30% of the pipe WT.

4.3.8 Deterministic Remaining Life Assessment of 2004, 2005 and 2006 Crack Detection In-Line Inspection Data

Enbridge contracted Det Norske Veritas (Canada) Ltd. ("DNV") in 2012 to undertake this remaining life assessment based on the 4105 unexcavated crack-related features identified between NW and ML based on the 2004, 2005 and 2006 crack detection ILI data for the inclusion in this EA. The remaining life assessment considered growth from both a fatigue and SCC perspective. To ensure conservatism in establishing the actual remaining life for each adjusted tool-reported feature, the lesser of the calculated fatigue or SCC remaining life was assumed.

Provided below is the approach used by DNV to undertake that remaining life assessment, the assumptions used in the assessment, and the subsequent results.

4.3.8.1 Initial and Final Dimensions of Unexcavated Tool Reported Features

The findings from the field-tool depth correlations derived from the 2004, 2005 and 2006 tool runs and associated excavations, as discussed in Section 4.3.5, were used to identify the appropriate level of adjustments required to be made to the reported depth of each feature. It was determined that the following adjustments, on a section by section basis, should be made to the upper bound depth of the given reported depth bins in order to ensure that the remaining life assessment was conservative.

- **HL to NW**
  - **<12.5% depth bin:** +20% WT
  - **12.5 to 25% depth bin:** +10% WT
  - **25 to 40% depth bin:** +5% WT (although all of the field data are below the 1:1 line this value was selected for conservatism)
- **CD to HL**
  - **<12.5% depth bin:** +20% WT
  - **12.5 to 25% depth bin:** +10% WT
  - **25 to 40% depth bin:** +5% WT (although all of the field data are below the 1:1 line this value was selected for conservatism)
- **ML to CD**
  - **<12.5% depth bin:** +20% WT (although a +15% adjustment is appropriate based on field data)
  - **12.5 to 25% depth bin:** +10% WT
  - **25 to 40% depth bin:** +5% WT (although all of the field data are below the 1:1 line this value was selected for conservatism)

The final critical dimensions of each adjusted tool-reported feature were subsequently calculated using the CorLAS™ software. The CorLAS™ computer program was developed by DNV to calculate failure pressures and critical flaw dimensions for CL defects. CorLAS™ uses the J-fracture toughness ("J_C") as the failure criterion for CL flaws. The value of J_C is estimated from the Charpy V-Notch Value ("CVN in ft-lbs") using the following relation:

$$J_C = 12\ CVN / A_C$$

where A_C is the net cross-sectional area of the Charpy specimen. Past work has shown that the equation above provides accurate predictions of fracture toughness for pipeline steels[9,17].

The following assumptions were used as input into those calculations:

Flaw profile: rectangular profile based on the tool-reported total length and the adjusted depth.

Operating Pressure: At-site MOP associated with each feature based on an assessment of the most severe quarter of pressure data between 2004 and 2010 (refer to Section 4.3.8.2).

WT: the lesser of the nominal WT or the WT as measured by the UT wall measurement ILI tool.

Nominal yield strength for grade 359 MPa: 359 MPa.

Nominal tensile strength for grade 359 MPa: 455 MPa.

Flow strength: yield strength + 68.9 MPa.

Charpy V-notch impact toughness: 15 ft-lb.

4.3.8.2 Pressure Cycle Analysis

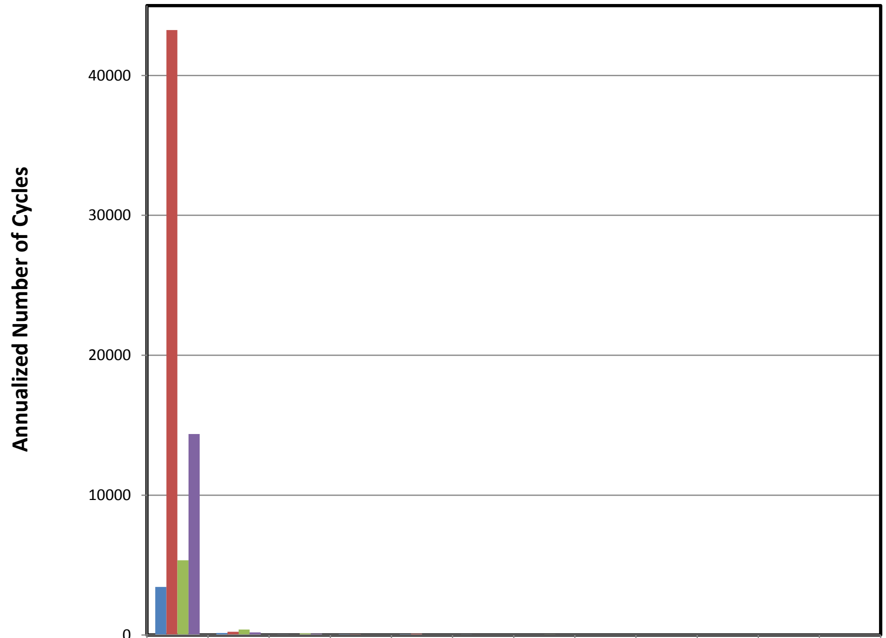
A loading spectrum is required for the fatigue and SCC remaining life calculations, which is obtained by performing a pressure cycle analysis on representative pressure data. Since the last crack inspection for each segment, pressure data was analyzed to find the most severe quarter of pressure cycling associated with each pump station and used to assess the remaining life of the reported crack related features in Line 9B. This analysis resulted in the selection of four different quarters of pressure data, one for each pump station to pump station segment between NW and ML. The pressure data received represents the current flow direction, and this data was used for crack growth calculations up until October 1, 2013. At this point in the analysis, each of these quarters of pressure data had their corresponding discharge and suction locations reversed in order to simulate the proposed flow reversal. These pressure histories were evaluated by the Rainflow Cycle Counting ("RCC") method to establish the number and magnitude of the various pressure cycles contained within the pressure data. This method of cycle counting is described in ASTM E1049, Standard Practices for Cycle Counting in Fatigue Analysis.[1]

Rainflow counting was developed to relate variable amplitude strain histories to constant amplitude fatigue data. Under nominally elastic conditions, the strain amplitude can be directly related to the stress amplitude. The technique is now widely used to relate variable amplitude fatigue loading to constant amplitude fatigue data. In typical pipeline applications, rainflow counting is applied to a representative pressure fluctuation history to produce cycle counts for a series of pressure ranges. The pressure ranges are then converted to stress ranges using the Barlow formula.

The quarters of pressure data chosen for the remaining life assessment are shown in Table 4-15. The resulting annualized cycles are shown in Figure 4.44. The vast majority (between 89 and 99%) of the pressure cycles associated with the four pump stations are relatively minor in nature (i.e. ≤ 50 psi). The actual operating pressure cycling associated with the proposed flow reversal will be further evaluated through pressure cycling monitoring and associated remaining life assessments once the flow has been actually reversed. The results of the RCC analysis were used in completing the remaining life assessment.

Table 4-15 - Most Severe Quarter of Pressure Data; between 2004 and 2010, Selected for Each Pump Station Segment

Pump Station Segment	Most Severe Quarter of Pressure Cycling
ML-TB	2005 Q2
TB-CD	2004 Q3
CD-HL	2010 Q2
HL-NW	2006 Q3



	50	100	150	200	250	300	350	400	450	500	550	600
Post-Reversal Operating pressure, North Westover	3442.0	157.0	47.1	70.7	66.7	43.2	11.8	0.0	0.0	0.0	0.0	0.0
Post-Reversal Operating pressure, Hilton	43244.6	238.0	19.8	67.5	95.2	27.8	4.0	4.0	4.0	4.0	0.0	4.0
Post-Reversal Operating pressure, Cardinal	5345.5	392.5	117.7	35.3	27.5	19.6	47.1	7.9	3.9	0.0	3.9	0.0
Post-Reversal Operating pressure, Terrebonne	14364.5	192.3	94.2	11.8	15.7	0.0	3.9	3.9	0.0	0.0	0.0	0.0

Pressure Bins (psi)

Figure 4.44 - RCC Results for the Four Pump Stations (ML-NW) based on the Most Severe Quarter of Associated Pressure Data used in Section 4.3.6

The results of the cycle counting were used to perform the SCC and fatigue crack growth assessments.

4.3.8.3 SCC Growth Rate Analysis

The cycle counting program described above is capable of determining the frequency and loading rate associated with each pressure cycle that is counted. This calculation is required for SCC growth analysis. The fatigue growth analysis calculates the damage per cycle, which is independent of the frequency of the cycle. The SCC growth analysis calculates the amount of SCC growth based on the crack tip strain rate, which is frequency and loading rate dependent.

To calculate the SCC growth rate, the cyclic frequency (f) is used in conjunction with the R-ratio (R), maximum stress intensity factor (K_{MAX}), a constant (C) and yield strength (σ_y) to calculate the veragecrack tip displacement rate ($\dot{\delta}$), as demonstrated in previous SCC research by Beavers[2] (see Equation 1).

$$\dot{\delta} = \frac{C}{\sigma_y}\left(f\ K_{MAX}{}^{2}(1-R)\right) \quad (1)$$

The K_{MAX} is computed using fracture mechanics principles utilizing the maximum pressure, nominal pipe dimensions and assumed crack dimensions. The dimensions of the reported crack related features used in these calculations are discussed in Section 4.3.6.1 above.

Beavers also demonstrated a relationship between crack tip displacement rate and crack velocity (v), which is:

$$v = 0.0049 \cdot \left(\dot{\delta}\right)^{0.5478} \qquad (2)$$

By knowing the crack tip displacement rate, the amount of crack growth is computed from the crack velocity and duration of each cycle. The damage for all cycles is then summed and divided by the time period for the pressure history to calculate the SCC growth rate.

The SCC remaining life for each adjusted tool-reported feature was calculated by dividing the amount of crack growth required for failure (i.e. the difference between the initial flaw size (adjusted tool reported dimensions) and the final flaw size (critical dimensions of adjusted tool reported at the at-site MOP) by the SCC growth rate calculated for each feature using the approach discussed above.

4.3.8.4 Fatigue Crack Growth

There are three fatigue crack growth regimes, as shown in Figure 4.45, where the cyclic crack growth rate (da/dN) is a function of the range of stress intensity factor (ΔK).

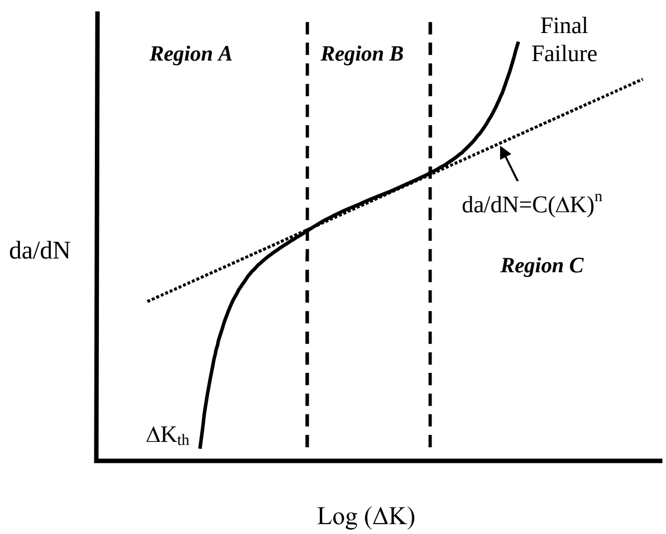


Figure 4.45 - Fatigue crack growth regimes represented as the cyclic crack growth rate (da/dN) as a function of the range in stress intensity factor (ΔK)

The range of stress intensity factor, ΔK, is a parameter relating to the cyclic stress and crack size and is the driving force for crack growth. This figure shows that crack initiation, propagation (growth), and final failure are exhibited in Region A, B, and C, respectively. The Paris region corresponds to Region B, where the cyclic crack growth rate is directly proportional to the range of stress intensity factor. The Paris Law[3, 4] was used to describe this relationship:

$$\frac{da}{dN} = C(\Delta K)^n \tag{3}$$

Where C and n are constants that depend on material and environment. Values for ΔK were calculated assuming a semi-elliptical surface crack[5,6]. Thus, the remaining fatigue life is calculated by integrating the Paris Law crack growth from the initial flaw size (adjusted tool reported dimensions) to the final flaw size (critical dimensions of adjusted tool reported feature at the at site MOP) using the pressure cycles calculated in Section 4.3.8.2 above.

These calculations were conducted at the upper-bound fatigue crack growth rates from API 579-1/ASME FFS-1[7]. Using the upper-bound fatigue crack growth should provide a lower bound (conservative) remaining life. For a cyclic crack growth rate (da/dN) in terms of inches per cycle and ΔK in terms of ksi-in$^{0.5}$, these upper bound rates correspond to the following Paris Law parameters:

- a coefficient of 3.60 x 10^{-10} and exponent of 3.00 for base material; and
- a coefficient of 8.61 x 10^{-10} and exponent of 3.00 for weld material.

4.3.8.5 Summary of Deterministic Remaining Life Assessment

Provided in Figure 4.46 is a graphical depiction of the calculated remaining lives of the reported crack related features in Line 9B between NW and ML. Based on the analysis discussed above, there are presently 25 reported features that are predicted to reach critical dimensions prior to the proposed flow reversal in October 2013. However, based on the current reduced operating pressures that Line 9B is operating under, none of the features would be expected to reach critical dimensions until December 2013. Enbridge is presently in the process of re-inspecting Line 9B between NW and ML and these 25 features will be re-evaluated based upon the new inspection data and repaired as required prior to the reversal of Line 9B. Any feature meeting excavation criteria will be repaired in order to operate the line at the required operating parameters prior to line reversal.

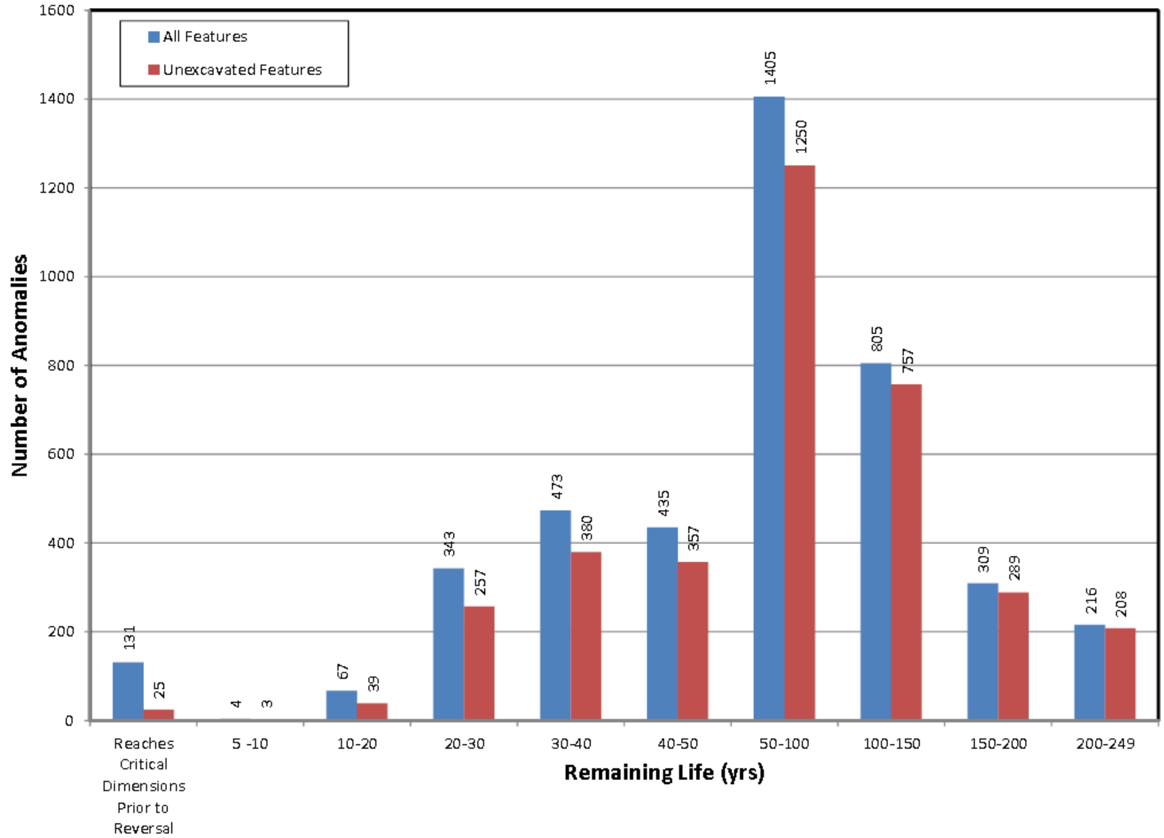


Figure 4.46 - Deterministic Remaining Life Assessment of USCD Reported Features in Line (NW-ML)

As illustrated in Figure 4.46, Enbridge's previous excavation programs successfully mitigated 127 of the 155 (82%) features that would be expected to reach critical dimensions, based on maximum at-site operating pressure, within the next 10 years.

4.3.9 Cracking Risk Profile Pre and Post Flow Reversal

The cracking risk profile associated with the portion of Line 9B between NW and ML, pre and post flow reversal, is depicted graphically in Figure 4.47. The risk profile was determined by Enbridge's Operational Risk Management specialists.

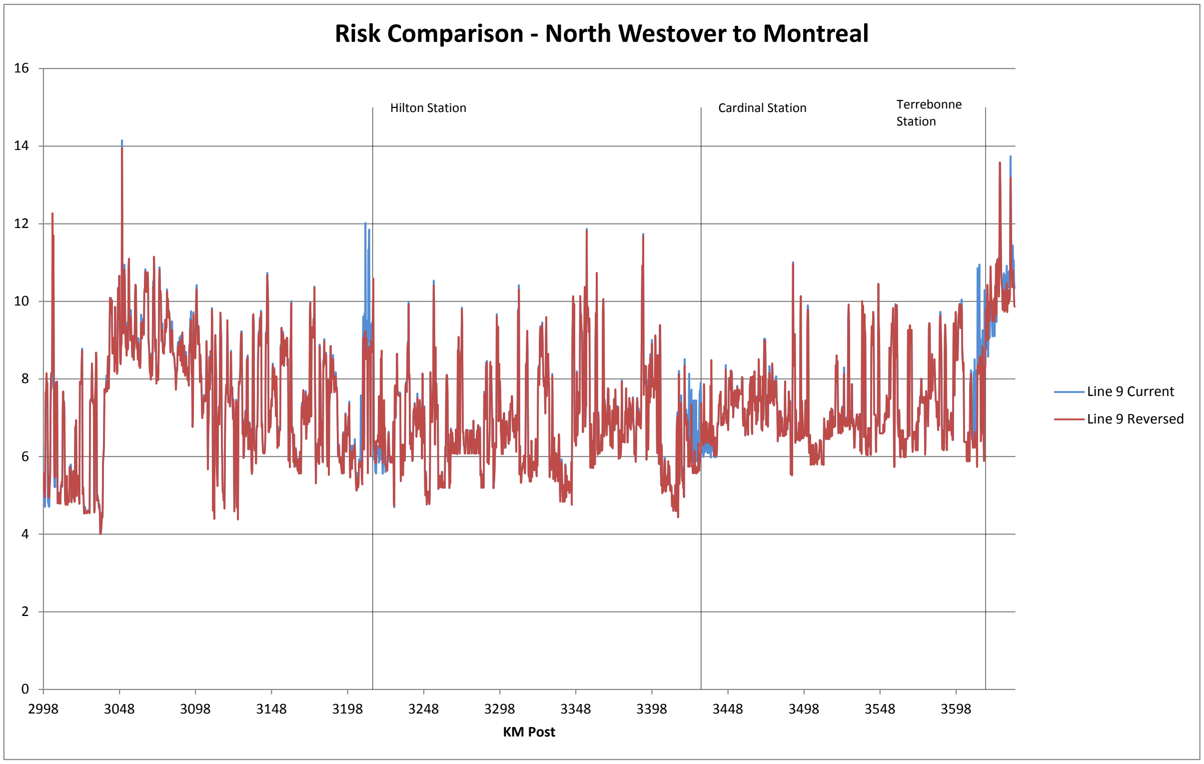


Figure 4.47 - Risk Profile for Line 9B (NW-ML) Pre and Post Flow Reversal

As would be expected, the planned flow reversal will result in increases of risk to the operation of the pipeline at the discharge side of the pump stations (North Westover, Hilton, Cardinal and Terrebonne) and corresponding decreases of risk at the suction side of the pump stations (Hilton, Cardinal, Terrebonne and Montreal). However, the overall changes to the risk profile as a result of the planned flow reversal are minimal, and the risk control and mitigation strategies currently being executed by Enbridge will effectively manage these risks.

4.3.10 Cracking Summary and Conclusions

Flow reversal, an increase in throughput, and the shipment of heavy crudes will not require any modifications to the manner in which the existing crack management program is developed or implemented.

Based on this EA, there are presently no features reported by the 2004, 2005 and 2006 crack detection inspections that are predicted to reach critical dimensions until December 2013 based on current reduced operating pressures. Any feature meeting excavation criteria will be repaired in order to operate the line at the required operating parameters.

The planned flow reversal will result in increases of risk to the operation of the pipeline at the discharge side of the pump stations (NW, HL, CD and Terrebonne ("TB")) and corresponding decreases of risk at the suction side of the pump stations (HL, CD, TB and ML).

Enbridge is presently inspecting Line 9B between North Westover and Montreal. Prior to the proposed flow reversal and resumption of normal operating pressures Enbridge will excavate and repair all features exceeding the acceptance criteria in place at that time for Line 9.

4.4 Mechanical Damage

Enbridge has a Mechanical Damage Management Plan ("MDMP") 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 rock. Also defined by ASME as "damage to the pipe surface caused by external forces", Enbridge refers to damage of this type as "Mechanical Damage". The focus of Enbridge MDMP is Delayed Failure, which is damage that may result in a failure sometime after the initial impairment (e.g. months or years after the damage occurs). The application of the MDMP to assess the condition of the pipeline consists primary of utilizing ILI technologies, coupled with field excavation programs.

4.4.1 Third Party Damage Prevention

Prevention is a key component to Enbridge's approach to mitigating the potential for mechanical damage to occur as a result of third party damage. The Enbridge Lands & Right of Way Department uses a comprehensive ROW monitoring and stakeholder awareness program to prevent damage to the pipeline system. Components of the program include:

- Public Awareness Program ("PAP");
- ROW signage;
- participation in local One Call organizations;
- participation in industry community awareness programs;
- depth of cover surveys; and
- ROW patrols.

Enbridge has succeeded in minimizing third party damage on its pipeline system through this approach to damage prevention.

4.4.2 Susceptibility to Mechanical Damage

Pipelines are susceptible to mechanical damage during construction or as a result of changing ROW conditions or damage resulting from third party contact during the operating life of the pipeline.

Mechanical damage that is sustained to the pipeline, whether it is residual from construction, experienced due to pipe or soil settlement post construction or created by undetected third party contact, is detected by ILI. Pipelines with a high diameter over thickness ("D/t") ratio (typically > 100) are more susceptible to mechanical damage than pipelines with a lower D/t ratio. With a D/t ratio of 120, Line 9 is susceptible. Enbridge's established integrity management systems including ILI data analysis, threat integration and dig selection can manage the mechanical damage threat on in-service pipelines, including Line 9.

4.4.3 Mechanical Damage Identification and Characterization

ILI tools that are utilized to detect deformation and potential mechanical damage include both geometry tools and metal loss tools. The primary 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.

Enbridge uses only high-resolution caliper inspection tools for the purpose of completing mechanical damage inspections throughout the pipeline system. 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 adopted by Enbridge. All caliper ILI tools utilized by Enbridge are proven to repeatedly detect dents that are 2% or greater in depth. The tools also detect dents less than 2% in depth, but tool specifications generally indicate that sizing of dents less than 1% in depth can be unreliable. Enbridge requires all dents equal to or greater than 2% that are detected by the caliper tools to be reported by the ILI Vendor in the ILI report.

Caliper technology can be supplemented with data from metal loss technology such as MFL or USWM to provide additional characterization of mechanical damage features with respect to stress concentrators (corrosion features, gouging, etc.) that may provide an initiation point for cracking to occur. All geometry features identified by metal loss technologies are reported, and those that are associated with secondary features such as metal loss, gouging or welds are evaluated; this includes features that may have depths less than 2% OD that do not meet the reporting criteria of the caliper ILI tools. This data is integrated with caliper data to determine actual dent depths to assist in determining the need for additional assessment or field investigation for individual features.

To mitigate features identified as potential threats, Enbridge has developed criteria for selection of features for potential field assessment. Selection of geometry features for field assessment is supported by the additional levels of characterization provided by integrating data from multiple ILI technologies. The excavation and field assessment criteria are based on Enbridge and industry experience and regulatory requirements.

- The Enbridge excavation criteria applicable to mechanical damage programs on this pipeline are:Dents >=6.0%
- Dents >=2.0% between the 8:00 and 4:00 radial positions (top-side)
- Dents >=2.0% on welds (weld position per metal loss tool)
- Dents >=2.0% associated with metal loss, or other stress risers
- Dents >=2.0% identified as having multiple apexes (“MAD”) and Dents In Close Proximity (“DICP”)

MADs and DICPs do not meet the historic excavation criteria. However, Enbridge has applied lessons learned from recent failures, which resulted in a heightened focus on geometric features with similar characteristics, and the Enbridge excavation criteria was subsequently updated to include the assessment of these types of features.

The processes and procedures included in the MDMP are applied universally to all pipelines in Enbridge’s system. Further, the processes and procedures are applied consistently across the system regardless of the MOP or operating pressure profile of a particular pipeline. Accordingly, the reversal of Line 9B will not result in any required changes to the management of mechanical damage as no change in MOP will occur.

The following sections provide a summary of the recent ILI data and excavation programs on the three inspection segments of Line 9B.

4.4.4 Recent Mechanical Damage Program Results

4.4.4.1 Montreal to Cardinal (ML-CD)

The segment between ML to CD stations was last inspected by a mechanical damage tool in 2007 by a GE CXR. Figures 4.48 and 4.49 illustrate the distribution of the features reported by the inspection. Figure 4.48 demonstrates the depth of the reported dents by Milepost, and Figure 4.49 demonstrates the orientation of the reported dents by Milepost.

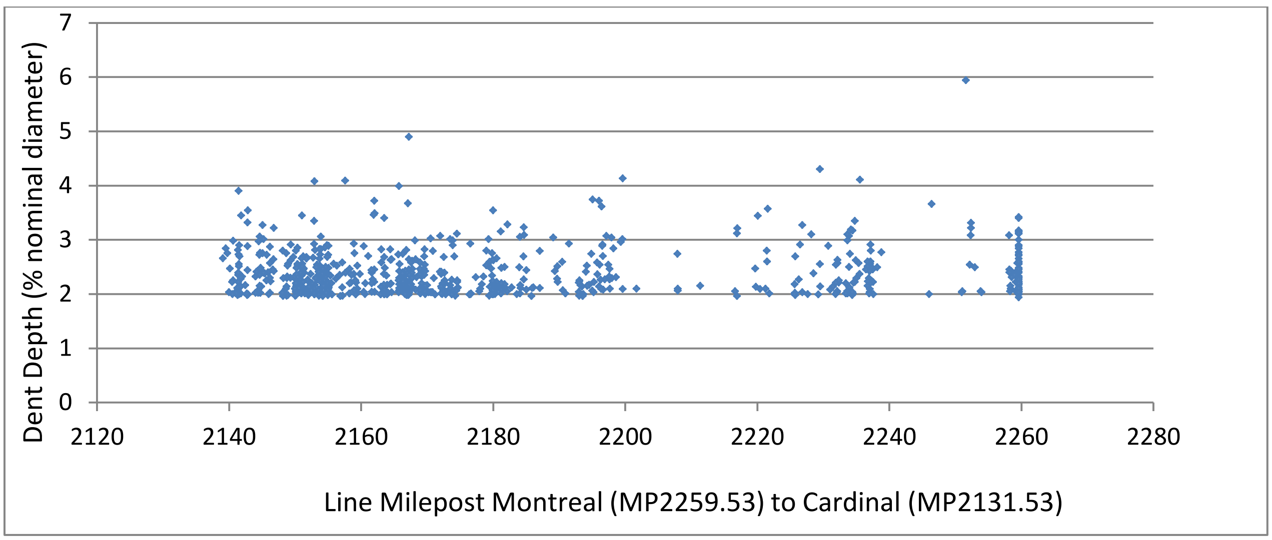


Figure 4.48- L9 (ML-CD) Dent >2% Depth
% of Nominal diameter vs. Location (Mile post) Distribution

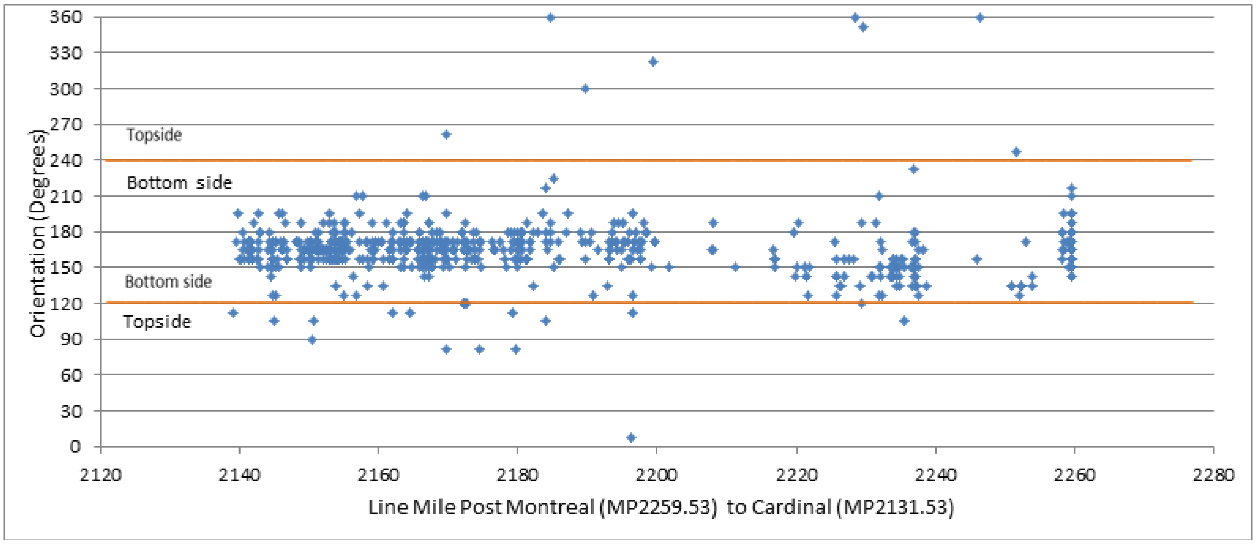


Figure 4.49- L9 (ML-CD) Dent >2%
Orientation (Degrees) vs. Location (Milepost) Distribution

The results of the 2007 GE CXR identified 12 features to be excavated, 11 because they met the excavation criteria and one for validation. The 12 features were excavated, field assessed and repaired according to Enbridge repair criteria.

The most recent metal loss tool run in this segment was the 2004 USWM, which identified two mechanical damage features that met excavation criteria. Both features were excavated, field assessed and verified as being geometric anomalies with metal loss, and were repaired according to the Enbridge repair criteria.

Features including DICP’s that have been reported by historic ILI tool runs will be assessed and validated with additional features identified by the 2012/2013 ILI data and will be addressed according to the Enbridge repair requirements.

4.4.4.2 Cardinal to Hilton (CD-HL)

The most recent caliper inspection of the pipeline segment between CD to HL stations was performed in 2000 by the BJ Geopig tool. Figures 4.50 and 4.51 illustrate the distribution of the reported features by the 2000 Geopig greater than 2% of nominal diameter over the length the segment from CD to HL. Figure 4.50 demonstrates the depth of the reported dents by Milepost, and Figure 4.51 demonstrates the orientation of the reported dents by Milepost.

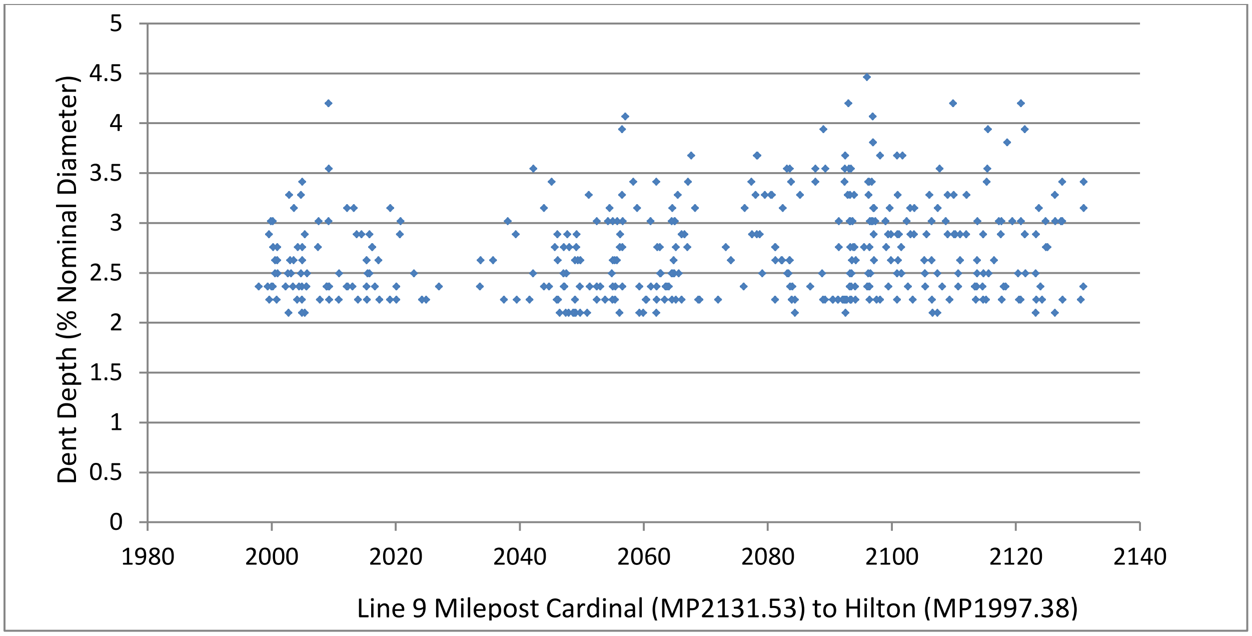


Figure 4.50- L9 CD-HL Dent >2% Depth
% of Nominal diameter vs. Location (Milepost) Distribution

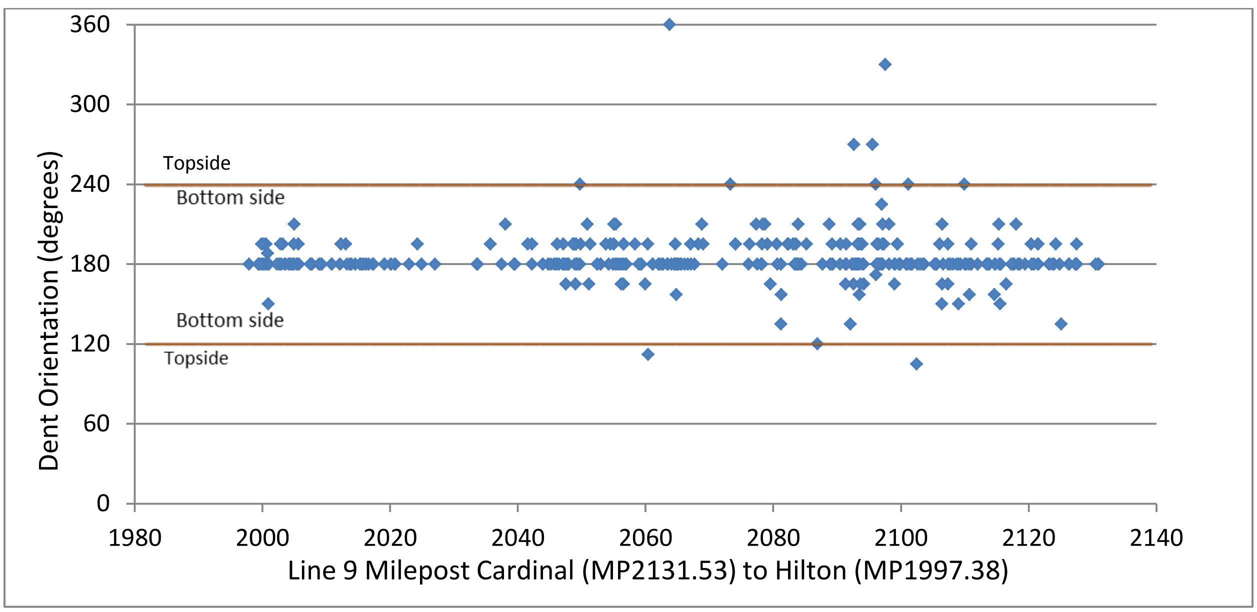


Figure 4.51- L9 CD-HL Dent >2%
Orientation (Degrees) vs. Location (Milepost) Distribution

Nine mechanical damage digs resulted from the 2000 BJ Geopig data, all of which were for reported topside plain dents. The field assessments and NDE confirmed the ILI data with six plain topside dents. The nine features were excavated, field assessed and repaired based on Enbridge repair criteria.

The 2006 USWM inspection identified 18 features that met repair criteria, including geometric anomalies associated with welds and secondary features. The 18 features were excavated, field assessed and repaired according to Enbridge repair criteria.

Features including DICPs and MADs have been reported in this segment by historic ILI tool runs will be assessed and validated with additional features identified by the 2012/2013 ILI data and will be addressed according to the Enbridge repair requirements.

4.4.4.3 Hilton to North Westover (HL-NW)

In 2005, a caliper inspection was performed on the HL to NW segment by a BJ Geopig. Figures 4.52 and 4.53 illustrate the distribution of the reported features by the 2005 Geopig greater than 2% of nominal diameter over the length the segment from HL to NW. Figure 4.52 demonstrates the depth of the reported dents by Milepost, and Figure 4.53 demonstrates the orientation of the reported dents by Milepost.

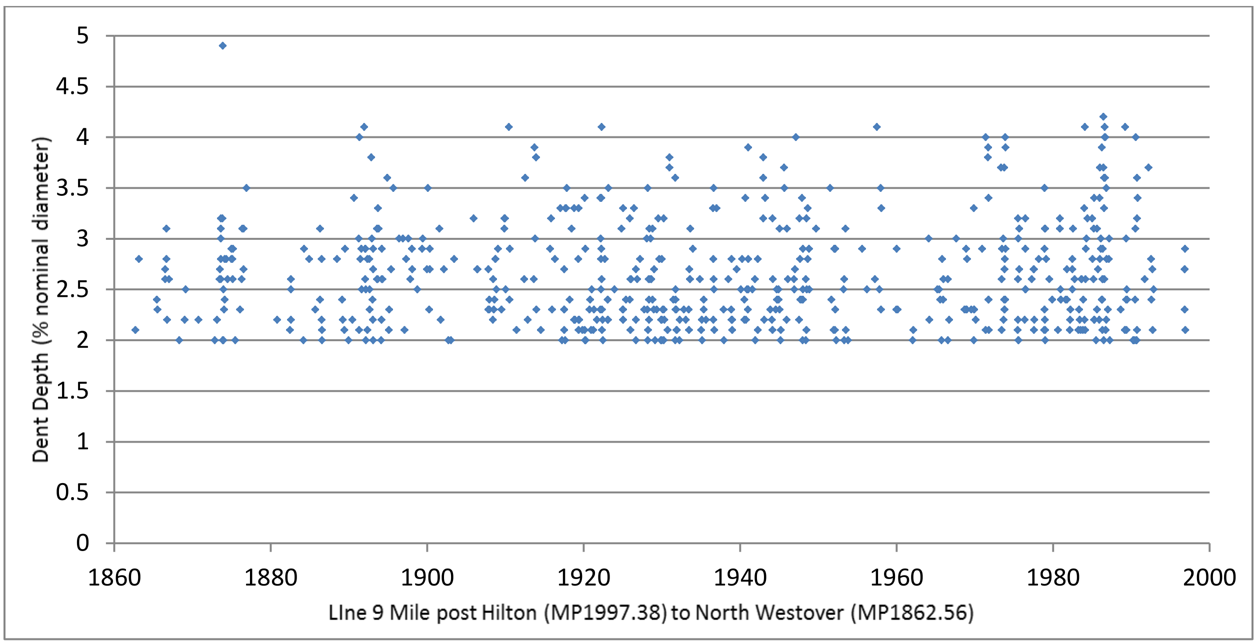


Figure 4.52- L9 HL-NW Dent >2% Depth
% of Nominal diameter vs. Location (Milepost) Distribution

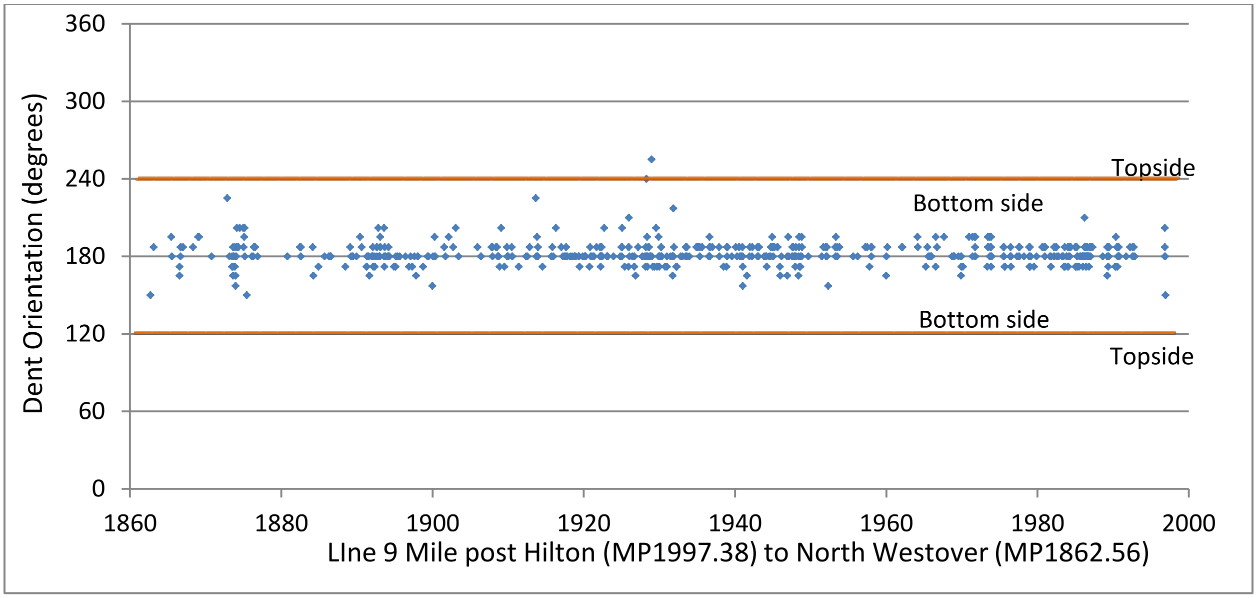


Figure 4.53- L9 HL-NW Dent >2%
Orientation (Degrees) vs. Location (Milepost) Distribution

No features that meet excavation criteria were identified in the 2005 BJ Geopig inspection.

In 2007 a GE MFL ILI was completed and augmented with 2005 GE USWM data. Four features were identified to meet excavation criteria based on the ILI data. The four excavations were excavated, field assessed and repaired based on Enbridge repair criteria.

Features including DICPs and MADs have been reported in this segment by historic ILI tool runs will be assessed and validated with additional features identified by the 2012/2013 ILI data and will be addressed according to the Enbridge repair requirements.

4.4.4.4 Mechanical Damage Summary

Table 4-16 provides an overview of the features reported by ILI tools for each segment of the pipeline. It outlines the number of reported dents, defined as a localized depression greater than or equal to 2% of the OD, for Line 9B per mile and the percentage of these dents that are on the top of the pipe (between the eight o'clock and four o'clock positions). Also presented are the number of dents reported by the most recent caliper detection tools (GE Caliper and Baker Hughes Geopig) and the number of geometric anomalies (including potential areas of deformation <2% of the OD reported by the metal loss tools (USWM and MFL)).

Table 4-16 - Mechanical Damage Feature Overview

Mechanical Damage Reported					
Segment	**Inspection**	**Dents>2% Dents/Mile**	**Dents>2% Topside**	**Inspection**	**Number of Geometric Features**
ML to CD	2007 GE Caliper	5.1	21 (3.2%)	2007 GE Caliper	654
				2004 GE USWM	2135
CD to HL	2000 BJ Geopig	6.8	9 (2.1%)	2000 BJ Geopig	419
				2006 USWM	1441
HL to NW	2005 Geopig	4.4	0	2005 Geopig	605
				2007 USWM/MFL	1006

Through the use of mechanical damage, metal loss and crack data, a number of digs targeting mechanical damage has been completed on these segments. Table 4-17 summarizes the number of mechanical damage excavations that were performed from 2001 to present.

Table 4-17 - Number of Mechanical Damage digs (2001 - Present)

Mechanical Damage Excavations	
Segment	**Excavations**
ML-CD	41
CD-HL	48
HL-NW	16

Nine documented leaks involving mechanical damage on the pipeline from ML to NW have occurred between 1978 and 1999, and all were permanently repaired by sleeving.

In response to lessons learned from recent mechanical damage failures experienced on other Enbridge pipelines, and to address preventative actions identified in the NEB Safety Advisory 2010-01, dated June 18, 2010, the MDMP has undergone recent enhancements. Such enhancements include: required reporting of features that may have characteristics consistent with leading indicators of mechanical damage such as DICP and MAD; measurement and recording of half peak heights to further quantify deformation shape; and the formalization of the Threat Integration process to overlay all ILI data to identify potential secondary features located within areas of deformation. In addition, Enbridge is involved in a number of industry research initiatives, including those driven by Pipeline Research Council International ("PRCI"), that are targeted at improving the understanding of geometric interactions with secondary features and their failure mechanisms.

4.4.5 Impact of Line Reversal on Mechanical Damage Features

Despite the presence of mechanical damage features on the pipeline, the operational changes proposed for the pipeline will not influence the threat due to existing mechanical damage features. Features that meet repair criteria specified in Canadian regulations have been or will be evaluated and mitigated prior to the implementation of the changes. The remaining dents and other geometric anomalies have experienced similar operating conditions when the pipeline flowed in its original eastward configuration, prior to the reversal in 1999. The shipping of heavier product will have no impact on the existing features. Additionally, the pressure that a geometry is exposed to has little impact in comparison to the pressure cycling it may undergo. The cycling of the proposed configuration is not expected to exceed those operating conditions previously indicated in Section 4.3 and will be monitored throughout the lifecycle of the pipeline.

Geometric features identified through subsequent ILI which meet the Enbridge repair criteria or are considered to be a potential threat to the integrity of the pipeline will be remediated as per the Enbridge integrity management plan.

4.4.6 Geohazard Management

Geohazards along the Line 9 ROW are comprised of slopes, river crossings, and other geotechnical movement conditions. They are effectively managed through a combination of monitoring, assessment, and remediation when required. The details of the Enbridge Slope, River Crossing, and Pipeline Movement Management processes for Line 9 are described below.

4.4.6.1 Slope Management

Routine ROW inspections are conducted bi-weekly in an effort to detect any area where slope instability might exist. In the event that slope instability is identified on or near the pipeline corridor, the site is assessed by Enbridge engineers and/or a geotechnical specialist. Based on this specialist review, it is evaluated whether the observed movement might affect the pipeline. These evaluations may lead to additional monitoring initiatives such as supplemental ROW patrols, scheduled geotechnical specialist inspections, slope instrumentation installations, or a combination of these activities. Alternatively, these assessments may lead to remediation requirements such as slope improvements, pipeline stress relief, or line relocation. Crossing slope remediation has been previously conducted at the banks of the Rideau Canal and West Duffin Creek, located at MP’s 2071 and 1930 respectively, along with various minor slopes that have exhibited cover erosion due to all-terrain vehicle traffic. These sites are closely monitored during ROW patrols for evaluation of the remediation performance.

There is one slope identified location along the Line 9 ROW that recently underwent slope stabilization remediation. The East Don River approach slope at MP 1915 exhibited a slumping event that was identified in April 2012. The slope movement was caused by subsurface artesian water pressures, which induced the seepage of sandy-silts out of the slope, and initiated associated ground subsidence. This settlement created vertical tension cracks in the ground, which acted to reduce the slope's resistance to the observed translational sliding. Line 9 runs across this slope, and the described slope movement caused a pipeline exposure in April 2012, as shown in Figure 4.54. Upon identification of the exposure, Enbridge engineers and geotechnical consultants immediately conducted an ILI review and on-site assessment. The ILI review demonstrated that there were no pipe wall integrity threats at the site. The on-site assessment results lead to the excavation of the slumped materials in order to reduce further soil loading. A stress relief was also conducted to allow for springback of the pipeline to near its original position, and strain gauges were installed to allow for direct pipe strain monitoring. The slope in the vicinity of the pipeline was subsequently remediated to improve its stability through cutting of the slope crest, constructing of a toe berm, and the installation of surficial drainage improvements, as shown in Figure 4.55 where the orange line indicates the pipeline location.

In October 2012, during planned ROW maintenance at the site, pipeline movements in the order of 400mm in the downslope direction were observed. While the corresponding strains were acceptable, in order to be conservative, a second stress relief was conducted. Inspections of the girthwelds within the movement zone accompanied the stress relief to allow for identification and repair of any anomalies. This ensured that the pipe section may safely accommodate potential future longitudinal strain and movement levels. Backfilling was completed in November 2012, and vertical monitoring tubes were installed to allow for direct monitoring of the pipe position. In consideration of the movement rates at the East Don River approach slope, Enbridge is planning to conduct a pipeline relocation from this site in 2013. Planning and preparation for the required permitting process is currently underway. The pipeline strain and position will continue to be monitored at scheduled intervals. Remediation will be conducted as required should the pipeline strains approach the allowable limits prior to the relocation.

Figure 4.54- East Don River Valley Approach April 2012

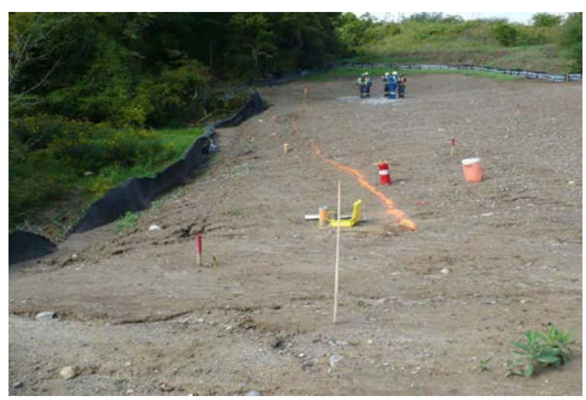


Figure 4.55- East Don River Valley Approach September 2012

4.4.6.2 River Crossing Management

River crossings are monitored through a combination of ROW patrols, depth of cover surveys, and engineering site visits as required. ROW inspections identify threats such as high water levels, river scour, debris, pipeline exposure, or other phenomenon that may affect the crossing integrity. Any such findings are communicated to Enbridge engineers and assessed for mitigation requirements. Depth of cover surveys are conducted every 10 years at minor crossings that exhibit lesser exposure risks, and every five years at major crossings. Should low cover near a river crossing be identified, the crossing is assessed for remediation requirements. The assessment includes evaluation of any ILI anomalies, unsupported spans, potential loading, river conditions, crossing location, and consideration of landowner consultations. Some examples of remediation options are pipeline armoring, line lowering, river re-routing, or line re-routing. Historically, remediation has been conducted near the Line 9 crossings of the Thames River and Soper Creek located at MP's 1805 and 1954, respectively. These sites are closely monitored during ROW patrols and depth of cover surveys to ensure that the pipe cover remains acceptable.

There is one river crossing site along the Line 9 ROW that is currently exposed and undergoing remediation preparations. A partial pipeline exposure at the MP 1923 Rouge River crossing was identified in 2010. The exposure was caused by bank erosion from the river, which extended beyond the pipeline sag bend. It was assessed by Enbridge engineers following its identification. In consideration of the corresponding ILI review, minor length, soil support, exposure location, and other considerations, it was ascertained that immediate remediation was not required, and planning was initiated to develop a long-term remediation solution. In consideration of the crossing proximity to a planned urban national park, Enbridge has worked closely with consultants and stakeholders to develop and implement an acceptable solution. Recently, a permit was received from the municipal regulatory authorities, and an NEB notification was filed for the remediation work. Remediation work is near completion.

4.4.6.3 Pipeline Movement Management

Locations on the ROW affected by ground settlement, frost heave, or unsupported spans are managed through a combination of ILI and ROW patrols. Caliper inspections are used to evaluate whether the bending stresses associated with pipeline movement are sufficient to generate pipeline wrinkles or buckles. There were no buckles or wrinkles identified in Line 9 during the most recent caliper inspections on Line 9B, as described in Section 3.4.4. ILI Inertial Measuring Unit ("IMU") technology has the capability of measuring pipeline bending through its on-board inertial unit, which collects GPS coordinates along the entire run section. Either a single run compared to assumed straight pipe, or run-to comparisons, allow for quantification of the pipe bending that has been induced by geotechnical movements. This profile difference is then used by ILI analysts to determine the associated bending strain. Enbridge has conducted an IMU inspection of all sections of Line 9, which would allow for the conducting of a bending strain analysis in a timely manner if required. There are currently no sites along Line 9 that require IMU bending strain analysis.

The longitudinal stresses at areas of pipeline movement identified from ROW patrols are evaluated using the criteria described in Section 4 of CSA Z662-11, when IMU strain data for the affected pipe section is not available. This evaluation is facilitated using field measurements such as survey, and considers the longitudinal effects of internal pressure, the temperature stresses, and the longitudinal stresses from bending. The combined longitudinal stresses are compared with the pipeline SMYS. Any locations along Line 9 where the longitudinal stresses exceed the allowable limits specified in CSA Z662-11 are remediated. There are currently no identified sites along Line 9 that require repair due to longitudinal stresses.

4.4.6.4 Impact of Line Reversal on Geohazard Management

Flow reversal is not expected to affect the management of geohazards along Line 9. Slope evaluations are conducted that consider observed geotechnical conditions, which are independent of flow conditions. Water crossings are similarly not affected by pipeline flow conditions. When evaluating pipeline movement stresses, the pipe section is evaluated based on MOP and the maximum expected temperature stresses. These assumptions do not consider actual operating conditions at the precise pipeline locations, resulting in conservative results for both pre and post flow reversal.

4.4.7 Mechanical Damage Summary and Conclusions

The processes and procedures included in the MDMP are applied universally to all pipelines in Enbridge's system. Further, the processes and procedures are applied consistently across the system regardless of the MOP or operating pressure profile of a particular pipeline. Accordingly, the reversal of Line 9B will not result in any required changes to the management of mechanical damage as no change in MOP will occur.

The reversal of the operation of the line will have minimal impact on the geometric features that are present in the line.

- Geohazards will continue to be monitored, assessed, and remediated as required. Management of geohazards are unaffected by flow reversal, as the Line 9 geohazards are predominantly unaffected by operating conditions.

5. PLANNED ACTIVITIES PRIOR TO FLOW REVERSAL

The following activities will be conducted on Line 9 from NW to ML prior to the flow reversal and capacity increase:

- conduct a comprehensive ILI program targeting metal loss, cracking and geotechnical features between ML and NW;
- evaluate the results of the ILI program and re-assess pipeline integrity based on 2012-2013 inspection data;
- determine what line rehabilitation activities are required to maintain the integrity of the pipeline; and
- execute required excavations and rehabilitate the pipeline to maintain pipeline integrity and meet the required operating parameters as per the Enbridge Integrity Management Plan.

6. CONCLUSION

The EA completed on Line 9 between ML and NW to evaluate corrosion, cracking, and mechanical damage threats indicates the following.

- There are no metal loss features in the pipeline section that require repair prior to the next metal loss inspections planned for 2012-2013.
- Fatigue cracking will continue to be managed at an acceptable level, and based on the results of the fatigue analysis, crack threat will not be aggravated by the proposed line reversal.
- Enbridge will continue to manage SCC.
- There are no mechanical damage features that require excavation prior to the proposed line reversal.
- Line reversal will not require a modification to the current Integrity management Plan for any of the aforementioned corrosion, cracking or deformation programs.

The overall results of this EA thereby demonstrate that the Project can proceed in a safe and reliable operating condition.

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