Enbridge Energy, Limited Partnership

Line 3 Permanent Deactivation Plan (U.S.)

MPUC Docket Nos. PL-9/CN-14-916 and PPL-15-137
OAH Docket Nos. 65-2500-32764 and 65-2500-33377

January 2017

TABLE OF CONTENTS

TABLES AND FIGURES

DEFINITIONS AND ACRONYMS

Abandoned Pipeline: A pipeline permanently removed from service that has been physically separated from its source of gas or hazardous liquid and is no longer maintained under regulation 49 CFR Parts 192 or 195, as applicable. Source: PHMSA Operations & Maintenance Enforcement Guidance, Part 195 Subpart F.

ASME: American Society of Mechanical Engineers.

CEPA: Canadian Energy Pipeline Association – CEPA is an organization whose mission is to enable companies to advance operations and develop safety and environmental innovations for the transmission pipeline industry through leadership and credible engagement between member companies, governments, the public and stakeholders. CEPA works together with companies to define and implement leading practices to continuously improve industry performance in three key areas: pipeline safety, environmental protection and socio-economics.

CFR: Code of Federal Regulations.

Cathodic Protection (CP): A technique used to control the corrosion of a metal surface, in this case a pipeline, by making it the cathode of an electrochemical cell. Most often this involves the application of a low level electrical current to the pipeline. Source: National Association of Corrosion Engineers (NACE) standard SP0169.

DNV GL: An international certification body and classification society whose main expertise is in technical assessment, advisory, and risk management. It is the world's largest technical consultancy to onshore and offshore wind, wave, tidal, and solar industries, as well as the global oil & gas industry - 65% of the world's offshore pipelines are designed and installed to DNV GL's technical standards.

Grouting: The use of an injectable mortar mix to fill in voids in soils, pipes or other cavities.

Hydraulic Vacuum Excavation (Hydrovac): Using pressurized water and a vacuum system to quickly and safely expose underground infrastructure. Pressurized water is injected into the ground through a handheld wand and as soil is liquefied, the resulting slurry is removed by powerful truck-mounted vacuum systems.

ISD: In-service date.

Line 3 Replacement Project: The Line 3 Replacement Project is the Minnesota portion of Enbridge's Line 3 maintenance driven replacement program and includes the replacement of approximately 282 miles of the existing 34-inch diameter Line 3 pipeline with approximately 340 miles of 36-inch diameter pipeline and associated facilities between the North Dakota/Minnesota border and the Minnesota/Wisconsin border.

Mainline Valves (MLVs): Mainline valves are designed and installed to isolate sections of the pipeline for maintenance purposes or in the event of a release. Valves are also required to be installed per federal pipeline safety regulations (49 CFR Part 195). The valves are remotely controlled by the Control Center to limit the extent of a release.

MP: Mile Post.

NORM: Naturally Occurring Radioactive Materials.

NPMS: National Pipeline Mapping System.

PCB: Polychlorinated biphenyl; any of a class of toxic aromatic compounds, often formed as waste in industrial processes.

Permanent Deactivation: Permanent deactivation as used by Enbridge herein means a pipeline permanently removed from service that has been physically separated from its source of gas or hazardous liquid.

PHMSA: Pipeline Hazardous Materials Safety Administration

Pipeline Inspection Gauge (PIG): Pigs are used for hydrostatic testing and pipeline drying, internal cleaning, internal coating, liquid management, batching, and inspection.

Pipeline Isolation: The separation of a pipeline from existing stations, terminals, and crossover connections to prevent the reintroduction of product.

Pipeline Segmentation: Employing methods such as: installation of a plug, cutting, and capping of the pipeline or closing of valves to effectively take the pipeline and turn it into smaller, hydraulically-independent sections.

O&MMs: Operations and Maintenance Manuals.

ROW: Right-of-way.

Water Conduit: Any physical pathway which fosters the conveyance of water.

1 EXECUTIVE SUMMARY

Enbridge's Line 3 pipeline was put into service in 1968. Line 3 is a 34-inch diameter, 1,097 mile long pipeline, which extends from Alberta, Canada to Superior, Wisconsin. The Minnesota portion of Line 3 includes approximately 282 miles of 34-inch pipeline, associated mainline valve sites, piping, pumps and manifold connections at the seven pump stations, and two terminals which facilitate the operation of the existing Line 3. As part of Enbridge's maintenance driven Line 3 Replacement Project, a new 36-inch diameter pipeline will replace Line 3. Once the Line 3 Replacement Project is permitted, constructed and placed into service, the existing Line 3 pipeline will be Permanently Deactivated.

Enbridge's Line 3 Permanent Deactivation Plan is based upon engineering assessments which considers risks to the environment, public safety, industrial entities (e.g., railway companies and utilities), and current land use. These assessments included detailed literature review, internal stakeholder consultation, the application of mitigation strategies to those identified risks, and the validation of the Permanent Deactivation Plan by assessing current pipeline conditions and modeling expected future pipeline conditions.

Enbridge conducted a risk assessment to determine the technical risks associated with the Permanently Deactivated pipeline. As part of this assessment, Enbridge assessed the relative risks of removing the pipeline and Permanently Deactivating it in place. Removing the 282 miles of existing Line 3 would create a significant risk to other operating pipelines and additional impacts to the environment, land use, and public safety similar to and exceeding those related to constructing a new pipeline project. Based on the results of the risk assessment, Enbridge believes that deactivating a pipeline in place minimizes and/or eliminates unnecessary impacts to the environment, landowners, and the state of Minnesota..

This document describes the way in which Enbridge plans to Permanently Deactivate the existing Line 3 pipeline in the United States. This plan was designed to Permanently Deactivate the pipeline in a way that minimizes risks to public safety, the environment, and current land use. A brief summary of the Permanent Deactivation scope is as follows:

1. Purging the oil;
2. Cleaning of the pipeline;
3. Isolating the pipeline from specific infrastructure which is actively transporting oil;
4. Further segmentation of the pipeline, as needed, including completing all required remediation at roads, railroads, waterbodies, or any other permitted crossing in consultation and coordination with that crossing's authority; and
5. Continue to monitor the existing right-of-way (ROW) to identify, assess, and appropriately mitigate apparent or emerging risk to public safety, the environment, or current land use caused by the Permanently Deactivated pipeline. As part of the ongoing maintenance and monitoring, continue to apply cathodic protection (CP) until such time that it is ineffective or otherwise detrimental.

As discussed in this Plan, Enbridge's assessments identified the following risks are related to pipelines Permanently Deactivated in place:

- soil and water contamination;
- water conduits; and
- subsidence.

Enbridge analyzed these risks and developed mitigation plans, as necessary. Table 1-1 summarizes how Enbridge plans to minimize each of these risks on Line 3. Further details of these activities are presented in the body of this report.

Table 1-1: Summary of Risks and Mitigation

Hazard	Enbridge Analysis/Mitigation
Soil and Water Contamination	To prevent soil and water contamination, Enbridge will purge (i.e., remove) all crude oil from the pipeline and clean the pipe of remaining hydrocarbons. Based on the results of third party testing and validation, it is expected that the amount of hydrocarbons left in the pipe after cleaning would be de minimis. As a result, there will be no material risks to soil or water contamination from oil remaining in Line 3 after the line is purged and cleaned.
Water Conduits	Enbridge will segment the Permanently Deactivated pipeline to protect the water resources from the risk that the pipeline would act as a water conduit. The pipeline will be isolated at its 7 pump stations/terminals and further segmented at the 40 MLV locations which are located along Line 3 in Minnesota. Additional segmentation and/or grouting may be completed in consultation with the crossing authorities at roads, railroads, and other locations where public and environmental safety is a concern. Assessment of topography and existing water resources demonstrates that Enbridge's segmentation plan will prevent water from moving a material distance within the Permanently Deactivated pipeline.
Ground Subsidence	Enbridge conducted a series of assessments to predict the risk of ground subsidence over an extended time frame. Enbridge plans to continue applying cathodic protection (CP) to the Permanently Deactivated pipeline to address the risk of ground subsidence due to eventual pipeline collapse. With the application of CP, the first single points of through wall corrosion are not expected to occur for 25 to 50 years. Note that a single point of through wall corrosion would not cause the pipe to collapse. The structural integrity of the pipe is expected to remain intact for hundreds of years. Given these estimates, it is anticipated that the pipe will likely be filled with soil by the time it has corroded to a point of collapse, which will minimize subsidence. Further, Enbridge plans to continue to monitor the Permanently Deactivated Line 3 ROW, which is in the middle of a corridor of other operating pipelines. Additional grouting may be completed at roads and railroads after consultation with crossing authorities, in order to remove the risk of any subsidence at these locations. This ROW monitoring program will inspect for any signs of subsidence on the ROW and develop plans to address the issue if it arises.

2 GUIDING INDUSTRY REGULATIONS AND LITERATURE

While Enbridge has used the term "Permanently Deactivated" to refer to taking the existing Line 3 out of service permanently, industry terminology generally refers to pipeline "abandonment" rather than "Permanent Deactivation," and the references and citations that follow use the terminology accordingly. Enbridge has relied on this literature because, from a physical perspective, the activities associated with abandonment and deactivation are the same.

2.1 Federal

Line 3 is an interstate pipeline. As such, its operations are regulated by PHMSA under Title 49 of the CFR. Enbridge will comply with all applicable federal requirements within Title 49 of the CFR or those requirements included by reference. Additionally, Enbridge will follow the code guidance published by the ASME.

- **49 CFR § 195.59** – "For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility."

- **PHMSA's NPMS Submission Guide** – "6I. Newly Abandoned Pipelines. Pipelines that were newly abandoned during the last calendar year should be included in your new NPMS data submission."

- **PHMSA – 195.64** – "§ 195.64 National Registry of Pipeline and LNG Operators. (a) OPID Request. Effective January 1, 2012, each operator of a hazardous liquid pipeline or pipeline facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID or a change to an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline and LNG Operators in accordance with §195.58….(c) Changes. Each operator must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at http://opsweb.phmsa.dot.gov, of certain events. (1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs: (i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable."

- **49 CFR § 195.402** – "(a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. (c) Maintenance and normal operations. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations: “(10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through commercially navigable waterways the last operator of that facility must file a report upon abandonment of that facility in accordance with § 195.59 of this part.”(13) Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.”

- **PHMSA – 645.211** - “The FHWA [U.S. Department of Transportation’s Federal Highway Administration]> should use the current editions of the AASHTO [American Association of State Highway and Transportation Officials] publications, “A Guide for Accommodating Utilities Within Highway Right-of-Way” and “Roadside Design Guide” to assist in the evaluation of adequacy of STD utility accommodation policies….(a) Utilities must be accommodated and maintained in a manner which will not impair the highway or adversely affect highway or traffic safety. Uniform procedures controlling the manner, nature and extent of such utility use shall be established.”

- **PHMSA’s Operations & Maintenance Enforcement Guidance, Part 195 Subpart F** – “Only abandoned (permanently removed from service) pipelines are exempt from Part 195 regulations with exception of abandonment inventory reporting requirements….. Inactive pipeline, which may or may not contain liquids, must meet all applicable requirements of Part 195. Operators sometimes do not completely abandon a pipeline and may sometimes use terms such as “idle”, “inactive”, or “out of service” to describe this situation. The regulations do not define “idle” or “inactive” pipe. Pipe is either considered active or abandoned. If a pipeline has not been abandoned according to the guidance, then it is active and the operator must ensure that the pipeline complies with all requirements of Part 195.”

- **The American Association of State Highway and Transportation Officials** (AASHTO) – A Guide on the Accommodation of Utilities Within Freeway Right-of-Way, – “Untrenched Construction - Methods may include directional drilling, micro tunneling, driving, coring, or boring….Grout backfill should be considered for carriers or casings more than 300 mm (12 in.) in diameter and for overbreaks, unused holes, or abandoned carriers or casings. Untrenched excavations 100 mm (4 in.) or less in diameter may be exempt from void filling requirements in accordance with the transportation agency's utility accommodation policy.”

- **American Society of Mechanical Engineers (ASME) B31.4-2012** – 457 ABANDONING A PIPING SYSTEM – “In the event of abandoning a piping system, it is required that (a) facilities to be abandoned in place shall be disconnected from all sources of the transported liquid, such as other pipelines, meter stations, control lines, and other appurtenances; (b) facilities to be abandoned in place shall be purged of the transported liquid and vapor with an inert material and the ends sealed.”

- **PHMSA Advisory Bulletin – Pipeline Safety: Clarification of Terms Relating to Pipeline Operational Status –** "SUMMARY: PHMSA is issuing this advisory bulletin to all owners and operators (operators) of hazardous liquid, carbon dioxide, and gas pipelines, as defined in 49 Code of Federal Regulations Parts 192 and 195, to clarify the regulatory requirements that may vary depending on the operational status of a pipeline. Further, this advisory bulletin identifies regulatory requirements operators must follow for the abandonment of pipelines. Pipeline owners and operators should verify their operations and procedures align with the regulatory intent of defined terms as described under this bulletin. Congress recognized the need for this clarification in its Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016."

2.2 Enbridge Standards

Enbridge has developed an internal standard titled "D06-201 – Pipeline and Facility Change in Operational Status" to ensure compliance with the applicable standards. This internal standard recommends the completion of several analyses, including:

- project-specific risk assessment;
- land use assessment;
- crossing assessment;
- depth of cover assessment;
- erosion and slope stability assessment;
- long-term monitoring and mitigation assessment;
- ground subsidence and soil mechanics/pipeline collapse assessment;
- environmental contaminant considerations assessments;
- coatings contamination assessment; and
- NORM and PCB review.

In addition to the aforementioned analyses, the standard provides guidance on:

- criteria for draining product from existing mainline and facilities;
- methods of purging product from the system;
- methods of cleaning pipeline and facilities; and
- methods to isolate the pipeline from operating infrastructure.

Enbridge has adhered to this internal standard in order to ensure the safest and most efficient practice when deactivating Line 3.

2.3 PIPELINE ABANDONMENT MATRIX

The Canadian Energy Pipeline Association (CEPA) developed a Pipeline Abandonment Matrix to provide general guidance for a company who has to decide whether to abandon a pipeline by removing it or abandoning it in place. The Pipeline Abandonment Matrix looks at both the diameter of the pipeline and existing and potential future land use considerations which are then broken down into usage categories. A summary of the Pipeline Abandonment Matrix for pipe diameters greater than 26 inches is provided in Table 2-1 below.

Table 2-1: CEPA Pipeline Abandonment Matrix

Land Use		Primary Option For Abandonment (Pipe Diameter > 26")
Agricultural	Cultivated	Abandon In Place
	Cultivated with special features* (depth of cover considerations)	Remove
	Non Cultivated (Native Prairie, Rangeland, Pasture)	Abandon In Place
Non-Agricultural	Existing Developed Lands (Commercial, Industrial, Residential)	Abandon In Place
	Prospective future development (Commercial, Industrial, Residential)	Remove
	No future development anticipated (e.g., Forest Areas)	Abandon In Place
Other Areas	Environmentally Sensitive Areas (including Wetlands)	Abandon In Place
	Roads & Railways	Abandon In Place (with special treatment to prevent potential ground subsidence)
	Water Crossings	Abandon In Place
	Other Crossings (Utilities)	Abandon In Place (with special treatment to prevent potential ground subsidence)

In the CEPA Pipeline Abandonment Matrix, there are only two land use situations in which removal is the recommended method to abandon a pipeline: (1) where the land is cultivated but has special features such as depth of cover considerations; or (2) when it is non-agricultural land and there is prospective future development contemplated. Neither of these two land use situations applies to Line 3 because it exists in a multi-pipeline corridor that contains active pipelines. In all other categories of land use, abandon in place is the recommended method to abandon a pipeline. Enbridge is proposing to Permanently Deactivate the existing Line 3 in place, and Enbridge's decision to deactivate in place is consistent with CEPA's recommendations.

3 RISK ASSESSMENT

Enbridge conducted a risk assessment to determine the technical risks associated with both removing the Line 3 from the ground and Permanently Deactivating Line 3 in place. As part of the assessment, Enbridge consulted with internal stakeholders, worked with external consultants to perform studies, and performed a literature review of industry studies. The risk assessment consisted of:

- collecting risk data during a risk identification workshop attended by representatives from Enbridge's various functional groups and subject matter experts;
- developing risk reduction and mitigation strategies for high risk scenarios; and
- committing to re-assessing the high risks (post-action) to assess the value of the reduction and mitigation strategies.

3.1 RISKS ASSOCIATED WITH PIPE REMOVAL

Pipeline removal would create impacts to the environment, land use, and public safety similar to a new pipeline project. Environmental hazards associated with pipe removal are related to the disturbance of the soil, potential impacts to the groundwater, and potential impacts to human activities, natural wildlife and vegetation. Reduced soil stability during and after excavation can also be a concern, as it can lead to increased localized erosion and destabilized slopes. These hazards may cause considerable disruption to ongoing and future land management activities. These risks increase significantly during a large scale removal project.

Excavation of the Permanently Deactivated Line 3 will cause significant disruption to landowners and the general public. Construction activities would restrict access to the ROW and adjacent works areas. Removal operations at crossings would not only cause traffic interruptions and restrictions, but soil stability issues caused by pipe removal could damage the roads, bridges and crossings. These issues introduce risk to existing infrastructure such as roadways, railways, and other utilities.

One of the greatest risks of removing a Permanently Deactivated pipeline is the risk of damaging adjacent pipelines or infrastructure, which can lead to significant public, environment, and operational impacts. The existing Line 3 currently shares a congested ROW with either five or six additional pipelines. Line 3 is located in the third position in roughly 75% of the mainline ROW corridor in Minnesota. In the U.S., the majority of Line 3 is within 7 to 18 feet edge-to-edge from the nearest adjacent, active pipeline. Given the proximity of Line 3 to other operating pipelines, removal increases the chance of a release from adjacent operational lines caused by either a line strike or by their fatigue due to the use of heavy equipment during removal activities.

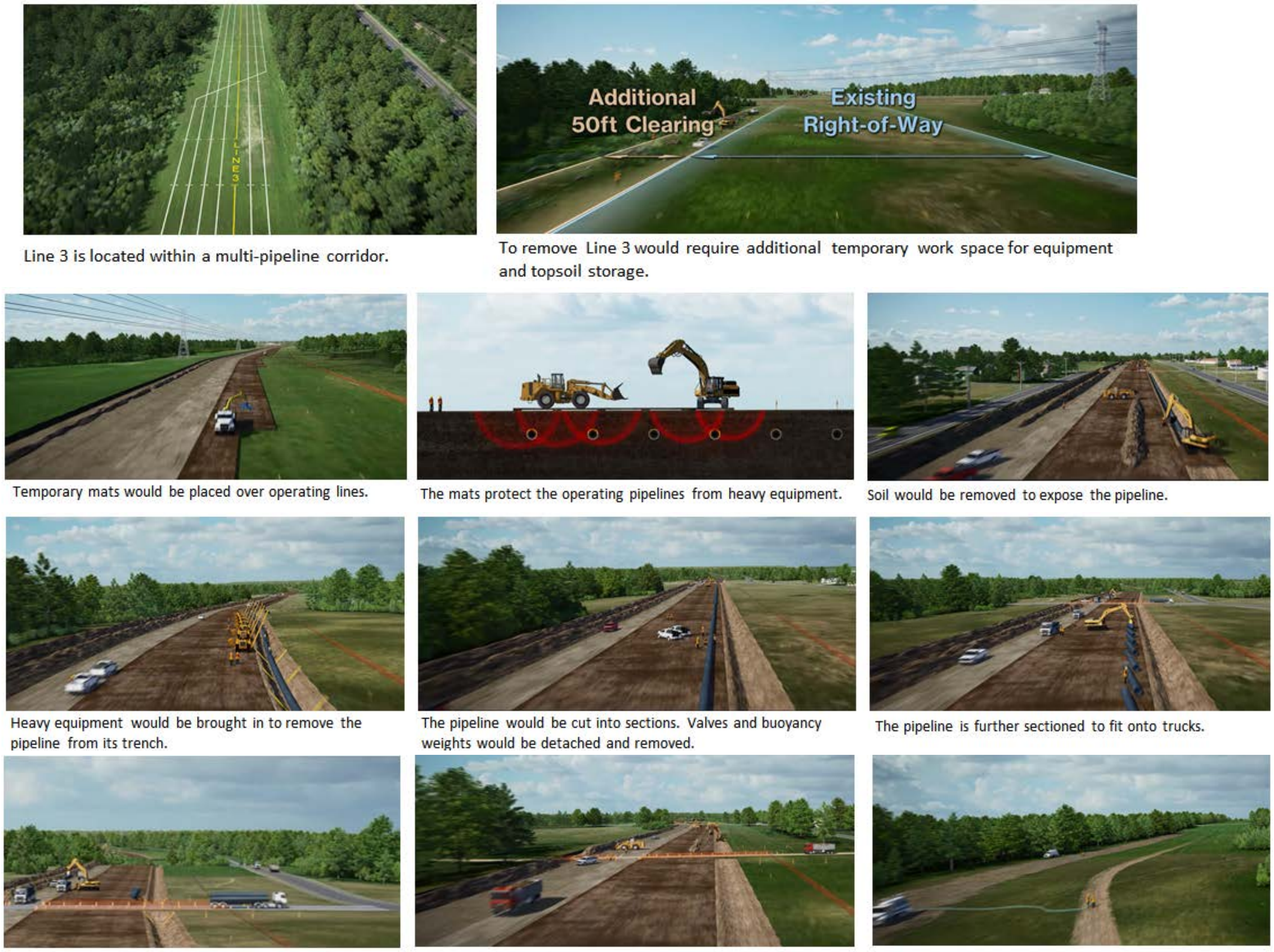
In light of the significant construction-related risks, execution in the congested corridor would also be a significant challenge, especially as it relates to excavation. Unlike the installation of a new pipeline (i.e., a pipeline installed as the outside pipe in a multi-pipe corridor), where crews can work over areas where there aren't active pipes underneath, the removal of a pipeline within a multi-pipe corridor necessitates the placement of timber mats over the active pipelines. The placement of these mats creates a working and travelling surface for large equipment to use when excavating and pulling out the abandoned pipe. Enbridge estimates approximately 600,000 – 900,000 mats would be required to safely remove Line 3 from the ground. Securing this volume of mats at one time may not be feasible.

Additionally, in areas where pipelines are relatively close to each other or where there exists slope stability concerns due to either changes of ground elevation across the ROW or wet soil conditions, the installation of sheet piling may be required. Sheet piling will likely be required in all saturated wetlands. Removal of Line 3 would require over 235,000 tons of steel to sheet pile both sides of the pipe located in saturated wetlands along the ROW. Similar to mats, securing this volume of sheet piling at one time may not be feasible.

Due to restrictions on utilization machines to excavate within close proximity of active pipelines (minimum of 1 foot of clearance), Enbridge would likely use either hand dig or hydraulic vacuums to excavate the Permanently Deactivated Line 3 in order to meet Enbridge's Ground Disturbance Guideline (MP-HSMS-009) to reduce the likelihood of construction damage to existing infrastructure. Hydraulic vacuum excavation could present a challenge due to the large amount of water and associated slurry waste needed due to the size of the removal project. Enbridge estimates approximately 1.7 million gallons of slurry waste would be produced if the pipe were to be removed from the trench. This will also create disposal and erosion challenges. Notwithstanding Enbridge's robust construction specifications, proper planning and execution, the likelihood of a mechanical incident will be elevated due to the size of the removal project, irrespective of the party conducting the excavation.

In areas where the abandoned pipe is both (a) on the interior of a multi-pipeline corridor and (b) within a saturated wetland, mats and sheet piling will not provide the protections they would normally offer in a dry area based upon the lack of bearing capacity of the saturated wetland's soil. This lack of bearing capacity introduces the potential for the placed matting to *sink* when it is driven over by heavy equipment. This sinking could progress all the way unit the mats are resting upon those very same pipes they were once trying to protect. Again, because of the lack of bearing pressure, even when considering relatively long sheet piling, there exists risk that driven sheet pile will not "reach bottom" and, as such, will not serve as adequate soil stability or as the "foundation" for a temporary matting road and would prevent access to those areas. Due to the access issues identified in saturated wetlands, Enbridge anticipates there will be areas where pipe removal cannot be safely performed. Please see Figure 3-1 which shows the stages of pipeline removal.

Figure 3-1: Stages of Pipeline Removal



Line 3 is located within a multi-pipeline corridor.

To remove Line 3 would require additional temporary work space for equipment and topsoil storage.

Temporary mats would be placed over operating lines.

The mats protect the operating pipelines from heavy equipment.

Soil would be removed to expose the pipeline.

Heavy equipment would be brought in to remove the pipeline from its trench.

The pipeline would be cut into sections. Valves and buoyancy weights would be detached and removed.

The pipeline is further sectioned to fit onto trucks.

The pipeline sections would be hauled away by truck.

Additional trucks would bring in soil to fill the void from the removed pipeline.

The right-of-way would be restored.

3.2 RISKS ASSOCIATED WITH DEACTIVATING A PIPE IN PLACE

Permanently Deactivating Line 3 in place avoids the potential risks and impacts related to ground disturbance and active pipelines discussed for removal. Nonetheless, there are other risks related to abandoning a pipeline in place that need to be addressed. To further assess these risks, Enbridge reviewed industry literature related to the deactivation or abandonment of pipelines, including: CSA Z662[4], the 2007 CEPA Report[1], and the 2010 DNV GL Study[6]. The literature review identified that the following areas are the most critical to address for Permanently Deactivated pipelines:

- Soil and water contamination;
- Water conduits; and
- Subsidence.

As summarized in Table 1-1, Enbridge has studied each of these risks and determined a mitigation strategy to minimize each one. Each identified risk, Enbridge's engineering analyses, and mitigation strategies, is described in detail in the following sections of this Plan.

3.3 RECOMMENDED APPROACH

Based on the results of the risk assessment, Enbridge believes that deactivating a pipeline in place minimizes and/or eliminates unnecessary impacts to the environment, landowners, and the state of Minnesota. Removing the 282 miles of existing Line 3 would create a significant risk to other operating pipelines and additional impacts to the environment, land use, and public safety similar to and exceeding those related to constructing a new pipeline project. Permanently Deactivating Line 3 in place poses some risk of water and soil contamination, water conduit, and ground subsidence. However, based on Enbridge's engineering assessments, these risks can be adequately avoided, minimized, or mitigated through the cleaning program, isolation and segmentation, and ongoing monitoring and maintenance activities as described in this Plan.

It is unnecessary, therefore, to subject the environment, landowners, and the state of Minnesota to the additional removal impacts and risks when deactivating a pipeline in place can be done in a manner that minimizes known risks. Accordingly, deactivation in place is recommended for the following land uses because the disturbance caused by pipe removal would likely adversely affect landowners, sensitive areas or existing infrastructure:

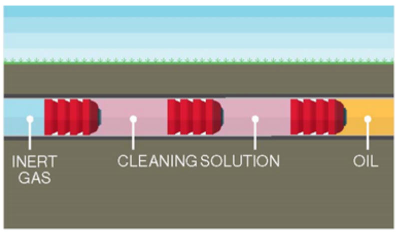
- environmentally sensitive areas (parks, wetlands, natural areas, species at risk habitat);
- water crossings (streams, rivers, lakes, canals);
- non-agricultural lands;
- forested lands;
- existing developed lands (commercial, industrial, residential);
- non-cultivated lands (native prairie, range land);
- roads and railways;
- other crossings (utilities, other pipelines); and
- cultivated (including those that are irrigated).

The remainder of this Permanent Deactivation Plan discusses minimize risks and impacts related to the pipeline remaining in the ground.

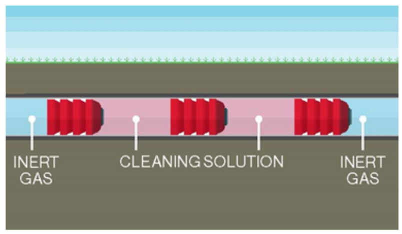
4 SCOPE OF WORK FOR DEACTIVATING IN PLACE

The Line 3 Permanent Deactivation Plan will comply with applicable regulations for abandoned pipelines and include execution of measures designed to minimize the risk of soil and water contamination, water conduits, and ground subsidence. The Permanent Deactivation Plan will follow the five main steps which are summarized in Figure 4-1 below.

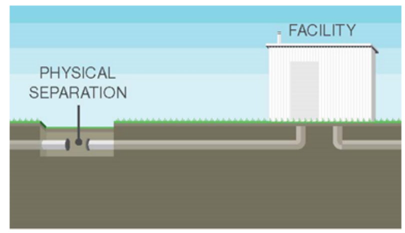
Figure 4-1: Deactivation Process



Purging: The pipeline is purged of oil product using an inert gas.



Cleaning: A combination of cleaning tools and cleaning solutions are used to wipe and clean the pipeline.



Isolation: The pipeline is physically disconnected and sealed off from the active operational facilities.

Segmentation: Further isolation may be employed where necessary by closing of pipeline valves or other means, including cutting and sealing.

Monitoring and Maintenance: The pipeline will continue to be monitored with regular pipeline patrols, signs indicating location, depth of cover surveys and inclusion in "Call Before You Dig" programs.

4.1 MINIMIZING THE RISK OF SOIL AND WATER CONTAMINATION

4.1.1 Soil and Water Contamination Risk

One identified risk is that soil and water contamination could occur from hydrocarbons remaining in the pipeline after it is removed from service. In order to minimize this risk, Enbridge will purge the pipeline of crude oil and implement a cleaning program to remove remaining hydrocarbons from the pipeline.

4.1.2 Mitigation

4.1.2.1 Purging

Existing product within the pipe will be purged, or pushed through the pipeline, using pigs propelled with nitrogen gas. Enbridge will deactivate the existing Line 3 between MP 789 near Joliette, ND and MP 1098 near Superior, WI. Deactivation will proceed in two sections:

Section one will consist of a pipeline purge between the Gretna Station (MP 772) and the Clearbrook Terminal (MP 909) followed by pipeline cleaning and disconnecting the pipeline from the facilities along the Gretna to Clearbrook segment and at Clearbrook Terminal. See Figure 4-2.

Section two will consist of a pipeline purge, pipeline cleaning, and disconnecting the pipeline from the facilities at Clearbrook Terminal (MP 909) and along the pipeline to the Superior Terminal (MP 1097). See Figure 4-3.

Figure 4-2: Purge Diagram (Gretna to Clearbrook)

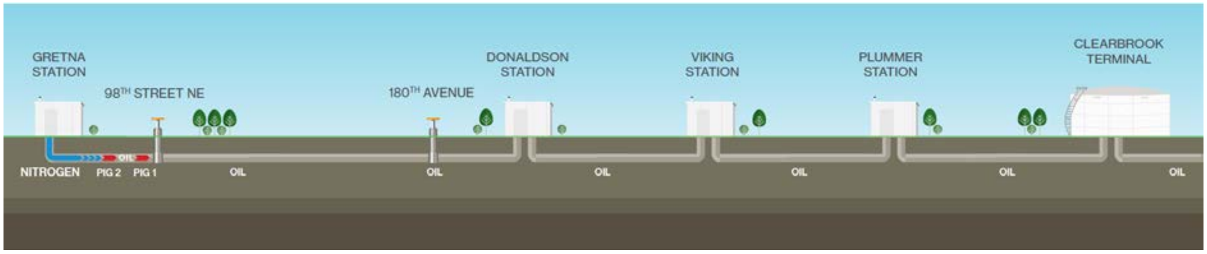
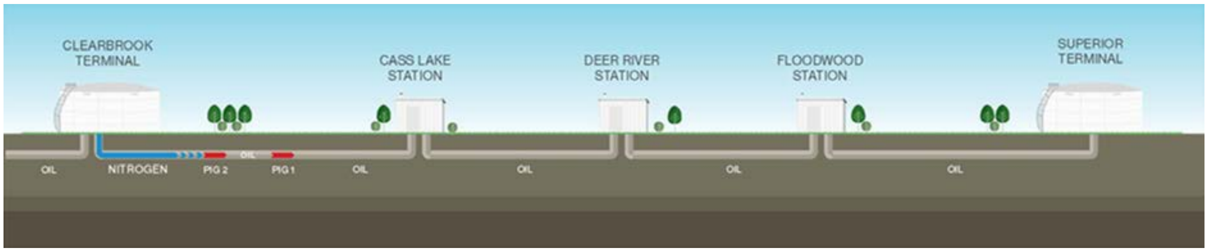


Figure 4-3: Purge Diagram (Clearbrook to Superior)



For each section, a batch of two (2) 34” pigs will be loaded and launched. The first pig will be a purge pig followed by a batch of oil and a tailing purge pig. Nitrogen injected at the beginning of the section is used to propel the pigs to the downstream side of the nearest intermediate station. This will “push” the oil along the pipeline. The purge operation will continue by injecting nitrogen at each of the intermediate stations until the pigs reach the end of the section; the Clearbrook Terminal (MP 909) or Superior Terminal (MP 1097), respectively. The oil that has been pushed to the terminus of the pipeline (i.e., purged oil) will be delivered to tankage at either the Clearbrook Terminal for section 1 or the Superior Terminal for section 2. All purging activities will be undertaken subject to any federal, state or local permitting requirements.

Once the purging operation is complete, the section of Line 3 will be prepared for cleaning.

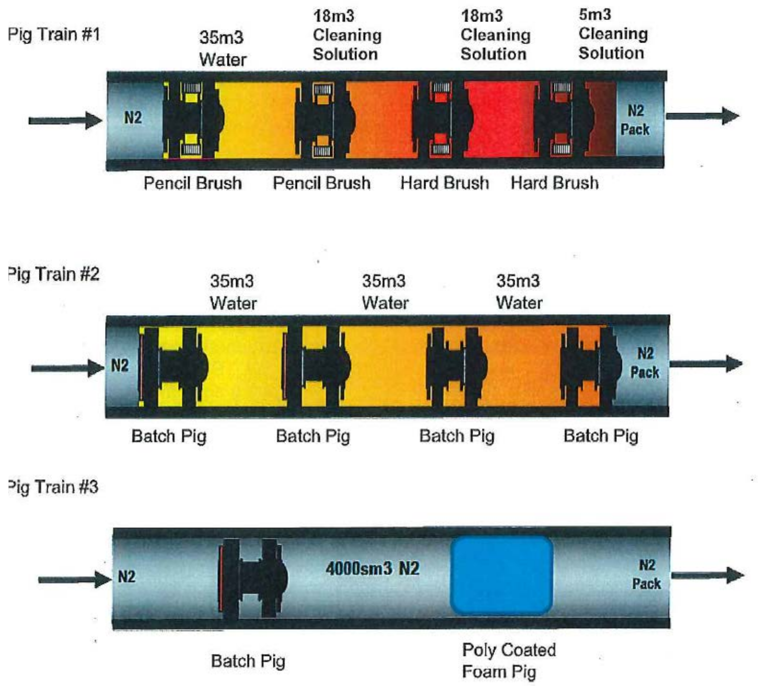
4.1.2.2 Cleaning

In order to minimize soil and water contamination risks, the existing Line 3 pipeline will be cleaned with the appropriate solvents to remove hydrocarbons from the pipe walls. The appropriate solvent is typically an engineered cleaning solution comprised of water and/or water and biodegradable cleaning agents. After purging is complete, cleaning runs will be completed in a sequence similar to that shown in Figure 4-4.

The cleaning program will be verified when Enbridge completes cleaning the first section and re-verified during cleaning of each subsequent section. Each cleaning stage will be sampled to confirm cleanliness.

All cleaning activities will be undertaken subject to any applicable federal, state or local permit requirements. All solid waste materials generated as a result of cleaning activities will be handled and disposed of in accordance with applicable federal and/or state requirements. All of the cleaning solution used during this process will be appropriated and disposed of in accordance with permit requirements.

Figure 4-4: Example Cleaning Sequence



Enbridge completed a two-phase verification to validate its proposed cleaning program (Appendix 7.1). The first phase consisted of laboratory testing of representative pipeline material, which determined the appropriate chemical selection for the cleaning material, as well as hydraulic modeling and cleaning train design. In the second phase, this cleaning program was then applied to a 12-mile deactivated section of Line 3 pipe after it was taken out of service in 2014. All fluid samples collected during the cleaning process were submitted to an accredited laboratory for unbiased and independent chemical analysis of the samples taken. The laboratory analysis concluded that PCB and NORM concentrations were below detectable limits and, therefore, the Permanently Deactivated pipe did not pose a risk of contamination. Scientific analysis of the rinse water concluded that 99.9999987% of the product was removed from the pipeline after the cleaning regime was completed. If the results of this 12-mile section were extrapolated to the results expected from cleaning the entire 282 miles of Line 3 in Minnesota, this is equivalent to less than one gallon of hydrocarbons that would be left inside the pipeline. Therefore, the cleaned pipe would not pose a risk of contamination.

As mandated by the Department of Justice Consent Decree, cleaning and purging of the existing Line 3 must begin within three months of the in-service date (ISD) for the Line 3 Replacement Project.

4.2 Minimizing the Risk of Water Conduit Effect

4.2.1 Water Conduit Risk

A Permanently Deactivated pipeline may function as a conduit to transport water or soil in a downslope direction if the pipeline has significantly degraded after being Permanently Deactivated. Pipeline corrosion and/or third party damage (e.g., a line strike which may affect coating quality and, in turn, accelerate localized corrosion) are the most likely events that cause the pipe to degrade over time. If the structural integrity of the pipeline is compromised, water and surrounding materials may infiltrate the pipe and have the potential of travelling downslope and exiting the pipe at another location. Water conduits may cause water migration to or from sensitive environmental features such as wetlands, watercourses, water supply areas such as aquifers, areas with sodic/saline or sandy soils, agricultural lands, and areas with a high water table.

Each of the following conditions is necessary for the formation of water conduits:

- Through-wall corrosion to allow water to enter the pipeline;
- The Permanently Deactivated pipeline must be in contact with water (that is, the pipeline is located at or below the water table);
- The portion of the pipeline that forms the conduit must be intact;
- There must be a preferential exit corrosion point that allows water to exit following movement within the pipeline;
- There must be sufficient elevation changes between the entry and exit points to allow for the movement of water; and
- The influx of soil must be of such type and occur in such a fashion that it does not effectively block the conduit.

The creation of water conduits along the outside of pipelines has not been identified as a risk. It is industry standard during pipeline construction and restoration that trench breakers are placed to prevent this occurrence, and it is assumed that given the vintage of Line 3, the likelihood of an external conduit occurring is minimal as the pipeline has been through numerous freeze/thaw cycles over its lifetime. In addition, the Permanently Deactivated pipeline will be monitored as part of the Enbridge Operations and Maintenance Manual, and if evidence of water conduit formation along the outside of the Permanently Deactivated pipeline is observed, similar mitigation measures to those used for operating pipelines will be implemented.

The key mitigation measures identified to reduce the potential effects of the formation of water conduits are:

- pipeline cleanliness (to address potential contamination from within the pipeline);
- isolation and pipeline segmentation;
- responding to one call requests for the Permanently Deactivated line;
- monitoring of the ROW; and
- maintaining CP.

Enbridge's planned cleaning program is described in Section 4.1.2.2. Enbridge's planned continued monitoring and maintenance, including One-call participation, are discussed in Section 4.3.2. The following section focuses on Enbridge's assessment and plans to isolate and segment existing Line 3.

4.2.2 Segmentation Assessments

Segmentation is conducted to avoid the potential for the Permanently Deactivated pipeline to act as a water conduit. To ensure protection of resources such as wetlands, streams and rivers, a detailed analysis has been completed to show the effectiveness of segmentation of the Permanently Deactivated pipeline at predetermined locations, including pump station and MLV locations. In addition to these existing segmentation locations, topography, hydrology and depth of cover have been reviewed in detail and taken into consideration in order to identify additional segmentation locations.

Enbridge conducted several segmentation assessments to identify segmentation locations for the Permanently Deactivated Line 3 pipeline and to mitigate the risk of water conduit via the pipeline. The following analyses were completed:

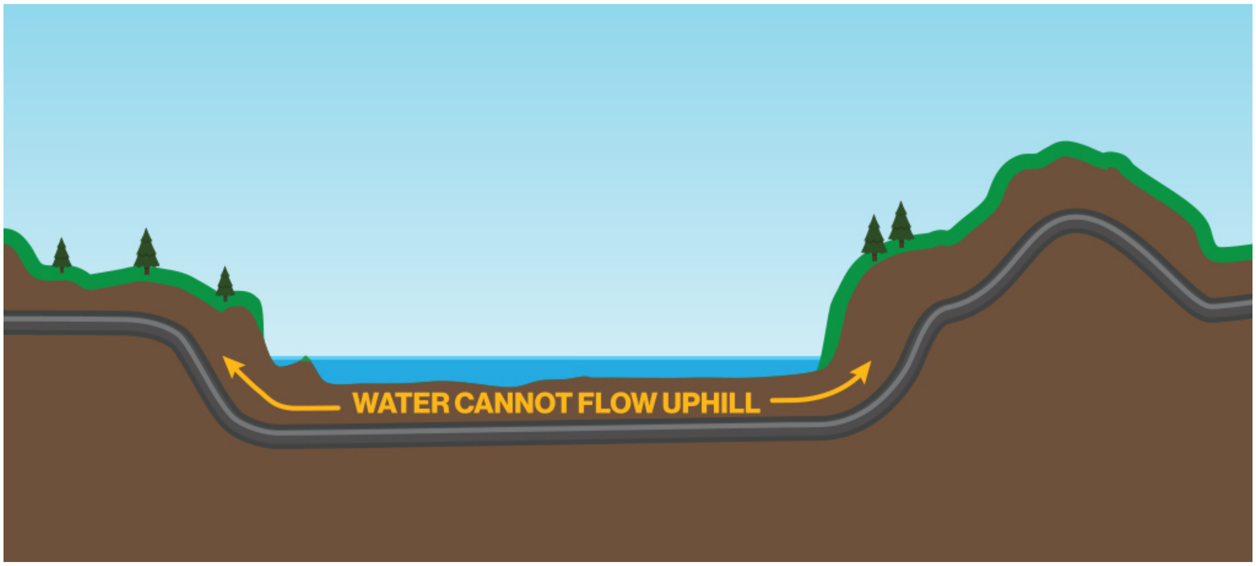
1. Desktop review of Enbridge data collected through years of operational history, including, but not limited to: wetland and waterbody delineations, cultural surveys, pipe depth of cover, ground profile information, and valve and station locations;
2. Desktop review of publicly available data including: water table elevation, soil types and ground profile information;
3. Computer-assisted iterative model to verify and confirm the results of the in-depth desktop analysis;

4. Using the results of the desktop analysis and computer model, provide a detailed listing of segmentation locations; and
5. Provide implementation strategy for in-field segmentation locations to ensure protection of all identified features, on a site-specific basis.

4.2.2.1 Topographical High Concept

The Topographical High Concept is an approach used to identify where the existing topography of the land acts as a physical barrier to the movement of water through a Permanently Deactivated pipeline. To accommodate local accumulation of seepage water at sag, or low points, a topographical high must be greater than one pipeline diameter above any adjacent lows. The Topographical High Concept was used to identify areas along the Line 3 pipeline that will act to hydraulically disconnect the pipeline and mitigate the water conduit effect. See Figure 4-5 for a representation of the Topographical High Concept.

Figure 4-5: Topographical High Concept



For the purpose of the Topographical High Concept used in the segmentation modeling, a topographical high is defined by:

A location along a pipeline that has an elevation sufficiently above:

- The predicted groundwater elevation, based on known ground surface elevations and regional characteristics, and
- The water level on both sides of a surface water or delineated wetland/waterbody feature that provides sufficient topographical relief to hydraulically isolate adjacent features or other upstream and downstream features outside a natural hydraulic connection. In addition to hydraulic disconnection, and in order to accommodate local

accumulation of fluid at sag points, a topographic high must also be a distance greater than one pipeline diameter (here, 34 inches) above any adjacent lows.

This definition will be used to identify areas along the existing Line 3 pipeline where the surface topography acts to hydraulically disconnect the pipeline and effectively mitigate the water conduit effect. To be effective, the topographic high must ensure that hydraulic disconnection is maintained in one or both directions from the topographic high to the next adjoining segmentation point in perpetuity. To prevent the pipeline from acting as a conduit, the elevation of the topographic high must be greater than the estimated highest annual surface/groundwater level.

The distance over which a topographical high will be applicable as an alternative to other segmentation methods will depend on factors such as hydrological and hydrostatic conditions, pipeline elevation, topography, local water accumulation, outflow zones, and both the distance to, and the elevation of, the next adjoining segmentation point specific to the lateral section of the pipeline being considered.

4.2.2.2 SEGMENTATION MODELING METHODS

4.2.2.2.1 Desktop Analysis

Using publicly available and additional Enbridge captured ground and pipeline profile data, a desktop analysis was performed to holistically review potential flow paths caused by elevation differences between known and delineated wetlands/waterbodies and ground water levels using the Topographical High Concept.

In many cases the wetlands and water bodies were found to be at naturally occurring local low points in the topography. In such cases, the pipe elevation coming into and exiting such features is greater than the elevation of the feature itself. This effectively eliminates the susceptibility for water to migrate out of the identified feature to any other feature. In addition to this naturally occurring segmentation, each delineated wetland was reviewed to determine if it is part of a larger wetland complex and/or combined wetland and stream/river crossing in order to identify locations of hydraulic connectivity and limit any potential exposure outside of the confines of the same complex.

Similar to the analysis performed for each individual wetland and waterbody feature, publicly available data in combination with field data obtained during the construction of Line 67 (Alberta Clipper) in 2009/2010 was used to analyze the possibility of a flow path within the water table that could create a water conduit risk.

4.2.2.2.2 Computer Assisted Model

To support the detailed desktop analysis, a segmentation model was developed using an iterative process to assess the potential effects of the water conduit effect. The model considers the topography of the land, the depth of cover of the pipeline, the location of wetlands/waterbodies, and current proposed isolation/segmentation locations (that is, manual and automatic valves and facilities), and the groundwater elevation. The model uses an iterative process to determine and verify the results of the desktop analysis by doing a query that looks both upstream and downstream of known features to find the topographical high, and reports such areas that need to be investigated for potential segmentation points, if other factors do not mitigate such risk.

Data for topography, and the groundwater elevation was obtained from publically available sources. Isolation and segmentation locations (MLVs, stations and terminals) and pipeline depth-of-cover were obtained from Enbridge. In order to determine where additional segmentation of the pipeline is recommended, the segmentation model uses water table evaluation data, surface elevation data, pipeline elevation data, the location of existing isolation and segmentation points, and an iterative computer analysis. The segmentation model considers the regional movement of water when determining the placement of segmentation locations.

4.2.2.3 Refinement of the Segmentation Model Results

The model results were reviewed to determine whether or not the segmentation locations were optimally placed to mitigate the water conduit effect while reducing the amount of environmental disturbance associated with segmentation activities to the greatest extent practicable. As part of the desktop and iterative computer model reviews, all known features were given the same consideration for protection from a water conduit path.

4.2.2.4 Results and Recommended Segmentation Assessments

Based on the engineering assessment completed, 47 locations have been identified in the state of Minnesota for isolation (see Table 4-1). These 47 locations consist of the 40 mainline valves, 6 pump stations, and one co-located pump station/terminal within MN. There are three additional locations that have been identified as potential segmentation locations (items 8, 10 and 12 in Table 4-1) due to elevation changes and waterbody characteristics; these locations are currently being analyzed based on site specific factors (e.g., soil characteristics, topography, and hydraulic connectivity) and will be used as segmentation locations if determined that the water conduit effect poses a risk. Additionally, final isolation locations are subject to further refinement based upon the completion of the field assessment and detailed engineering and constructability review.

Table 4-1: Segmentation and Isolation Locations

Existing Line 3 Segmentation/Isolation Locations				
Number	ROW MP	Elevation (ft.)	Location	Action
1	803.25	792	MLV 803.25-3-V	Segment
2	805.55	795	MLV 805.55-3-MOV	Segment
3	814.01	820	MLV 814.01-3-V (Donaldson)	Station Isolation
	814.02	820	CHK 814.02-3-V (Donaldson)	
	814.11	820	MLV 814.11-3-MOV (Donaldson)	
4	829.16	877	MLV 829.16-3-V	Segment
5	834.51	929	MLV 834.51-3-V	Segment
6	838.36	964	MLV 838.36-3-V	Segment
7	840.77	984	MLV 840.77-3-V	Segment
8	844-848			Site Specific Analysis Underway
9	848.15	1049	MLV 848.15-3-MOV (Viking)	Station Isolation
10	850-854			Site Specific Analysis Underway
11	857.14	1133	MLV 857.14-3-V	Segment
12	860-864			Site Specific Analysis Underway
13	864.02	1100	MLV 864.02-3-MOV	Segment
14	865.06	1102	MLV 865.06-3-MOV	Segment
15	867.40	1101	MLV 867.40-3-V	Segment
16	873.43	1116	MLV 873.43-3-V	Segment
17	876.99	1142	MLV 876.99-3-MOV (Plummer)	Station Isolation
	877.05	1142	CHK 877.05-3-V (Plummer)	
18	885.65	1141	MLV 885.65-3-V	Segment
19	895.96	1240	MLV 895.96-3-V	Segment
20	899.31	1335	MLV 899.31-3-V	Segment
21	904.56	1292	MLV 904.56-3-V	Segment
22	909.15	1351	MLV 909.15-3-MOV (Clearbrook)	Terminal/Station Isolation
	909.17	1351	MLV 909.17-3-MOV (Clearbrook)	
	909.39	1351	MLV 909.39-3-MOV (Clearbrook)	
	909.43	1351	MLV 909.43-3-MOV (Clearbrook)	
23	916.52	1440	MLV 916.52-3-V	Segment

24	933.43	1383	MLV 933.43-3-V	Segment
25	939.45	1365	MLV 939.45-3-MOV	Segment
27	940.02	1362	MLV 940.02-3-MOV	Segment
27	943.69	1365	MLV 943.69-3-V	Segment
28	949.90	1358	MLV 949.90-3-V	Segment
29	953.02	1337	MLV 953.02-3-MOV (Cass Lake)	Station Isolation
	953.02	1337	CHK 953.02-3-V (Cass Lake)	
30	955.05	1312	MLV 955.05-3-V	Segment
31	957.91	1320	MLV 957.91-3-MOV	Segment
32	972.74	1314	MLV 972.74-3-V	Segment
33	973.70	1320	MLV 973.70-3-MOV	Segment
34	985.66	1307	MLV 985.66-3-MOV	Segment
35	986.40	1304	MLV 986.40-3-MOV	Segment
36	987.75	1293	MLV 987.75-3-V	Segment
37	989.71	1291	MLV 989.71-3-V	Segment
38	995.92	1292	MLV 995.92-3-V (Deer River)	Station Isolation
	996.03	1292	MLV 996.03-3-MOV (Deer River)	
39	1007.32	1327	MLV 1007.32-3-V	Segment
40	1010.57	1288	MLV 1010.57-3-MOV	Segment
41	1011.66	1292	MLV 1011.66-3-MOV	Segment
42	1017.99	1307	MLV 1017.99-3-MOV	Segment
43	1019.87	1302	MLV 1019.87-3-V	Segment
44	1025.85	1315	MLV 1025.85-3-V	Segment
45	1044.36	1253	MLV 1044.36-3-MOV (Floodwood)	Station Isolation
	1044.36	1253	CHK 1044.36-3-V (Floodwood)	
46	1046.94	1270	MLV 1046.94-3-V	Segment
47	1060.10	1320	MLV 1060.10-3-V	Segment
48	1062.51	1347	MLV 1062.51-3-V	Segment
49	1073.41	1212	MLV 1073.41-3-MOV	Segment
50	1079.91	1051	MLV 1079.91-3-MOV	Segment

4.2.3 Mitigation

To minimize the potential risk for existing Line 3 to act as a water conduit, Enbridge will isolate and segment the pipeline as described in this Plan.

4.2.3.1 Pipeline Isolation

In accordance with CFR Part 195, the Permanently Deactivated pipeline will be physically separated (or isolated) from in-service piping to prevent the reintroduction of oil into the pipeline. Additionally, equipment and instrumentation on the pipeline, with the exception of CP, will be disconnected from electrical sources. All applicable federal, state and local permitting approvals will be obtained prior to undertaking any pipeline isolation activities.

The following sections provide additional details regarding the activities undertaken to isolate Line 3 from other pipelines, pump stations, terminal, MLVs and other facilities.

4.2.3.1.1 Pump Stations and Terminals

The pipeline will be physically disconnected and isolated from pump stations and terminals by safely excavating down to the isolation location, mechanically cutting the pipeline, removing a small section of pipe, and welding a plate or weld cap to the pipe on each side of pipeline and facility left in the ground. This activity will occur both upstream of the station suction valve and downstream of the station discharge valve. It is anticipated that this activity will occur near the fenced boundaries of the stations and terminals to ensure all auxiliary piping is isolated within the pump station or terminal. The precise locations where these activities will occur will be evaluated on a site-specific basis to minimize disruption to any nearby infrastructure due to construction activities. The Superior Terminal will only be isolated on the upstream side of the facility, as it is the terminating facility for the existing Line 3. The pump station and facilities buildings will remain in place and be used for maintenance and storage.

4.2.3.1.2 Mainline Valves (MLVs)

All MLVs will be electrically disconnected as to discontinue operability of the electrical actuators and be closed as a method of segmentation.

4.2.3.1.3 Electrical and Instrumentation

Electrical connections will be de-energized and rendered safe as determined during detailed engineering. Any electrical or instrumentation infrastructure required for the ongoing application of the CP system will be maintained.

4.2.3.1.4 Facilities

The following facilities on the existing Line 3 are locations at which isolation will occur:

- the northern endpoint of the Project located in North Dakota (MLV-789.43-3-B);
- Donaldson Pump Station (MP 814.00);
- Viking Pump Station (MP 847.91);
- Plummer Pump Station (MP 876.97);
- Clearbrook Terminal/Pump Station (MP 909.10);
- Cass Lake Pump Station (MP 952.98);
- Deer River Pump Station (MP 995.83);
- Floodwood Pump Station (MP 1044.33); and
- Superior Terminal (MP 1096.95).

The deactivation process involving the removal of mechanical piping will start with a safety briefing with the staff working on this project to discuss any onsite hazards and mitigation activities. Upon completion, the purging process will begin at each of the stations identified above. All removed piping and equipment will be cleaned and disposed of per applicable regulations. Pipe, piping components, valves, pumps and pipe fittings that are no longer fit for service or reuse within the Enbridge system would be cleaned and disposed of through regional salvage or disposal companies. The removal of the suction and discharge valves and associated piping will isolate the pump stations from the Line 3 mainline, once sealed. Any pipe within each facility that cannot be removed safely will be cleaned and plated so that there is a barrier between the facility and the pipe. The Line 3 pumps will be permanently removed to allow for a safe working area. The sump tank and its associated piping will be cleaned and removed.

The process to disconnect the facilities' electrical systems will start with a safety briefing to discuss any onsite hazards and mitigation measures. A review of the electrical equipment to be disconnected will be performed and equipment identified as non-essential will be removed and salvaged. Items essential for the operations of the adjacent operating lines will be identified and kept in place. A Lock Out/Tag Out tally will be performed on all of the electrical equipment associated with Line 3. If required, a 480 volt pad mounted transformer would be installed to provide power to maintain the yard, building lights and any power needed for CP. All equipment that is no longer fit for service or reuse within the Enbridge system would be cleaned and disposed of through regional salvage or disposal companies in accordance with applicable codes, regulations, and ordinances.

4.2.3.2 Pipeline Segmentation

The Line 3 pipeline will be segmented via the permanent closure of existing mainline valves. In addition, and as required by CFR Part 195, the stations will be isolated from the pipeline and serve as additional segmentation points. When Line 3 was constructed, the valves were strategically placed to prevent volumes of oil from entering sensitive areas in the event of an emergency release during operation and, as such, they will also prevent movement of water within the empty pipe from reaching these same resources.

At locations other than existing MLVs, which will be permanently closed, additional mainline segmentation will be achieved by mechanically cutting the pipeline, removing a short piece of pipe, and welding a plate or weld cap to the pipe on each side of the pipeline left in the ground similar to facility isolation (see Section 4.2.3.1), or by installing a plug of grout. Pipeline segmentation activities will be undertaken in accordance with all applicable federal, state, and local permits.

4.3 MINIMIZING THE RISK OF SUBSIDENCE

The risk of ground subsidence has been identified by CEPA, the Petroleum Technology Alliance of Canada ("PTAC"), and the NEB as a possible concern for permanent deactivation of a pipeline in-place.[1,3,13] The literature recognizes that the long-term degradation of a Permanently Deactivated pipeline may eventually lead to a measureable amount of ground subsidence; however, the extent of that subsidence is not well defined and must be assessed. In order to responsibly deactivate a pipeline, an operator must consider the risks of ground subsidence and develop a plan to address it. The decision to Permanently Deactivate in-place requires that potential ground subsidence levels are within tolerable limits for site-specific land use.[1,3] While guidance for establishing tolerable limits is not presently available in the industry, the information available instead defers to a risk-based decision-making process to support appropriate actions for a specific pipeline.[1]

4.3.1 Structural Integrity and Subsidence Risk Assessments

This section provides details of the assessments of subsidence and structural integrity performed as part of developing the Line 3 Deactivation Plan to predict the short and long-term risks of ground subsidence. It should be noted that subsidence as a general term is used in relation to both natural and artificial hazards, such as growth faults, flood or groundwater withdrawal, and mining operations. However, reference to ground subsidence within this Plan is used solely with respect to possible subsidence concerns related to pipeline deactivation.

Enbridge performed a thorough review of the possible risks associated with ground subsidence with respect to pipeline deactivation, considering industry guidance from the 2007 CEPA Report,[1] the NEB Background and Discussion Papers,[3,5] the PTAC Report,[13] the 2010 DNV GL Report,[6] and additional Enbridge work summarized in this plan. The review identified the following potential consequences related to ground subsidence with respect to pipeline deactivation.

- Public Safety:
  - hazards to agricultural equipment;
  - road subsidence at primary highways;
  - track bed subsidence at railway crossings; and
  - hazards to people, machinery, or livestock.
- Environmental Impact and Land Use:
  - water channeling and subsequent erosion;
  - loss of topsoil; and

    long-term impact on land use.

4.3.1.1 Subsidence Failure Modes

Ground subsidence can occur where a void is created within the ground, generally at the pipe depth, allowing the soil above to collapse into the void, and creating a disturbance at the surface. This may occur due to a combination of corrosion degradation and loss of structural integrity of the pipe wall. Subsidence due to corrosion can be either partial, considering soil infill into large localized perforations in a Permanently Deactivated pipe, or total, considering significant overall general wall loss and total infill of soil.

Structural integrity, in the case of a Permanently Deactivated pipeline, is defined by the ability of the pipeline to resist collapse due to external loading, rather than internal product and pressure containment. DNV GL recognized that an abandoned pipeline sufficiently degraded by corrosion such that structural integrity is compromised could, in theory, collapse due to the weight of the soil and any potential surface loads present.[6,13] The possibility for total subsidence of a large diameter pipeline, (defined by CEPA[1] as having an outer diameter of 24 to 48 inches) is of specific concern for the 34-inch Line 3 because of potential environmental and safety concerns, as mentioned above. While the magnitude of subsidence due to partial infill is generally considered minor,[3] it has nonetheless been assessed in the following sections for comparative purposes.

In 2013, the Petroleum Technology Alliance of Canada (PTAC) commissioned DNV GL to prepare a study entitled “Understanding the Mechanisms of Corrosion and their Effects on Abandoned Pipeline”. The PTAC report presents a conservative methodology proposed by DNV GL for estimating time to loss of structural support for an abandoned pipeline. This assessment considers a worst case condition, assuming no coating (or 100% loss of coating) and no CP applied. However, these assumptions are not applicable to Line 3 since CP will continue to be applied to the pipeline; thus, the corrosion progression is predicted to be localized perforations due to external corrosion and not general wall thinning. Similarly, the conditions for internal corrosion on Line 3 are not consistent with the conditions used in the corrosion aspect of the PTAC model.

4.3.1.2 Corrosion Degradation

The structural integrity of a pipeline in a load bearing capacity is subject to decrease with corrosion degradation. The specific rate of corrosion due to exposure to the environment depends on a number of factors, including the condition of the pipeline coating, soil aeration, types and homogeneity of soils, soil moisture, internal atmosphere, and electrical factors which create the potential differences for a corrosion cell to be established.

Line 3 has been in service since 1968. The types of environmental degradation normally affecting onshore pipelines of similar vintage are:

- localized corrosion;
- uniform corrosion;
- stress corrosion cracking (SCC);
- corrosion fatigue; and
- selective seam weld corrosion.

Localized pitting and uniform corrosion, both external and internal, are the only two forms of corrosion that are relevant with respect to pipeline deactivation and contribution to subsidence. SCC, corrosion fatigue, and selective seam weld corrosion are unlikely to affect the structural integrity of the pipeline because they have a crack-like morphology that can grow to failure under an applied high hoop stress from internal pressure. The Permanently Deactivated Line 3 will not be under hoop stress due to internal pressure. In the absence of internal pressure, the primary stresses in the circumferential (hoop) direction will be minimized. As such, the driving stresses for continued SCC or corrosion fatigue crack growth are expected to be negligible. Therefore, SCC, corrosion fatigue, and selective seam weld corrosion are not considered as contributing factors to the risk of pipe collapse and subsidence caused by Line 3.

4.3.1.3 Effects of Coating and Cathodic Protection on Corrosion

External corrosion control is generally achieved on underground pipelines by a combination of corrosion resistant coatings and CP systems. Corrosion resistant coatings are designed to provide high dielectric strength, and low moisture permeability. The coating, where intact, provides a barrier to moisture, which is necessary to support the corrosion reactions. However, coatings contain defects, or ‘holidays’ where corrosion can occur. Furthermore, coatings can degrade with time which increases the extent of bare pipe surface susceptible to corrosion.

Generally, pipeline corrosion on an externally coated pipeline will primarily progress as localized pitting with general corrosion occurring at coating holidays, or where coating is disbonded.[13, 37] Per historical industry experience and guidance from CEPA and the NEB, it is considered highly unlikely for corrosion to cover the entire circumference of a pipeline over a significant length.[1,3] Thus, it is correspondingly unlikely that a long segment of the pipeline will be potentially susceptible to sudden collapse and subsidence. It should be noted that the 2011GE UltraScan®

WM in-line inspection data collected on the most severely corroded section of Line 3 revealed that approximately 99% of the inspected pipe joints contained corrosion that was <10% of the pipe's total surface area. This data substantiates the guidance provided by CEPA and the NEB that it is considered highly unlikely for corrosion to cover the entire circumference of a pipeline over a significant length.[1,3]

Line 3 is externally coated with polyethylene tape. A Gas Research Institute (GRI) report published in 1992 provides information that the most common problems reported by pipeline operators who had used tape coating on their pipeline systems were: poor field application, failure of adhesive, poor resistance to soil stress, and high susceptibility to shielding the current of the CP system.

Data collected from the 1996 direct examinations conducted on Line 3 was reviewed to provide a baseline for historical metal loss on this line. There were 49 locations excavated between 1978 and 1982 based on the findings of the in-line inspection (ILI) tool. External metal loss was found at 15 of these locations, all under wrinkled and disbonded tape. Excavations conducted on Line 3 have provided confirmation that the polyethylene tape is experiencing disbonding due to soil stress promoting the formation of wrinkles (on the coating) at the point of maximum stress, typically at the 3 o'clock and 9 o'clock circumferential positions of the pipe. (For reference, circumferential positions are indicated in terms of clock divisions looking downstream, with 12 o'clock representing the top centerline of the pipe.) Once the wrinkles form, water is able to seep under the disbonded coating and is carried along the pipeline's steel surface by capillary action. Permeation of the CP current is limited due to high dielectric strength of the polyethylene tape shielding the current.

4.3.1.4 Estimate of Corrosion Rates

A review of historical and conservative theoretical external and internal corrosion rates was undertaken to help establish a predicted time to failure for possible pipeline collapse, and related ground subsidence.

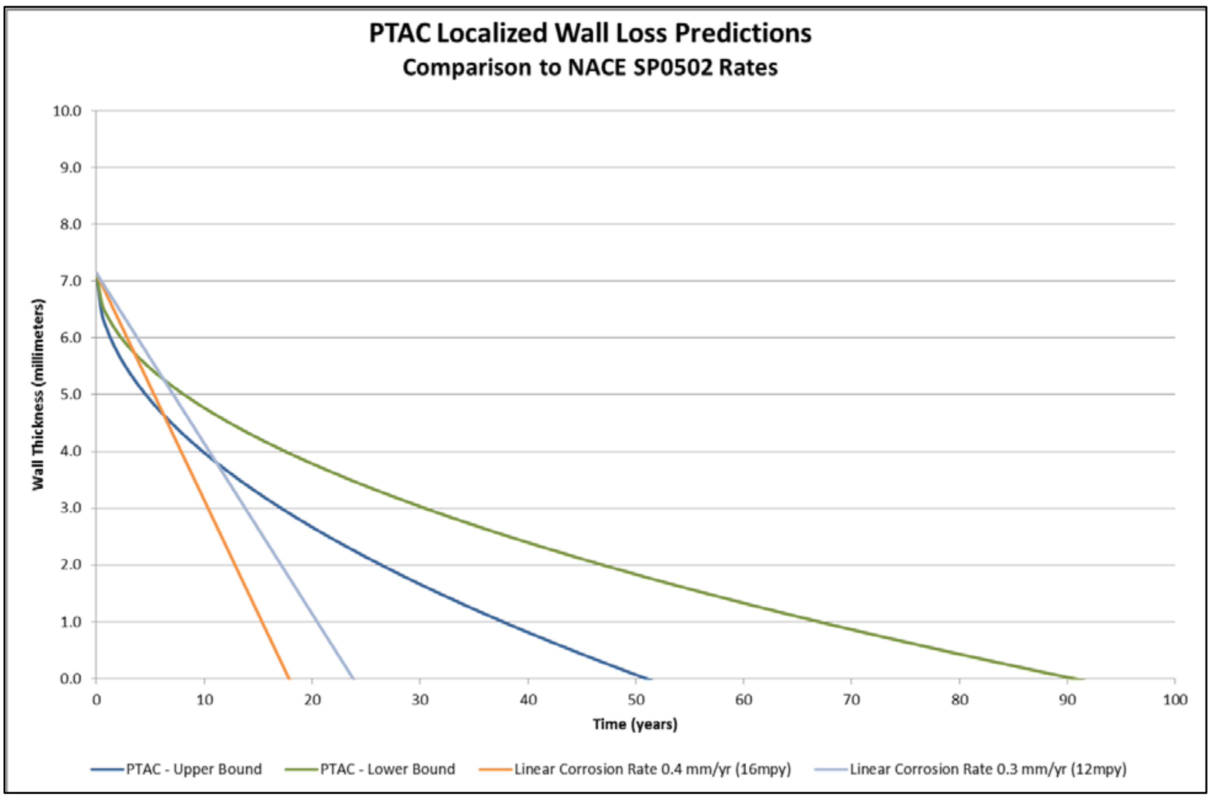
4.3.1.5 External Corrosion Rates

The U.S. National Bureau of Standards (NBS) initiated an extensive series of tests in 1922 to measure corrosion rates of various metals and alloys in a number of soil environments.[14] The soils studied were the native soils in over 150 test sites from around the United States. The soils were analyzed for pH, total acidity and the concentrations of sodium, potassium, calcium, magnesium, carbonate, bicarbonate, chloride and sulfate ions. The soil resistivity values were measured and the local climatic conditions were recorded.[14]

The numerical analysis provided in the PTAC report was used to calculate the localized corrosion rate and the uniform corrosion rate, as a function of soil drainage, assuming it was limited by ionic diffusion of oxygen through a surface oxide. The soil drainage was the only parameter that showed a weak but usable correlation between the mass loss (uniform corrosion) and the localized corrosion, with soils drainage. The wall thickness of the pipe was calculated with respect to time for the two extreme soil drainage conditions: very poor and good. The results are presented in Figure 4-6.

A 0.4 mm/year (16 mils/year [mpy]) default corrosion rate for pipelines when other data are not available, is presented by ANSI/NACE SP0502-2010, "Pipeline External Corrosion Direct Assessment Methodology" (SP0502).[15] This corrosion growth rate was developed using an 80% probability bound (X80) value, established by the NBS study discussed above. SP0502 also provides a default pitting rate of 0.3 mm/year (12 mpy) for pipelines when other data was not available, provided that the piping has had at least 40 millivolts (mV) of polarization for a significant period of time since installation. This 0.4 mm/year growth rate was calculated from long-term underground corrosion tests of bare steel pipe coupons in a variety of soils, including native and non-native backfill, and is considered conservative for most transmission pipelines.[15] NACE guidance allows for a 24% reduction of this default rate, yielding the 0.3mm/year rate cited.[15]

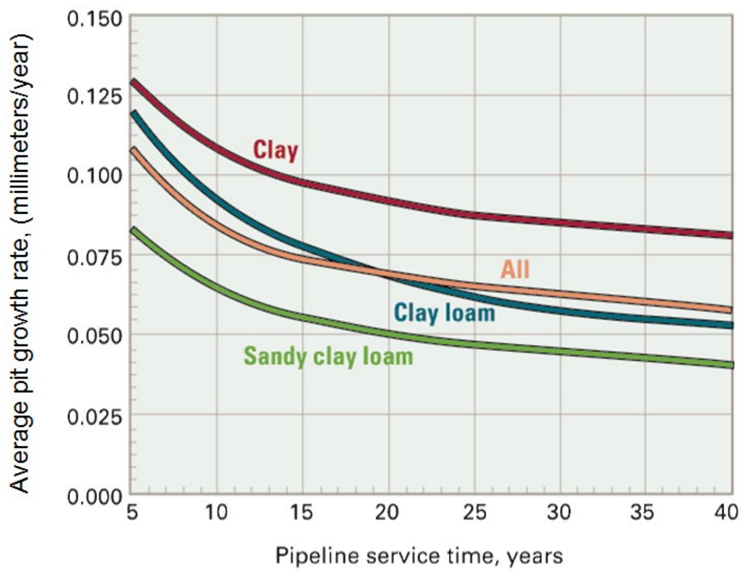
Figure 4-6: Upper and Lower Bound Wall loss progression due to corrosion as a function of soil drainage (PTAC). Applicable NACE SP0502 corrosion rates have been included for comparison.



These corrosion rates are generally considered conservative as presented below in Section 4.3.6, but are presented for comparison.

Both general and pitting corrosion rates have been shown to decline with age, as shown in Figure 4-7.[17] Velazquez presented a statistical analysis of over 250 excavations to predict the long term rates of pitting corrosion over a 40 year period.[17] For comparison, the worst case pitting growth rate (based on the X80 value) for the various soil types considered in this study was presented as 0.119 mm/year (4.7 mpy), or roughly a third of the 0.4 mm/year growth rate proposed by NACE.[15]

Figure 4-7: Average Corrosion Pitting Growth Rates as a Function of Time and Soil Classifications **(Reproduced from Oil and Gas Journal – Corrosion)**[17]



4.3.1.6 Historical Corrosion – Leaks and Ruptures

In an effort to better understand historical external corrosion performance for Line 3, the historical incidents along the entire length of Line 3 and the most recent integrity data for a representative section was reviewed. There have been five in-service incidents, the last of which was in 1997, in which external corrosion was either the cause or played a significant role in the cause of the incident; one was due to extensive general and pitting corrosion, three were due to cracks at the bottom of a deep pit, and the other was classified as narrow axial external corrosion. These incidents were caused by localized defects in the pipe wall and not general wall loss. From examination of the integrity data, there is no indication of significant areas of general wall loss and therefore the structural integrity of the pipe as a load bearing structure will not be significantly affected.

Data from the 2011 GE UltraScan® WM in-line inspection conducted on the most severely corroded section of Line 3 was reviewed to provide an assessment on the prevalence and severity of the metal loss on line. Table 4-2 summarizes the percentage of anomalies identified during inspection along this 255 km long section of Line 3. After approximately 60 years in service, over 50% of the anomalies identified were reported with an external metal loss less than 20% of the nominal wall thickness. Based on this 2011 data, less than 0.5% of the anomalies were reported with an external metal loss greater than 50% of the nominal wall thickness.

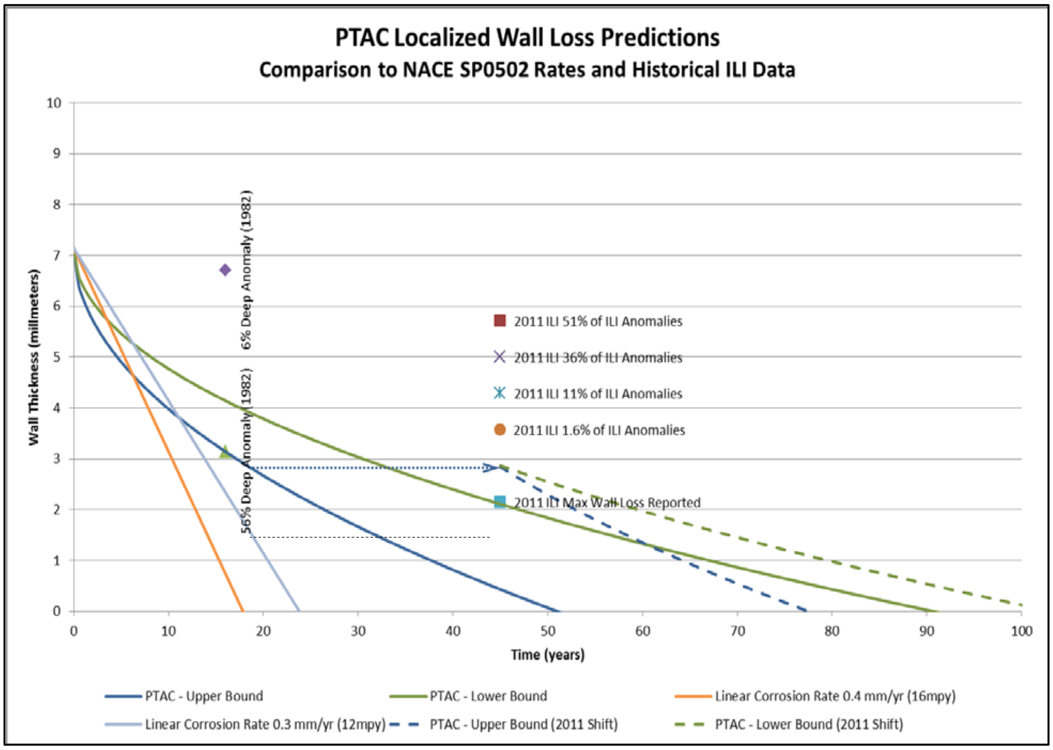
Table 4-2: Depth Distribution of External Metal Loss Anomalies Reported by 2011 WM Inspection for Line 3

Wall Loss as Percentage of Nominal Wall Thickness	Percentage of Total Anomalies (%)
≤ 20%	51.2
20 - 30%	36.4
30 - 40%	10.4
40 - 50%	1.6
≥ 50%	0.45

When comparing the 2011 ILI results to the localized corrosion data presented in the PTAC Report, a time to perforate the Permanently Deactivated Line 3 due to external corrosion may be estimated.[13] Figure 4-8 shows the wall thickness reduction with time due to localized external corrosion under two types of soils, one considering good drainage resulting in a lower bound corrosion rate (PTAC Lower Bound), and one with very poor drainage resulting in an upper bound corrosion rate (PTAC Upper Bound). The 1982 ILI data is also included in the plot for comparison. Reviewing the depth and time related to the worst case 56% deep through wall anomaly, identified in 1982, shows good comparison with the predicted curve for the worst case soil conditions. Based on the information presented in Figure 4-8, the worst case time to failure, from the original installation is estimated at 51 years. Based on this, it would be assumed that the pipeline is already penetrated or is likely to be within the next five years considering an in-service date of 1968. This demonstrates the over-conservative nature of the corrosion rates presented in the PTAC Model when compared to the corrosion rates experienced on Line 3. The time to penetration is linked to the time when internal metal loss due to corrosion could begin as a result of the ingress of ground water and soil to the internal surface of the pipe.

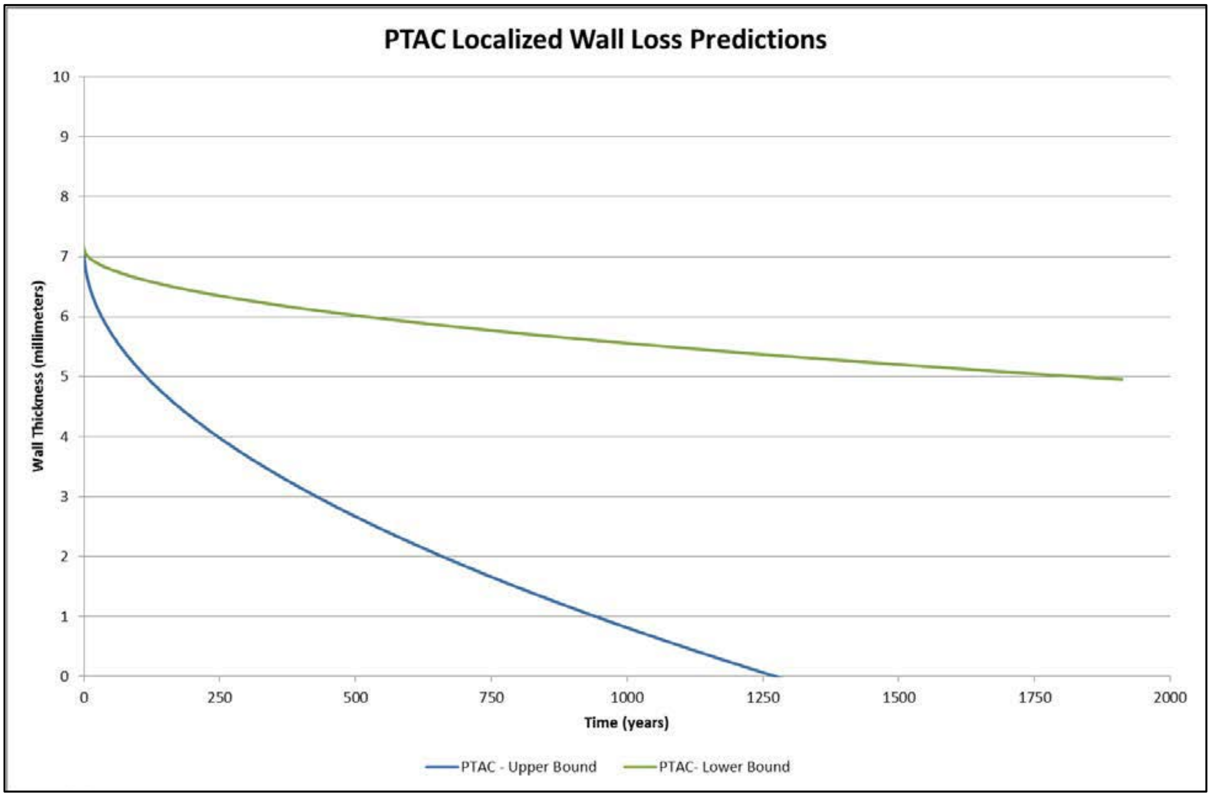
Reviewing the data from the 2011 ILI run, however, and assuming that the largest anomalies with external metal loss greater than 66% of the nominal wall thickness were repaired, it can be shown that the worst case anomaly is approximately 60% through wall as of 2011. Taking the degradation curve based on the PTAC Upper and Lower Bound corrosion rates and shifting those curves accordingly to represent a 60% through wall pit at 2011, as shown with the dashed curves in Figure 4-8, yields estimates of time to through wall penetration based on the PTAC model between 25 to 50 years from 2011. This only represents through-wall corrosion and not failure or collapse.

Figure 4-8: Upper and Lower Bound Wall loss progression due to corrosion as a function of soil drainage (PTAC). Historical metal loss inspection data collected on Line 3 has been included for comparative purposes.



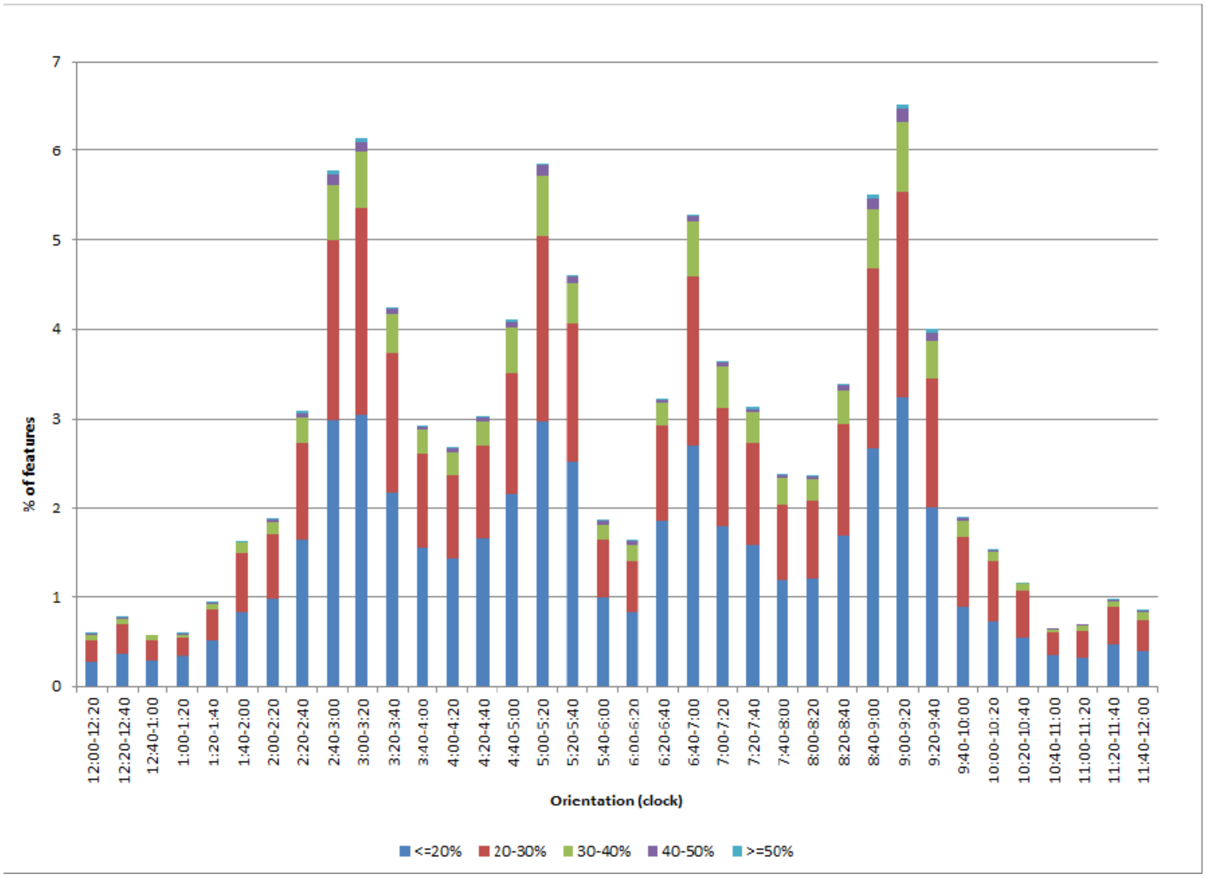
An analysis was conducted to evaluate the time it would take for the entire pipe wall thickness to corrode to zero due to uniform corrosion. Figure 4-9 shows the wall thickness reduction with time due to uniform external corrosion under types of soils, one considering good drainage resulting in a generally moderate corrosion rate (green curve), and one with very poor drainage resulting in a more aggressive corrosion rate (blue curve). The worst case estimates for time to total pipe degradation due to generalized corrosion, based on the PTAC model are greater than 1,250 years.

Figure 4-9: Pipe Wall Thickness Affected by Uniform Corrosion as a Function of Time and Drainage of the Soil (PTAC). Comparison to 2011 ILI Results.



The distribution of the external metal loss around the circumference of the pipe reported by the 2011 ILI run is presented in Figure 4-10. The sides of the pipe (2:40 to 3:40 o'clock and 8:40 to 9:40 o'clock) generally contained the highest percentage of external metal loss. This finding is most likely attributable to the fact that polyethylene tape coatings, such as that used on Line 3, are susceptible to soil stresses that result in wrinkling and disbondment along the sides of the pipe.[39] Due to the shielding characteristics of the coating, the CP system would not be able to adequately protect the pipe surface under the areas of disbondment.[18] The data presented in this figure does not suggest that the entire circumference of Line 3 is being corroded at a uniform rate and thus, there is no evidence to currently suggest that there are segments of Line 3 potentially susceptible to sudden collapse and abrupt subsidence.

Figure 4-10: Orientation of Metal Loss Features Reported by the 2011 GE UltraScan® WM In-Line Inspection of a Representative Section of Line 3



4.3.1.7 Predicted External Corrosion Progression

In its 1996 Report, the NEB presents a mechanism of corrosion leading to ultimate structural failure of a pipeline. Based on a review of the literature presented, industry guidance, and historical industry experience, a predicted external corrosion progression is proposed below to establish a relative understanding of the long term corrosion mechanisms.[1,3,6,13,14,17,19] The predicted external corrosion progression assumes Enbridge will continue the application of CP as part of its ongoing Operations and Maintenance programs as described in Section 4.3.2.1.

- After Permanently Deactivating Line 3, external corrosion is expected to progress in a similar manner with what has been historically observed.[1,3,6,13 12]
    - External corrosion is expected to grow at the locations of coating holidays, or disbonded coating, similar to the locations presented in Section 4.3.1.6.[3,13 14]
    - Pitting corrosion is expected to be the primary form of corrosion on Line 3 as opposed to large scale general corrosion; this assumption is consistent with the findings from the 2011 GE UltraScan® WM in-line inspection conducted in the most severely corroded section of Line 3 in which approximately 99% of the pipe

joints inspected contained corrosion that was <10% of the pipe's total surface area.

- The external corrosion is expected to continue being localized on the sides of the pipe, where the highest percentage of external metal loss has been measured, as discussed in Section 4.3.1.6.
- External corrosion is expected to be the dominate degradation rate until pits penetrate through wall, allowing moisture ingress into the pipeline.[3,13]

- Once external perforations have developed, water or soil may accumulate within the pipeline, and internal corrosion may progress as presented in Section 4.3.1.8.[13] This accumulation is expected to occur over hundreds of years.

- As the coating degrades and disbonds, more of the pipeline surface will be exposed. Areas where coating fails completely (i.e. exposing the external surface of the pipe to the surrounding soil), will be accessible to the CP system and thus, subsequent corrosion growth would be minimized. By contrast, locations where the coating is disbonded but remains intact will be shielded from the CP system and subject to continued corrosion as discussed in Section 4.3.1.3.[3,13]

The corrosion analyses presented in the NEB study indicated that due to the slow rates of pitting corrosion, and their localized nature, complete structural failure is not expected to occur for decades, or even centuries.[3] The findings from the NEB study are consistent with the type of corrosion present on Line 3 and the time estimates presented in Section 4.3.1.6, based on the PTAC Model. Furthermore, based on the random nature of pitting corrosion, it is considered unlikely that localized pits would coalesce to the point of significant pipe collapse.[3,13]

4.3.1.8 Predicted Internal Corrosion Progression

The predicted internal corrosion progression assumes the pipe has been cleaned, and residual moisture levels are as proposed in the cleaning program (Appendix 7.1). It is also assumed that corrosion due to microbially induced corrosion ("MIC") is negligible. Based on minimal amount of water, MIC results in insignificant degree of corrosion.

1. Internal corrosion is expected to be minimal until large enough external perforations occur to allow moisture or soil to enter.

   The findings from the 2011 GE UltraScan® WM in-line inspection conducted in the most severely corroded section of Line 3 revealed that only 0.4% of the pipe joints within the inspected section of line contained internal metal loss features. In total, only 122 internal metal loss features were detected in this section, and half of those had a reported length of ≤50 mm which would typically be indicative of pitting corrosion. With no product in the line and assuming the line is sufficiently cleaned and dried, the research performed by DNV GL and NGA/NYSEARCH related to casing corrosion is applicable for reference. In this study, 39 bench, small-scale, and field tests were performed for a variety of casing environments. Field testing of a bare, cathodically-protected carrier pipe with a dry, vented environment showed no pitting on corrosion coupons and very low corrosion rates with a maximum of 0.002 mm/year (0.08 mpy) at all pipe positions except for the bottom of the line (6 o'clock). At the 6 o'clock position, an average corrosion rate of 0.05 mm/year (2.01 mpy) was observed. Although the annular environment was reportedly dry, the vent may have allowed for ingress of moisture and oxygen. Similarly, it is expected based on the cleaning program that any residual moisture will not have sufficient volume to pool, and the pipeline will have low oxygen content as nitrogen will be used to drive the cleaning pigs. However, it is considered that there may be a possibility of residual moisture in areas of existing internal pits, undercuts, or other defects that are not sufficiently dried during cleaning. Therefore, given lack of other specific data, it may be considered that an internal corrosion rate of 0.05 mm/year be used to provide a conservative estimate of the internal corrosion rates prior to perforation of the pipe wall.

Based on estimates above in Section 4.3.1.6, time to through-wall penetration is estimated to be between 25 to 50 years from 2011.

2. After the first perforations form, the rate of internal corrosion is expected to accelerate.

Two scenarios were addressed, comparable to the scenarios presented in the DNV GL Scoping Study;[6] namely, considering complete fill of the pipeline where the water table is above the pipeline, and partial filling of the pipe due to moisture ingress where the water table is below.

For the first case, a proposed progression is presented in the DNV GL Scoping Study, as follows.

For Case 1, it was assumed that the pipe fills with aerated groundwater. Since the solubility of oxygen in water is low (< 8 ppm), the oxygen in a pipeline will be consumed rapidly for typical corrosion rates. For example, the oxygen in a 24-inch diameter pipeline will be consumed in around one week at a corrosion rate of about 0.1 mm/yr. After the oxygen is consumed, the corrosion rate will drop to negligibly low values. Anaerobic bacteria may accelerate the corrosion rate somewhat, but significant damage would not be expected based on measured corrosion rates for deep steel pilings (Beavers 1998), or buried subsea artifacts (J. A. Beavers, G. H. Koch, and W. E. Berry, "Corrosion of Metals in Marine Environments," Metals and Ceramics Information Center, MCIC Report 86-50, 1986). Furthermore, resupply of oxygen in the pipeline would be very limited unless there were a large number of large holes present in the pipeline.[6]

For Case 2, considering a partial fill scenario, when the pipe has perforated, the internal surface will be exposed to moisture and possibly soil. In the DNV GL and NGA/NYSEARCH study, small-scale testing of bare carrier pipe exposed to air and a static level of brackish water (1/2-filled annular space) showed an average corrosion rate of 0.22 mm/year (8.61 39 mpy) and an average pitting rate of 0.45 mm/year (18.1 mpy).[19] It should be noted that these rates were observed primarily at the water/air interface, which was located at the 3 o'clock and 9 o'clock positions in this experiment. Other locations around the pipe showed relatively low corrosion rates, with a maximum rate of 0.06 mm/year (2.20 mpy) and no appreciable pitting.

If soil enters the Permanently Deactivated pipeline, there is the possibility of these deposits causing localized areas of corrosion, which would be expected to occur along the bottom of the pipe at or near the 6 o'clock position where the soil is likely to settle. For this scenario, the internal surface would essentially act analogous to a bare external surface. ANSI/NACE SP0502-2010 provides a default pitting rate of 0.3 mm/year (12 mpy) for pipelines when other data are not available, provided CP level of the piping has had at least 40 mV of polarization for a significant fraction of time since installation.[16] This 12 mpy was calculated from long-term underground corrosion tests of bare steel pipe coupons in a variety of soils, including native and non-native backfill, and is considered conservative for most transmission pipelines.[16]

4.3.1.9 Effects of CP

It is expected that given sufficient time, a pipeline that is not maintained, has poor or no coating, and without CP, will eventually collapse due to corrosion. Estimates of this timeframe have been provided in Section 4.3.1.6, as well as from industry references to be decades at the low end, and thousands of years on the high end.[1,3,6,13] The NEB recognizes that maintaining abandoned pipelines while continuing CP cannot completely eliminate the risk of pipeline degradation or collapse. However, it can be expected to significantly slow the corrosion process, and thereby delay any potential subsidence.[5]

It is recognized, however, that polyethylene tape coatings are subject to disbondment, and locations where coating has disbonded will be dielectrically shielded from CP.[39] Enbridge will continue to monitor the Permanently Deactivated pipeline as part of its ongoing Operations and Maintenance programs as described in Section 4.3.2.1 and will continue the application of CP until which time it can be determined that it is ineffective or otherwise detrimental. Continuing the application and monitoring of CP will help to minimize the corrosion at coating holidays. However, corrosion may continue at locations of disbonded coating where water may come in contact with the pipe surface, and the coating dielectrically shields CP.

4.3.1.10 Structural Integrity and Subsidence Estimates

The PTAC model[13] for pipe collapse presents a conservative methodology for estimating time to collapse, defined as time to loss of structural integrity, of an abandoned pipeline. This assessment considers uniform wall loss scenarios, considering no coating (or 100% loss of coating) and no CP.

The primary loads that may contribute to structural collapse are loads imposed by soil cover, and any surface loads transferred to the pipe from forces acting at the ground surface. Surface loads may refer to any loads acting at the ground surface, such as vehicular or equipment loads. The load acting directly at the pipe, or the "effective live load", is generally much less than the loads at the surface, as the loads are dissipated through the soil as they are transferred to the pipe. The degree of this dissipation is dependent on the depth of soil cover. The PTAC report[13] provides calculations methods and summary tables of typical effective live loads for various American Society of Civil Engineers ("ASCE") load and impact factors, which is reproduced in Appendix 7.2 (document titled Appendix 7-9.4 Structural Integrity and Subsidence, Section C-ASCE Loading Conditions). The effects of surface live loads on a Permanently Deactivated pipeline are considered more significant than the loads associated with depth of cover alone.[3,13] If sufficient enough to exceed the structural capacity of a Permanently Deactivated pipeline, the pressures transferred to the pipe will lead to ovalization, as depicted in Figure 4-11. If the loads are sufficient to progress, the pipe may fail through either plastic collapse or elastic buckling, as depicted in Figure 4-12 and as per the PTAC Report[13] and the American Life Alliance Guidelines for the Design of Buried Steel Pipe.[20]

Plastic collapse occurs when bending stress on the pipe walls exceeds the yield strength of the pipe steel. The wall plastically yields, and collapses under the loads on the pipe. Elastic collapse, or buckling, occurs when the elastic energy in the pipe wall exceeds the critical buckling limit. Both failure modes need to be considered in development of collapse assessments.[13] The critical load acting on the pipe to cause this collapse is considered the load bearing capacity of the pipeline.

Figure 4-11: Surface Load and Transmitted Pressured and Corresponding Ovality of Pipe Cross-Section **(Reproduced from American Lifelines Alliance)[20]**

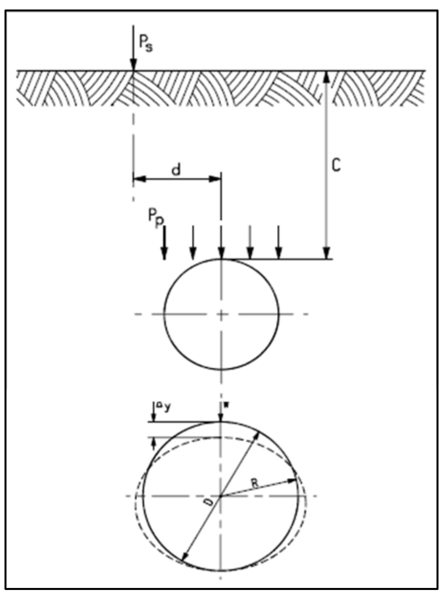
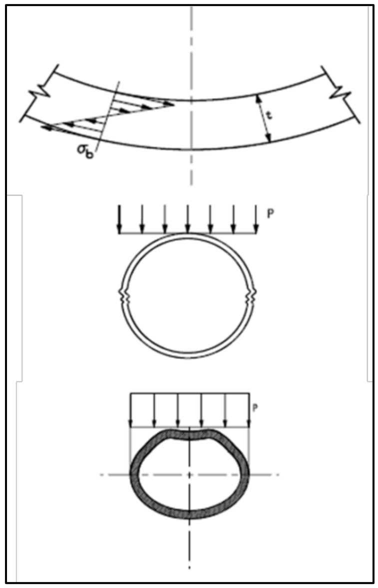


Figure 4-12: Through-Wall Bending Stress, Crushing of the Side-Wall, Elastic Buckling of Pipe Cross-Section **(Reproduced from American Lifelines Alliance)**[20]

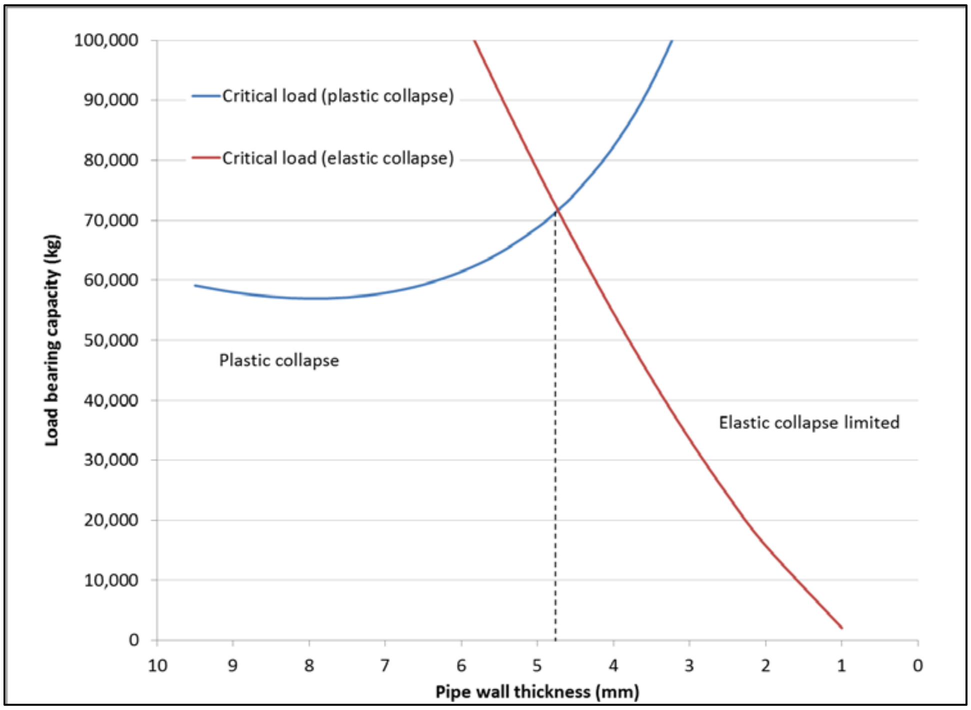


The PTAC model presents a methodology to assess the load bearing capacity of a pipeline as a function of wall thickness, considering both plastic and elastic collapse. An example plot is presented in Figure 4-13, where the blue curve represents the load bearing capacity as limited by plastic collapse, and the red curve represents the load bearing capacity as limited by elastic collapse. It should be noted that the load bearing capacity is not directly decreasing with the decrease in wall thickness. As the pipe wall becomes thinner, the stiffness of the pipe wall decreases. The decreased stiffness increases resistance to plastic collapse, until the point where elastic buckling is the controlling failure mode as described within the PTAC report.

As represented in Figure 4-13, the pipe can fail in two ways (elastic and plastic). As the pipe wall thins, the wall becomes more flexible being able to support greater loads following the blue curve. At the intersection of the curves, the pipe becomes weaker; following the red curve as the wall thickness decreases until failure results from a given load.

Figure 4-13: Example Plot of Load Bearing Capacity as a Function of Pipe Wall Thickness 2

(Reproduced from PTAC)[13]



4.3.1.11 Lapse Due to Generalized Corrosion

Structural integrity models presented by PTAC ("PTAC Model") were analyzed to assess the load bearing capacity of the Permanently Deactivated Line 3 as a function of corrosion damage. As the Permanently Deactivated pipeline corrodes, the load bearing capacity will be reduced. Analyses were performed to estimate the critical surface load necessary to cause pipe collapse, the corresponding soil subsidence geometry, and the pipe stresses associated with various surface loading scenarios.

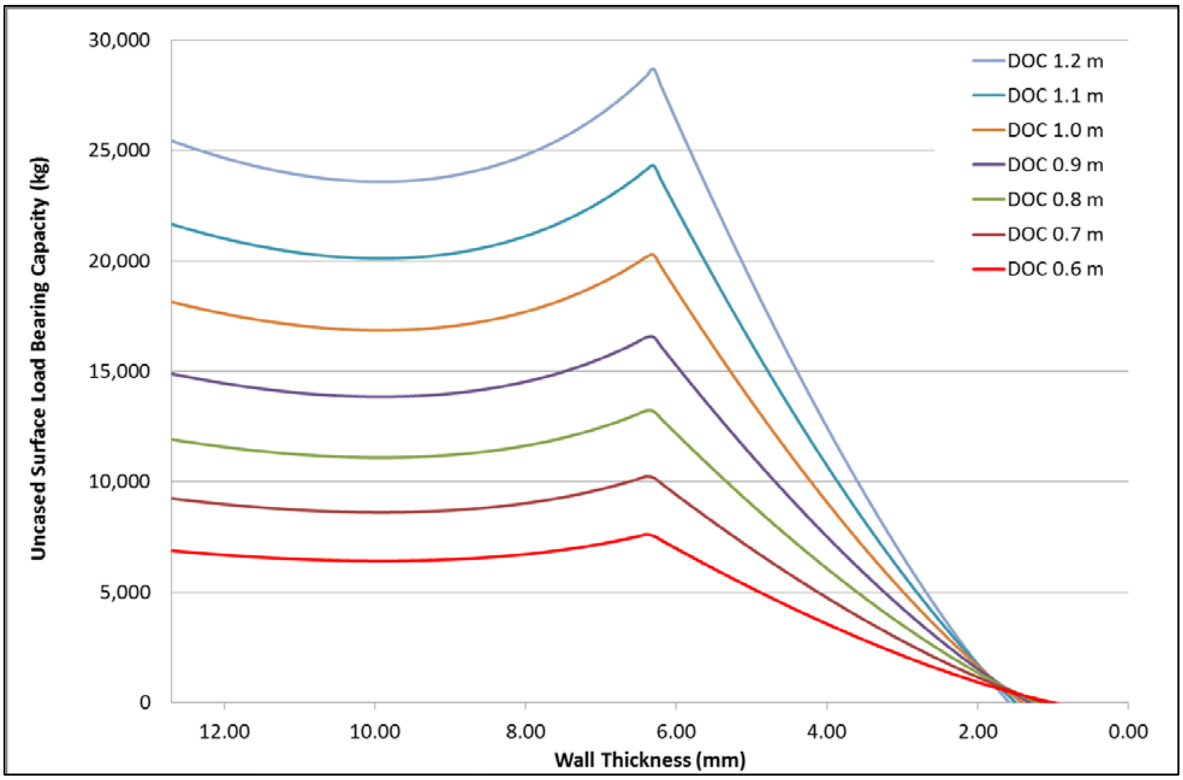
The load bearing capacity of a 34-inch pipeline comparable to the Permanently Deactivated Line 3 was analyzed using the combined PTAC model for plastic and elastic collapse. It should be noted that the PTAC model is considered a conservative estimate, as it assume generalized corrosion, no coating, and no CP, which are not representative of conditions on the Permanently Deactivated Line 3. However, it may be used to establish a conservative lower bound estimate. Input assumptions were used, as required, based on known or approximated conditions along Line 3. They are summarized below, and detailed in Appendix 7.2, Section B – PTAC Model Setup:

- Max Soil Density = 2000 kg/m3
- X52 Pipe (52,000 psi = 359 MPa)
- 34" Diameter (863.6mm)

- Young's Modulus (E = 205 GPa)
- Soil Modulus (E') = 6.9 MPa
- Bedding factor = 0.1
- Lag factor = 1.5
- Stress Intensity Factor = 3
- Impact factor = 1.75

Figure 4-14 presents the estimated surface load bearing capacity as calculated by the PTAC model for a 34-inch pipeline as a function of remaining or effective wall thickness. The surface load bearing capacity curve considers both plastic collapse and elastic buckling, as indicated on Figure 4-14. The surface loads represented in Figure 4-14 consider a point load acting at the ground surface in kilograms, and is generally conservative as surface loading will be distributed over a given area. The data is presented, however, to demonstrate the effect of depth of cover with respect to the surface load bearing capacity of a Permanently Deactivated pipeline.

Figure 4-14: Uncased Load Bearing Capacity Versus Wall Thickness as a Function of Depth of Cover



In order to allow for direct comparison with typical loading scenarios ASCE loads for known conditions, Enbridge considered the effective live load bearing capacity, or the load acting at the pipe as described in Section 4.3.1.10.

Figure 4-15 presents the effective live load capacity, for an uncased pipe, calculated as above. The effective live loads due to various surface load conditions are presented for comparison. An E80 load simulates an 80,000 lbs/ft. railway load, with impact loading considerations as defined by ASCE. An HS20 load simulates a 20-ton truck traffic load as defined by ASCE.[20] The personal truck load simulates a 5-ton vehicle traffic load. The minimum wall thickness necessary to resist collapse for a given load is found where the horizontal load lines intersect the corresponding DOC curve, as represented by the vertical dashed lines. For example, considering an HS20 load scenario at 0.6 m (2 ft.) DOC, the minimal wall thickness to resist collapse is found where the red curve representing the 0.6 m (2 ft.) DOC intersects the horizontal live load line for an HS20 load 0.6 m (2 ft.), at 2.6 mm for this example.

It should be noted that the effective live loads presented in Figure 4-15 represent the live load acting directly at the pipe, considering allowable contribution from surface loading. The live load capacity decreases slightly with depth of cover, as the contribution from soil loads will be greater at depth. The data presented in Figure 4-15 indicates that the added load from soil is minor in comparison to the benefits of depth of cover, however. For comparison, considering an HS20 load at the ground surface, the effective live load at the pipe for a relatively shallow depth of cover of 0.6 m (2 ft.) is two times greater than the effective live load considering a 1.2 m (3.9 ft) depth of cover, while the load capacity is only reduced approximately 6% due to soil loading.

Figure 4-15: Uncased Effective Load Bearing Capacity Versus Wall Thickness

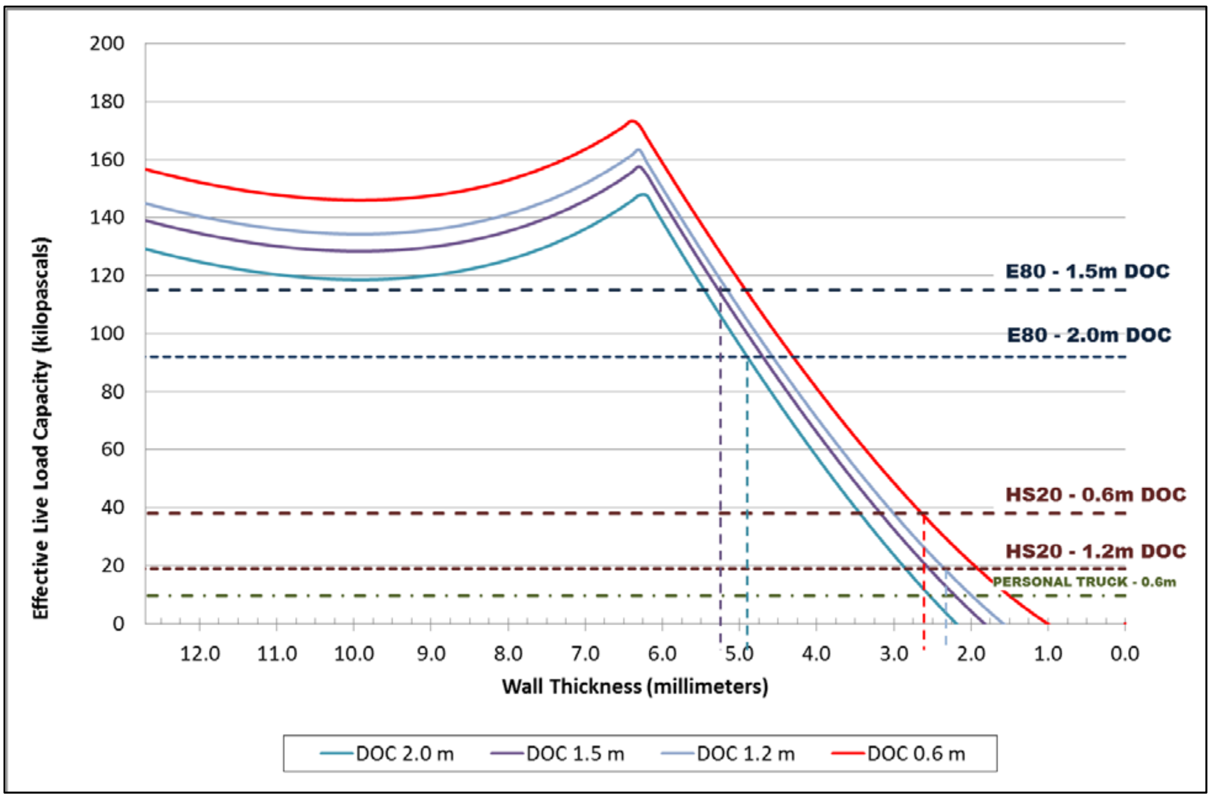


Table 4-3 summarizes the minimum effective wall thickness necessary for the Permanently Deactivated Line 3 to resist collapse considering the three loading scenarios (i.e., personal truck load, 20-ton truck load and 80,000 lbs/ft. railway load). The depths of cover in Table 4-3 are based on the following and are taken from the depth of cover measurements for Line 3 in Canada:

- 0.6 m (2 ft.) is the approximate minimum measured depth of cover in the 2008 depth of cover survey completed on Line 3;
- 1.2 m (3.9 ft.) is the typical depth of cover as measured in the 2008 depth of cover survey completed on Line 3;
- 2.0 m (6.6 ft.) is the minimum expected depth of cover for railway crossings (note: the depth of cover associated with each active railway crossing will be confirmed during detailed engineering); and
- 1.5 m (4.9 ft.) is a conservative estimated depth of cover for railway crossings.

Table 4-3: Minimum Effective Uncased Wall Thickness Capable of Withstanding Highway or Rail Loads

DOC		Minimum Allowable Wall Thickness (mm, in)		
(m)	(ft.)	Personal Truck	HS20	E80
0.6	2.0	1.5, 0.06	2.6. 0.10	N/A
1.2	3.9	1.8, 0.07	2.4, 0.09	N/A
1.5	4.9	1.9, 0.07	2.3, 0.09	5.3, 0.21
2.0	6.6	2.3, 0.09	2.5, 0.10	4.9, 0.19

The key findings from Table 4-3 are summarized below:

- At the minimum measured depth of cover of 0.6 m (2 ft.), the Permanently Deactivated Line 3 is capable of resisting collapse due to equivalent highway loads until sufficient corrosion degradation occurs such that the effective wall thickness is reduced to 1.5 mm, or approximately 78% uniform reduction of the nominal pipe wall thickness for Line 3.
- At a depth of cover of 1.5 m (4.9 ft.),. (expected depth of cover for a railway crossing) the Permanently Deactivated Line 3 is capable of resisting collapse due to equivalent railway loads until sufficient corrosion degradation occurs such that the effective wall thickness is reduced to 0.19 in., or approximately 30% uniform reduction of the nominal pipe wall thickness for Line 3.
- At a depth of cover of 2.0 m (6.6 ft.), (conservative depth of cover for a railway crossing) the Permanently Deactivated Line 3 is capable of resisting collapse due to equivalent railway loads until sufficient corrosion degradation occurs such that the effective wall thickness is reduced to 0.21 in., or approximately 25% uniform reduction of the nominal pipe wall thickness for Line 3.

The 2008 depth of cover survey completed on Line 3 indicates that less than 1% of the line has a depth of cover less than or equal to 0.9 m (3.0 ft,), and over 50% of the line has a depth of cover greater than 1.2 m (3.9 ft.).

It should be noted that these analyses were performed considering only the strength of the carrier pipe. All primary highway and railway crossings are expected to be cased as per original design recommendations. The nominal wall thickness of a casing for a 34-inch carrier varies, but is typically reported to be greater than 12 mm (0.5 in.).[21]

The estimated time required for Line 3 to undergo such environmental degradation that it would collapse was calculated with the assumption that no coating or CP is acting on the line. With active CP and intact coating, the general corrosion rate is expected to decrease, and subsequently the time to failure would be expected to increase.[5] As mentioned above, the nominal wall thickness of a casing for a 34-inch carrier pipe is typically 13-17 mm (0.5-0.7 in.) wall thickness. The 2011 GE MF ILI inspection conducted on Line 3 indicated that all active railway crossings on this line are cased.

Table 4-4 and Table 4-5 illustrate that the predicted time to failure under typical highway loads assuming uniform wall loss (i.e. the pipe wall has thinned to the extent that it can no longer support the live load under a highway or railway) varies from approximately 87 years to over 1000+ years depending upon the assumed wall thickness, soil classification and drainage.

Table 4-4: Time to Failure due to Critical Wall Loss - Highway

Time to Critical Uniform Wall Loss (Highway Load HS20) (years)				
	Soil Internal Drainage and Wall Thickness			
	PTAC Upper Bound Degradation Rates		PTAC Lower Bound Degradation Rates	
Depth of Cover	7.14 mm	12.1 mm	7.14 mm	12.1 mm
0.6 m	506	2237	8100	35797
0.9 m	536	2299	8575	36787
1.2 m	574	2377	9178	38025

Soil Type A: E'= 6.9 MPa, γs= 2000 kg/m3
kml PTAC upper bound degradation rate = 0.2
kml PTAC lower bound degradation rate = 0.05

Table 4-5: Time to Failure due to Critical Wall Loss - Railway

Time to Critical Uniform Wall Loss (Railway Load) (years)				
	Soil Internal Drainage and Wall Thickness			
	PTAC Upper Bound Degradation Rates		PTAC Lower Bound Degradation Rates	
Depth of Cover	7.14mm	12.1 mm	7.14 mm	12.1 mm
1.5 m	87	1166	1399	18660
2.0 m	125	1296	2007	20736

Soil Type A: E'= 6.9 MPa, γs= 2000 kg/m3
kml PTAC upper bound degradation rate = 0.2
kml PTAC lower bound degradation rate = 0.05

4.3.1.12 Pipe Collapse Due to Pitting Corrosion

In addition to the previously discussed model involving a uniform reduction in wall thickness, the PTAC "perforation" model was used to identify the percent of coating disbondment needed to create a pipe collapse scenario due to extensive perforations. The perforation calculations are built upon the plastic collapse model and the assumption that as the corrosion progresses, randomized pitting will be the predominant mechanism, and that there would still exist some amount of metal between the through-wall perforations.

To calculate the loss in load bearing capacity from a plastic collapse perspective, due to these randomized perforations, the PTAC model assumes that a 1% reduction in the wall thickness corresponds to a 1% loss in load bearing capacity, and a 10% reduction in wall thickness corresponds to a 10% loss in load bearing capacity.

Two perforation scenarios were investigated, one with the depth of cover of 2.0 ft. depth of cover, and another with 3.9 ft. depth of cover (this is the average depth of cover for Line 3 including topsoil cover) as illustrated in Figure 4-16 and Figure 4-17. In each of these scenarios the live loading capacity of pipe with a 7.1 mm and a 12.1 mm wall thickness, based on the range of nominal wall thicknesses for the Permanently Deactivated Line 3, was plotted. Additionally, the live loads transferred to the pipe from both a 5-ton personal truck and a 20-ton truck traffic highway are shown alongside the loading limits of the pipe.

Figure 4-16 and Figure 4-17 show the load bearing capacity of all graphed pipe is higher than the loads imposed by both the 5-ton personal truck and 20-ton truck traffic highway in all valid graphed areas. It is acknowledged within the PTAC report that as the perforation area increases from 20% to 50% or greater, the simple relationship breaks down, and it is not recommended this model be considered. As such, the plots are cutoff at 30% degradation, but demonstrate that the pipe wall will likely maintain a majority of its load bearing capacity until greater than 30% of the pipe's circumference is lost due to coalescing of perforations. The corrosion detected, to date, on Line 3 fits within the applicable portion of these figures based on the 2011 GE UltraScan® WM in-line inspection data, collected on the most severely corroded section of Line

3, that approximately 99% of the inspected pipe joints contained corrosion that was <10% of the pipe's total surface area. A time to collapse analysis could not be completed under this model, as the analysis does not extrapolate accurately past the 30% degradation, and the pipe was not predicted to collapse before that point.

Figure 4-16: Allowable surface loading per Pitting Corrosion Model, at 0.6m (2.0 ft.) DOC

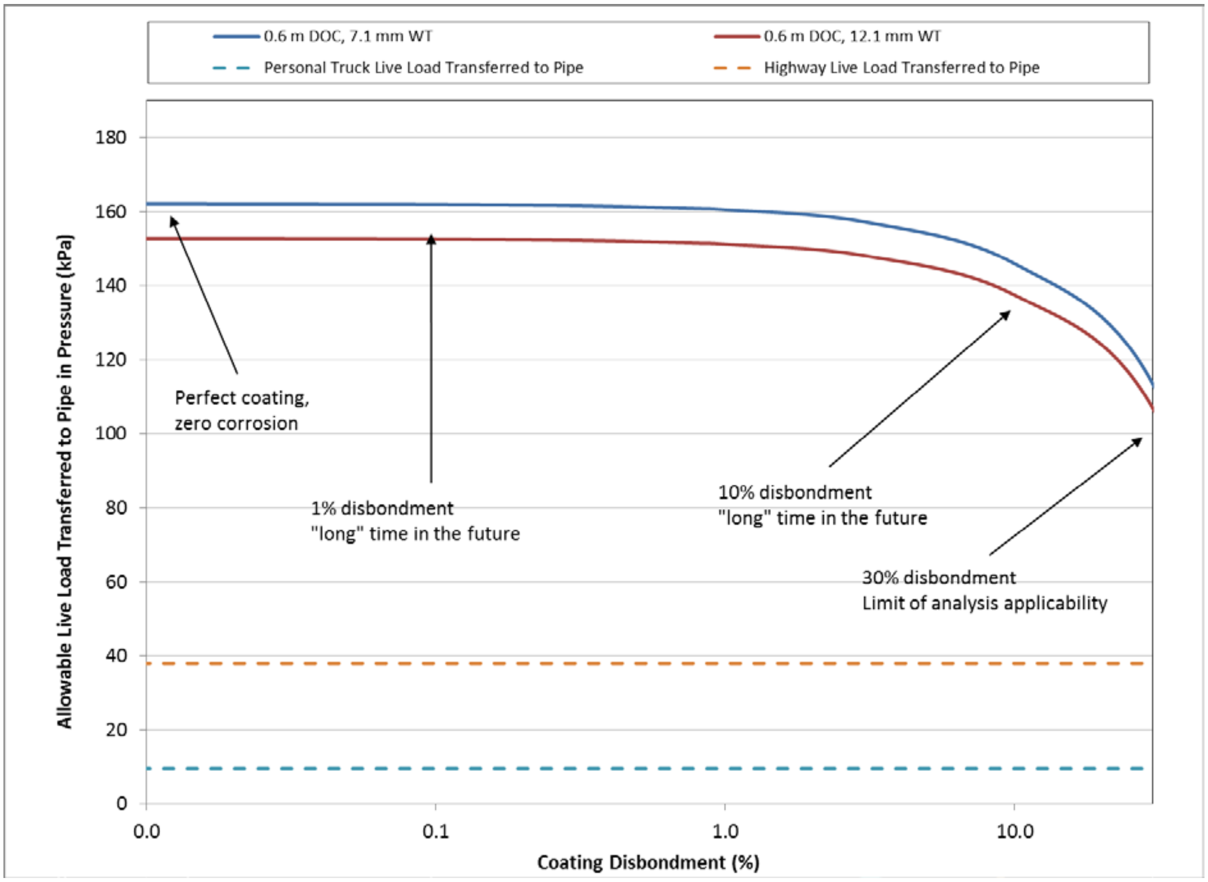
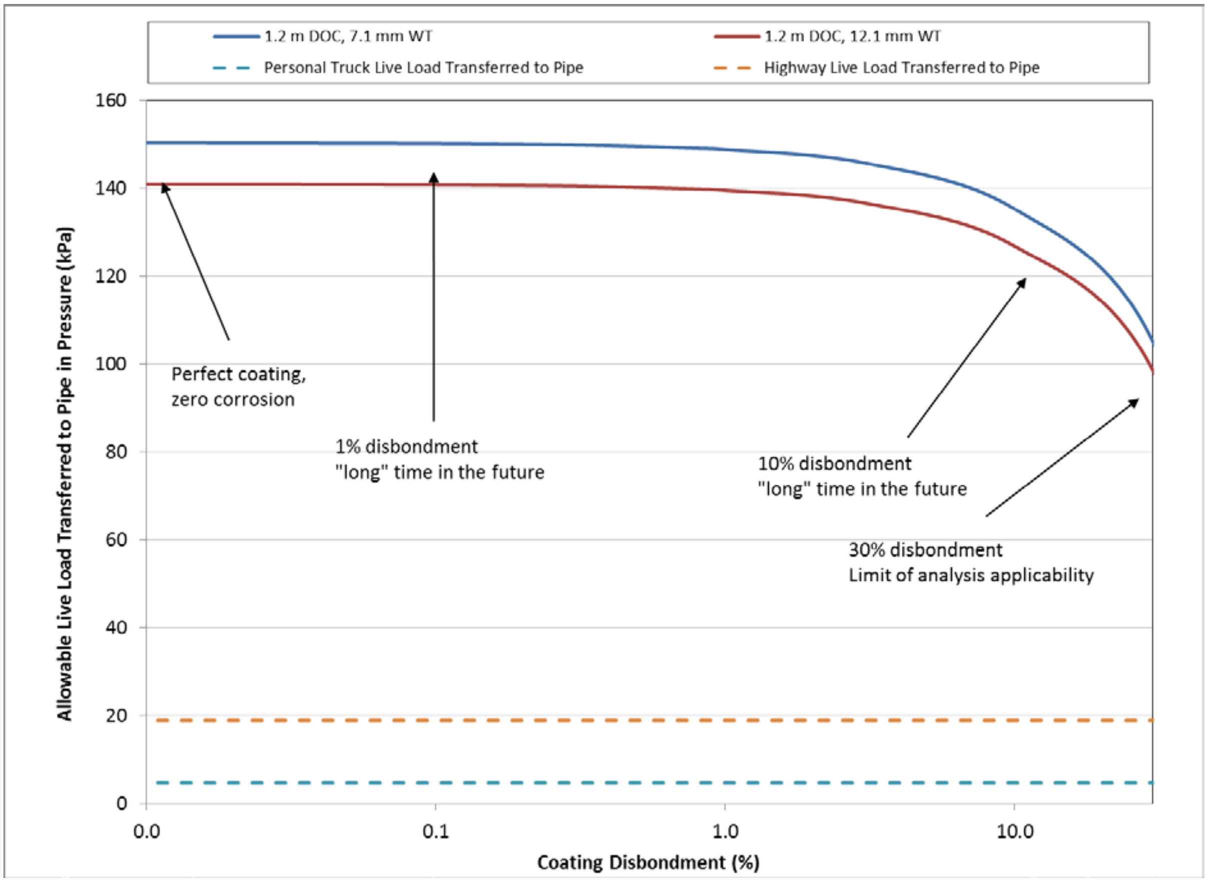


Figure 4-17: Allowable surface loading per Pitting Corrosion Model, at 1.2 m (3.9 ft.) DOC



4.3.1.13 Historical Ground Subsidence

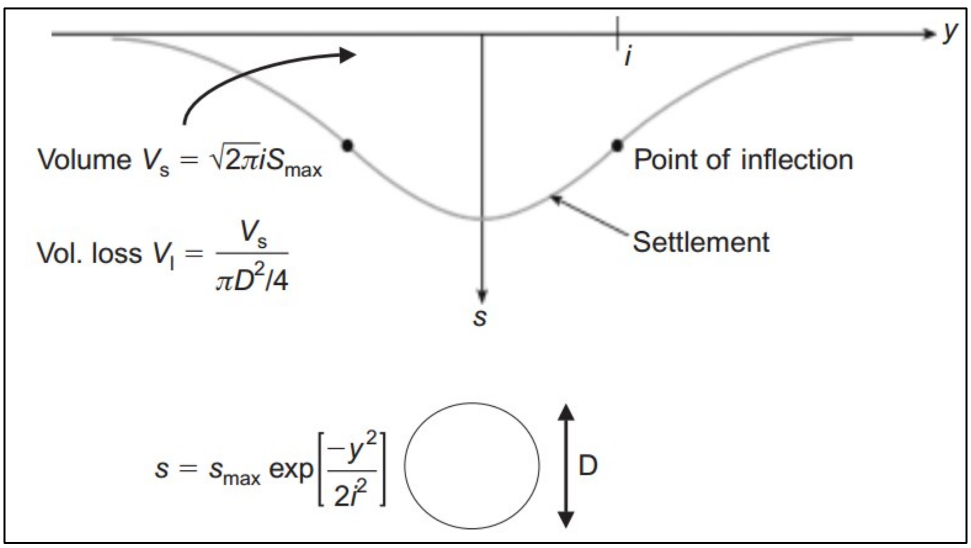
In 1996, the NEB commissioned a study on corrosion and soil mechanics in an attempt to better understand the connection between pipeline corrosion, structural integrity, and the possible ground subsidence that might be observed. The results of this study indicated that there had been no documented incidents of ground subsidence related to pipeline structural failure and this included the approximate 10,500 miles of abandoned or discontinued pipe, as of 1994, in Alberta.[3] The study further stated that ground subsidence associated with the collapse of pipelines is negligible for pipeline diameters up to 12 inches in diameter, at typical depths of cover. Additionally, while there is expected to be some measurable degree of subsidence associated with larger diameter pipelines, it may be small enough to be considered in the tolerable range.[3] The 1996 Discussion Paper concluded after significant study that even under the worst conditions of total structural collapse, ground subsidence would be negligible for pipelines with diameters of 12-inches and smaller. It went on to conclude that for pipelines with greater diameters, the degree of subsidence may be within tolerable ranges.[1] CEPA guidance recommends an assessment to determine the magnitude of subsidence possible for the Permanently Deactivated Line 3, which Enbridge undertook and provided below.

4.3.1.14 Predicted Subsidence Profiles

The rate and magnitude of ground subsidence are generally difficult to predict. Subsidence depends on a complex combination of site-specific parameters, pipe degradation, and soil mechanics properties near the pipeline. In 2014, as part of developing the Engineering Basis for the Line 3 Deactivation Program, Enbridge commissioned DNV GL to provide a geotechnical analysis to determine the possible subsidence levels, and corresponding trough profiles that could occur assuming various levels of pipe infill, up to and including full loss of pipe volume.

Ideally, ground subsidence estimations should consider both total subsidence from pipe collapse at shallow burial depth, and partial subsidence due to excessive ovalization and/or finite soil ingress. Prediction of ground subsidence in the absence of significant external loading can be predicted through analogy with tunneling construction. Extensive field measurements[40,41,42] have shown that the subsidence profile, or settlement trough, during open-face tunneling construction can be well characterized by the Gaussian distribution curve method. Figure 4-18 shows the generic settlement trough, where *i* describes the characteristic half-width of the trough and is a dependent on the depth of cover and soil type. For the scenarios presented for the Permanently Deactivated Line 3, the exact shape of the Gaussian distribution curve can be estimated based on the particular scenario: total pipeline collapse (Vl = 18 1), or partial collapse (i.e., excessive ovalization, or corrosion ingress, 0 < Vl < 1).

Figure 4-18: Generic Ground Settlement Trough Considering Gaussian Distribution Curve Method



A series of assessments were conducted to predict ground subsidence profiles considering 25%, 50% and 100% volume loss at various depths of cover. Note: 100% volume loss represents complete infill of the pipeline (i.e., at the time of collapse, the pipe is completely empty), while the 25% and 50% volume loss estimates represent a partial infill of the pipeline (i.e., at the time of collapse, 75% and 50% of the pipe is filled with soil, respectively), see figure 4-19.

Figure 4-19: Pictorial Representation of Volume Loss for the 100%, 50%, and 25% Scenarios

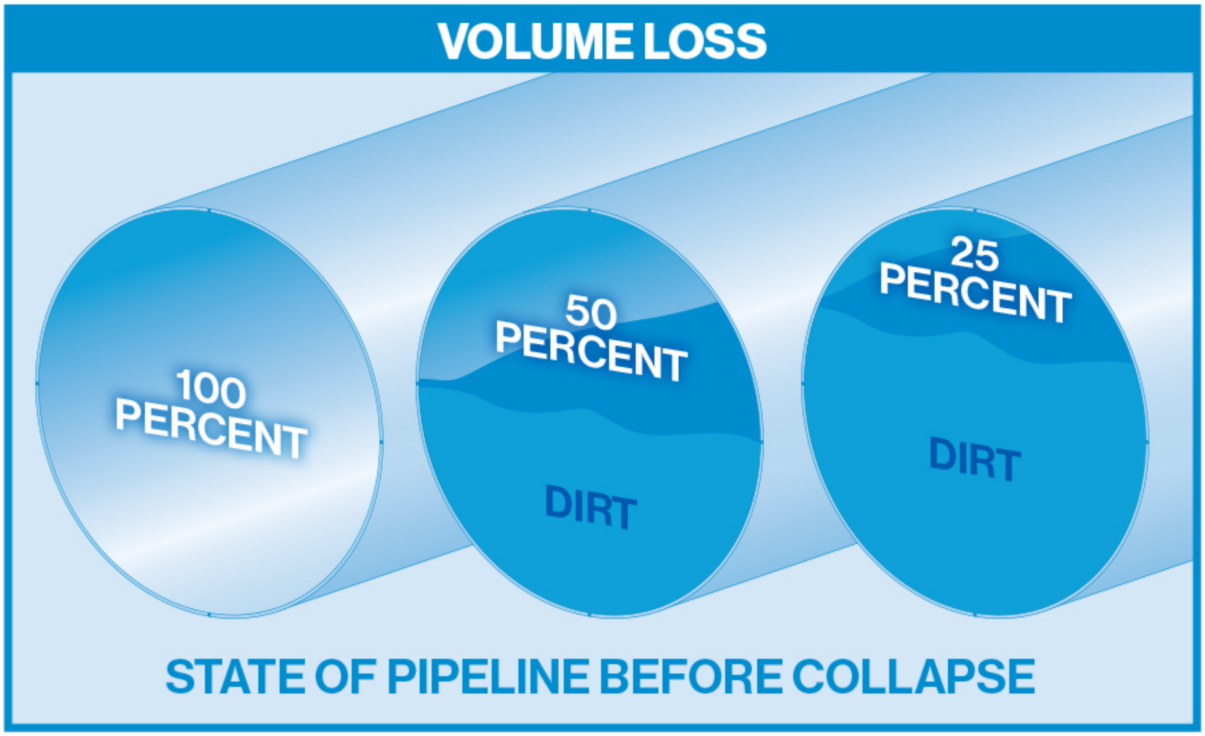


Table 4-6 through Table 4-8 summarize the maximum depth of the ground subsidence expected above the center line of the pipe and the half-width of the settlement trough (*i*) on both side of the pipe's center line at different volume loss values (100%, 50% and 25%) and depths of cover (assumed at 0.6m (2 ft.), 1.2m (3.9 ft.), 1.6m (5.2 ft.), 2.0m (6.6 ft.) and 4.0m (13.1 ft.)).

Figure 7A-2 through Figure 7A-4 found in Appendix 7.2, present the ground settlement profiles for the considered depths of cover and volume losses. Each figure consists of two graphs - one that shows the horizontal and vertical settlement in equal scales and a second which magnifies the vertical settlement by a factor of ten (10) for clarity.

The predicted trough profile presents a gradual non-linear profile that can be expected in the event of total subsidence of a Permanently Deactivated pipeline. The width of the subsidence trough is predicted to be significantly greater than the depth, as seen in the settlement profiles in the aforementioned Appendix 7.2. For example, considering the worst case subsidence profile for total subsidence of a 34-inch pipe, at 0.6 m (2.0 ft.) depth of cover, the peak depth is predicted to be 6.8 inches, whereas the full width of the profile spans nearly 27 feet. This would indicate that for a crossing where the Permanently Deactivated pipeline is perpendicular to a road crossing, for example, the trough width would be parallel to the direction of the road, and the maximum predicted settlement of 6.8 inches would be distributed over approximately 27 feet of the road length in a gradual profile similar to that shown in Appendix 7.2.

The largest magnitude of subsidence predicted for a 34-inch pipeline at a depth of cover 0.6 m (2 ft.) was approximately 6.8 inches, decreasing to 4.7 inches of subsidence at 2 m (6.6 ft.) of cover, as shown in Tables 4-6 through 4-8. This analysis assumes a scenario where there is complete 100% soil infill of the pipe through either complete collapse of the pipe wall or total degradation of the pipe steel. Reviewing the Depth of Cover Survey from 2008, it can be seen that less than 1% of the line has a depth of cover equal to or less than 0.9 m (3.0 ft.), and over 50% of the line has a depth of cover greater than 1.2 m (3.9 ft.). This would indicate that the magnitude of subsidence considering complete loss of pipe volume and 100% infill is expected to be approximately 6 inches or less for the majority of the Permanently Deactivated Line 3.

In agricultural areas, the effect of subsidence due to the eventual decomposition of the pipeline will likely be minimized as a result of regular farming activity. Any cumulative low spots will be identified by Enbridge depth of cover surveys and mitigated.

Table 4-6: Settlement at 100% Volume Loss

Prediction with Assumed Volume Loss of 100%					
Depth of Cover		**Peak Subsidence**		**Half width of significant settlement trough**	
(m)	(ft.)	(m)	(in.)	(m)	(ft.)
0.6	2.0	0.1725	6.8	1.36	4.5
1.2	3.9	0.1450	5.7	1.62	5.3
1.6	5.2	0.1310	5.2	1.79	5.9
2	6.6	0.1195	4.7	1.96	6.4
4	13.1	0.0831	3.3	2.82	9.3

Table 4-7: Settlement at 50% Volume Loss

Prediction with Assumed Volume Loss of 50%					
Depth of Cover		**Peak Subsidence**		**Half width of significant settlement trough**	
(m)	(ft.)	(m)	(in.)	(m)	(ft.)
0.6	2.0	0.0863	3.4	1.36	4.5
1.2	3.9	0.0725	2.8	1.62	5.3
1.6	5.2	0.0655	2.9	1.79	5.9
2	6.6	0.0598	2.4	1.96	6.4
4	13.1	0.0415	1.6	2.82	9.3

Table 4-8: Settlement at 25% Volume Loss

Prediction with Assumed Volume Loss of 25%					
Depth of Cover		**Peak Subsidence**		**Half width of significant settlement trough**	
(m)	(ft.)	(m)	(in.)	(m)	(ft.)
0.6	2.0	0.0431	1.7	1.36	4.5
1.2	3.9	0.0362	1.4	1.62	5.3
1.6	5.2	0.0328	1.3	1.79	5.9
2	6.6	0.0299	1.2	1.96	6.4
4	13.1	0.0208	0.8	2.82	9.3

4.3.1.15 Crossings

The issue of subsidence at crossings is considered when identifying areas of potential risk. Subsidence and structural integrity are not easily predicted on a universal scale; rather, they are a function of site specific corrosion properties, soil mechanics and classification, loading impacts, pipeline depth and other factors. Of particular importance are the terms contained in agreements relating to the crossings of railways, primary and secondary highways, roads, other pipelines, power lines, and communication lines, and the conditions they may place on the deactivation process.

Predicted subsidence profiles have been introduced in section 4.3.1.14 based on assumed depths of cover (Table 4-6 through 4-8). However, with respect to crossings, it should be noted that the depth of cover will be generally greater than those presented in the subsidence profiles due to current installation practices and design criteria. It can therefore be presumed that the extent of subsidence will be less than that shown in Table 4-6 through 4-8.

While not applicable at the time of construction for Line 3, as a reference CFR Part 195.248 dictates depth of cover based on installation location, as seen in Table 4-9 below.

Table 4-9: Cover Over Buried Lines

Location	**Cover (in)**	
	Normal Excavation	Rock Excavation
Industrial, commercial, and residential areas	36	30
Crossing of inland bodies of water with a width of at least 100 feet (30 millimeters) from high water mark to high water mark	48	18
Drainage ditches at public roads and railroads	36	36
Deepwater port safety zones	48	24

Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water	36	18
Other offshore areas under water less than 12 ft (3.7 meters) deep as measured from mean low water	36	18
Any other area	30	18

Unfortunately, guidance is not presently available in the industry for establishing tolerable subsidence limits; the information available instead defers to a risk=-based decision process to support appropriate actions for a specific pipeline.[1]

Table 4-10 is a preliminary summary of the Line 3 crossings identified, and details will be verified during detailed engineering.

Table 4-10: Preliminary Summary of Line 3 Crossings

Crossing Type	Number of crossing type
Roads	**297**
Highway	22
County, City, Township	275
Other (Trail)	**1**
Railroad	**17**
Active	15
Inactive	2

Ground-truthing will occur early during detailed engineering to identify and confirm the number and location of highway and railway crossings. Environmental impacts of treatment of specific crossing locations will be permitted with any applicable federal, state, and local permit requirements.

The crossing methods described below may be further refined upon completion of consultations and final agreements with third parties.

4.3.1.16 Railway

Though both corrosion degradation and structural integrity are believed to not be of concern for decades due to the higher loading produced by rail cars, the grouting of railroad crossings is being evaluated. Enbridge will consult with all railroad authorities in order to determine course of action for all active and inactive railroad crossings.

Ground subsidence due to corrosion and pipe collapse has been shown to be a time dependent failure mode. Specifically, this means that possible subsidence due to pipe or casing degradation would likely occur gradually with time, and therefore monitoring with appropriate intervals is considered an effective response to mitigating the risk. Detailed calculations and estimates of the proposed time to failure will be used as guidance for establishing the inspection intervals.

Based on current information, there are 15 active railway crossings, the majority of which are cased. Given the predicted corrosion rates on Line 3, the corrosion and the structural integrity model results shown in Figure 4-14 predict that the Permanently Deactivated Line 3 will maintain its load bearing capacity until significant general corrosion (approximately 37% equivalent general wall loss, for the full circumference of the pipe) has occurred for a depth of cover of approximately 3.9 feet. Based on the 2008 depth of cover survey, it is expected that all railway crossings will have depth of cover greater than 3.9 feet, but this will be verified during detailed engineering. As large scale general corrosion has not been identified, as addressed in Section 4.3.1.12, total subsidence is not expected to occur.

4.3.1.17 Roads

Due to lower loading considerations and continued third-party maintenance programs, grouting will not take place at road crossings. In an effort to minimize environmental impacts, Enbridge will monitor these crossings to ensure integrity is maintained and will consult with the appropriate road authorities as required.

4.3.1.17.1 Primary Highways

The pipe collapse model presented in Section 4.3.1.11 predicts that all depth of cover analyzed would have sufficient structural integrity to prevent collapse due to HS20 Highway loads, simulating a 20-ton truck traffic load, until significant general corrosion (at least 45% equivalent general wall loss, for the full circumference of the pipe) has occurred. As large scale general corrosion has not been identified, as addressed in Section 4.3.1.12, total subsidence is not expected to occur.

4.3.1.17.2 Secondary Highways, Rural Municipality, and Other Roads

The reduced traffic frequency for secondary highways and roadways further diminishes the likelihood of subsidence at road level caused by pipe collapse. The continued application of CP and standard monitoring practices are appropriate to manage these crossings.

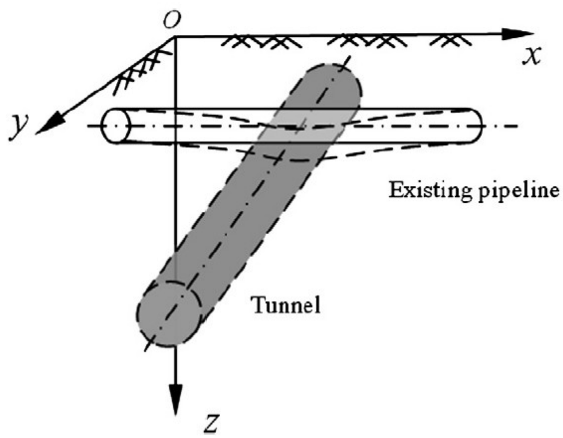
4.3.1.18 Utility Crossings

The CEPA Abandonment Matrix recommends abandonment in-place with special treatment for utility crossings when the pipe diameter is greater than 26 inches. The risks to utilities from pipe removal include the possible loss of support and/or interference with the operation of the utility (i.e., due to third party damage, restricted access, etc.).

Enbridge's proposal is to Permanently Deactivate these crossings in-place subject to a technical risk assessment of utility crossings. Depending upon the result of that assessment, Enbridge may apply special treatment on a case-by-case basis. The primary risk for utility crossings associated with a Permanently Deactivated in-place pipeline is the potential for void formation, which could lead to an unsupported length of pipeline or cable, or displacement due to ground subsidence, as illustrated in Figure 4-20.

Figure 4-20: Representation of Tunneling Possible for Crossing Utility

(Reproduced from *Boundary element model for analysis of the mechanical behavior of existing pipelines subjected to tunneling-induced deformations*)[22]



4.3.1.19 Casings

The benefits of casings with respect to structural integrity of the pipeline and any cased crossing locations should be noted. Presently, the structural integrity models presented were based solely on the capacity of the carrier pipe, and conservatively ignored any benefits of the casings.

The primary benefit of casings, with respect to structural integrity and loading capacity are that casing pipes, while intact, will provide additional structural support to the Permanently Deactivated carrier pipe. Secondly, from a risk perspective, casings will provide a secondary barrier to failure, either by corrosion or structural collapse, meaning that both the casing pipe and the Permanently Deactivated carrier pipe would have to fail prior to any substantial ground subsidence at a cased crossing. The nominal wall thicknesses for casings vary but are typically reported to be greater than ~.5 inches.[19]

It has been shown that subsidence due to pipe or casing corrosion and possible pipe collapse is a long-term time-dependent risk. Specifically, this means that possible subsidence due to pipe or casing degradation would occur gradually with time, and can be monitored or observed so that appropriate corrective action can be taken prior to significant subsidence.

Of primary concern for casings is that they are generally not coated, and therefore subject to general corrosion. Additionally, there is potential for shielding of CP from the carrier pipe if not properly maintained.

4.3.1.20 Summary and Conclusions – Structural Integrity and Subsidence

The primary conclusions of the analyses provided are as follows:

- Based on the PTAC corrosion rate curves presented, and comparison with historical ILI data for Line 3, the estimated time to through wall penetration was calculated to be between 25 to 50 years from 2011.
- The results of the PTAC model considering generalized wall loss for the Permanently Deactivated Line 3 indicate predicted minimum time to collapse as 87 years, with estimates well above 1,000 years based on the variety of soil conditions as described in Section 4.3.1.7.
- The results of the PTAC model considering pitting corrosion indicate the Permanently Deactivated Line 3 will maintain the majority of its structural strength until greater than 30% of the pipe's circumference is lost due to coalescing of perforations.
- The maximum subsidence predicted considering 100% volume loss of the pipe, complete infill, and 2.0 feet depth of cover was 6.8 inches.
- The maximum subsidence predicted considering 50% volume loss of the pipe, complete infill, and 2.0 feet depth of cover was 3.4 inches.
- Predicted subsidence profiles indicate a gradual sloping surface profile, which would create minimal disturbance to surface profile for the depths predicted.

4.3.2 Mitigation

As stated above, subsidence due to pipe or casing corrosion and possible pipe collapse is a long-term time-dependent failure mode. Numerous calculations are referenced estimating the time to collapse as being many decades, or more likely centuries.[1,3,6,13] Conservative calculations based on the PTAC collapse model for a 34-inch pipeline, similar to Line 3, predict the minimum time to collapse as 87 years at railway crossings, and with estimates significantly greater than 1,000 years based on the variety of soil conditions as described in Section 4.3.1.7.

To address the risks associated with long-term corrosion and possible ground subsidence, Enbridge will:

- continue to monitor the Permanently Deactivated pipeline as part of its ongoing Operations and Maintenance programs;

- survey, assess, and mitigate the depth of cover over the Permanently Deactivated pipeline in accordance with O&MM and Enbridge's PDMP;
- monitor and apply the CP in accordance with Enbridge O&MMs and CCG; and
- perform ground-truthing to identify and confirm the number and location of crossings.

4.3.2.1 Monitoring & Maintenance

Enbridge will continue to monitor the Permanently Deactivated pipeline as part of its ongoing Operations and Maintenance programs. Certain applicable monitoring procedures currently practiced on active pipelines will be extended to the Permanently Deactivated pipeline, in order to address the risks identified in Section 3. Operations and Maintenance activities include:

- completing pipeline inspections during patrols;
- assessing areas of potential geotechnical threats;
- maintaining pipeline signage;
- performing depth of cover surveys; and
- monitoring the CP system.

The Permanently Deactivated pipeline will also remain a part of Enbridge's programs for damage prevention and safe work practices, which include:

- continuing Enbridge's public awareness program; and
- ensuring ground disturbance activities by the Company or third parties in the vicinity of the pipeline in accordance with Enbridge construction specifications and O&MMs. Typical requirements are:
  - specifying safe work distances during excavation;
  - surface locating and identifying the pipeline;
  - ensuring pipeline is crossed in a safe manner and applying temporary ramps or matting when required; and
  - verifying that construction activities do not negatively impact the integrity of the pipeline or its CP system.

Enbridge periodically reviews and revises its standards and procedures to incorporate regulatory and legislative changes, updated safe work practices and industrial knowledge, and new technology. As such, the on-going monitoring of the Permanently Deactivated pipeline will progress in the same manner as Enbridge's active pipelines.

4.3.2.2 Right-Of-Way Patrols, Geotechnical Threat Assessments and Signage

To protect the public in proximity of the pipeline, the environment, and the integrity of the pipeline, the ROW is monitored by:

- patrolling the entire ROW plus the adjacent land;
- documenting and assessing abnormal conditions or activities on or adjacent to the ROW;
- assessing areas of potential geotechnical instability; and
- inspecting and maintaining ROW signs and markers.

ROW monitoring is completed in accordance with Enbridge O&MM.

ROW patrols are completed by qualified individuals to identify abnormal surface conditions or activities on or adjacent to the ROW using methods of walking, driving, flying or other appropriate means, periodically. Any abnormal condition or activity will be recorded. Enbridge will complete additional investigations when warranted. These investigations include documenting the location and condition of exposed pipe, and assessing the effects of unsupported spans, atmospheric corrosion, and third party damage on the pipeline. Remediation activities are planned based on the risk associated with the abnormality. Remediation options include, but are not limited to:

- on-going monitoring;
- improving community awareness; or
- providing additional depth of cover, buoyancy control, pipeline protection, cladding, matting, or drainage control.

The Enbridge mainline is assessed for geotechnical threats such as areas of potential slope stability or erosion concerns. These areas, when identified, undergo a site-specific assessment which may recommend more frequent or detailed on-site monitoring. Enbridge's plan to leave the Permanently Deactivated pipeline in-place will minimize the risk of erosion caused by construction activities because the vast majority of the ROW will remain undisturbed. With no disturbance, the permanently deactivated Line 3 ROW will have the same risk for erosion as the surrounding ROW for the active pipelines. In areas where excavation may occur, site-specific erosion plans will be developed, and all work will be performed in accordance with the Project's Environmental Protection Plan.

Warning signs and line markers are located in key areas to promote awareness in the vicinity of the pipeline. These signs will be visually inspected during regular patrols and, when required, the key information on the signs will be updated. Signage is also checked annually to ensure signs are not missing, vandalized, or damaged, and are visible from appropriate roadways and railways.

4.3.2.3 Pipeline Depth Monitoring Program

Depth-of-cover surveys utilize electromagnetic line locating equipment or equivalent technology to accurately locate and record the depths for each pipeline in the ROW. The depth of cover over the Permanently Deactivated pipeline will be surveyed, assessed, and mitigated in accordance with the O&MM. The depth of cover survey program for the Permanently Deactivated pipeline will be completed at least once every ten years. The frequency for the depth of cover survey program may be reduced for portions of the pipeline based on internal risk assessments.

The depth of the pipe will be measured and recorded at predefined intervals down the ROW. Additional measurements will be taken on either side of a location with insufficient depth of cover. Physically probing for pipeline depth is used to validate non-intrusive depth measurements.

If the measured depth of cover of the Permanently Deactivated pipeline poses a risk to public safety or the environment, a risk analysis will be conducted to assess whether mitigative action is required. This risk analysis will consider land use, underground structures in close proximity, and/or adverse conditions that may prevent the maintenance of such cover. The risk assessment will determine if further action is required, such as:

- adding soil over the pipeline;
- lowering the pipeline;
- developing new agreements to restrict land use with the appropriate stakeholders; or
- installing mechanical protection over the pipeline.

4.3.2.3.1 Exposed Pipe

Currently, locations where pipe is exposed are identified through aerial patrol as well as by performing field depth of cover surveys. The areas of exposed pipe are reviewed by various internal stakeholders through a risk assessment, to identify priority and necessary remedial actions.

A review of the exposed pipe, depth of cover data and pipeline crossing features has been completed to identify areas that may be subject to loss of cover once the pipeline is purged.

Enbridge continues to monitor high risk areas and prescribes the appropriate course of action in the event additional pipe becomes exposed.

Following completion of deactivation activities on Line 3, if newly exposed pipe is discovered, each site will be reviewed by the following stakeholder representation: ROW/permitting agent(s), environmental lead and relevant agency, operations representative, and Enbridge Pipeline Integrity representative. Each will have a specific responsibility when considering the completion of site-specific mitigation efforts:

- The ROW agent will work with landowners or pertinent jurisdictional authorities impacted;

- The Environment Lead will need to complete a review with those agencies having jurisdiction;
- The Operations representatives will need to be engaged to review the workspace and any potential impacts to the operation of adjacent lines; and
- The Enbridge Pipeline Integrity representative should review and address risks brought from an Enbridge systems perspective.

The aforementioned stakeholder review will be used to identify inputs to a risk assessment matrix. Mitigation methods will be chosen upon completion of the risk review with the following potential actions:

- Pipe Removal: Removal of pipe will be dependent on site-specific conditions and will likely produce the highest environmental impacts, risk to adjacent lines and complications with regards to constructability.
- Grouting: grouting as a mitigation technique will have permanent results if the pipe re-settles and will have a lower environmental impact and lower risk to adjacent lines as compared to full pipe removal. Grouting lengths may be limited and therefore pose effective installation risk during construction. Grouting for buoyancy mitigation is meant to re-settle the pipeline, with the intent of eliminating positive buoyancy.
- Continued monitoring: with continued monitoring, there is no present impact to either Line 3 or the adjacent lines. The company will continue to monitor the high risk areas and mitigate as necessary.

4.3.2.4 Cathodic Protection

There are currently 82 Impressed Current CP (ICCP) Systems along the US portion of the route that actively function to mitigate threats of external corrosion on the entire mainline system. Additionally, there exists upwards of 90 bonds connecting Line 3 and adjacent pipelines, as well as an unknown number of below grade bonds, the locations of which may not be known.

In evaluating how to manage the existing cathodic protection (CP) system, the following were assessed: regulatory requirements and commitments, Enbridge's Operating and Maintenance Procedures, economic impact, and external corrosion risks associated with potential changes to the CP system. Based on this analysis, it was determined that the CP system will remain in place.

4.3.2.4.1 <u>Maintaining the Active CP System</u>

In keeping the existing CP system in place, there are effectively no changes from current CP work practices within the EEP corridor due to the operational status of Line 3. In any areas where Line 3 is segmented, new bonding cables will be installed to ensure electrical continuity remains across the pipeline, to maintain cathodic protection along the existing Line 3.

Environmental impacts of CP system maintenance will be permitted in accordance with any applicable federal, state, and local permit requirements.

In a multiple pipeline ROW, it is common to install bonds to maintain electrical continuity of the pipelines for CP operation. Bonds help to distribute CP current evenly through the pipeline ROW as well as mitigate stray current interference amongst neighboring pipelines. To ensure electrical continuity, bonds will be installed at locations where Line 3 is non-contiguous. The installation of bond cables will be completed in accordance with Enbridge D04-101 (2015), "Cathodic Protection – Mainline." Bond cable sizing will be determined based upon the current carrying capacity but will be no smaller than #4 AWG stranded copper cable. In addition to the bond cables installed, it is recommended that Test Lead cables are installed for future monitoring. The intention is to install bond cables on each Enbridge pipeline at segmentation locations. All cables will be terminated in an above grade junction box at a location that minimizes impacts to land use.

In some cases, it may be required to relocate a bond box to a suitable location for the above grade appurtenance. When able, these locations will remain within the existing Enbridge ROW, however they may be situated at the nearest tree line, fence line, or edge of a roadway ditch. As the project develops, site specific drawings may be required for cases where bond boxes cannot be placed at the segmentation location and will be addressed on a case-by-case basis.

4.3.2.4.2 Monitoring of CP System

In the short-term, Operations would continue to monitor and maintain the CP system to meet requirements for all pipelines along the EEP corridor. In the long-term, as CP systems become depleted and protective coatings deteriorate or change, new design and monitoring efforts will need to be implemented to maintain system integrity. As the coating quality on Line 3 degrades, an increased current requirement will be needed to mitigate external corrosion, ultimately increasing the costs associated with operating the CP system, both electrically and through the installation of new CP groundbeds.

The following programs or monitoring methods are currently undertaken by Enbridge to ensure the integrity of the CP systems:

- AC-DC Structure to Soil Potential Monitoring Program: Regularly scheduled monitoring to verify adequate cathodic protection levels on all pipelines and facilities through field surveys or remote monitoring;
- Bonding Inspection Program: Regularly scheduled monitoring of critical and non-critical bonds through field surveys or remote monitoring;
- Rectifier Operation Monitoring: Regularly scheduled monitoring of cathodic protection system rectifiers and related equipment to ensure correct operation of the cathodic protection system through field surveys or remote monitoring equipment;
- Close Interval Survey Program: Regular scheduled close interval surveys to provide a cathodic protection (CP) profile of the pipeline. An initial survey is completed when the

pipeline is put into operation and additional surveys are completed if operating conditions change;

- CP Coupon Monitoring Program: Regular inspection of CP coupons to obtain field or remote measurements to monitor current densities and induced resistance free reading; and
- Atmospheric Pipe Inspection Program: Regularly scheduled visual inspection of all above grade piping, including exposed piping, for atmospheric corrosion.

While the proposed Permanent Deactivation Plan involves maintaining CP as practical to extend the life as a load bearing structure, it is recognized that, "…in the long term, any pipeline left in-place would eventually degrade to the point that a void exists in the ground".[2] The terms, "long-term" and "eventually", cited here were intentionally vague, as they refer to site specific conditions. The analyses presented have shown that this "long-term" may be in the order of centuries or more. Specifically, this means that possible subsidence due to pipe or casing degradation or collapse would occur gradually with time, and therefore on-going monitoring with appropriate intervals is considered an effective response to mitigating the risk. Detailed calculations and estimates of the proposed time to failure will be used as guidance for establishing the inspection intervals during detailed engineering.

5 CONCLUSION

Enbridge's Line 3 Permanent Deactivation Plan is based upon engineering and risk assessments which identified the technical risks and mitigation measures associated with the Permanently Deactivated pipeline. As part of this assessment, Enbridge assessed the relative risks of removing the pipeline and Permanently Deactivating it in place. Removing the 282 miles of existing Line 3 would create a significant risk to other operating pipelines and additional impacts to the environment, land use, and public safety similar to and exceeding those related to constructing a new pipeline project. Based on the results of the risk assessment, Enbridge believes that deactivating a pipeline in place minimizes and/or eliminates unnecessary impacts to the environment, landowners, and the state of Minnesota.

Enbridge's Permanent Deactivation Plan was designed to Permanently Deactivate the pipeline in a way that minimizes risks to public safety, the environment, and current land use. In summary, the scope of the Plan includes:

1. Purging the oil;
2. Cleaning of the pipeline;
3. Isolating the pipeline from specific infrastructure which is actively transporting oil;
4. Further segmentation of the pipeline, as needed, including completing all required remediation at roads, railroads, waterbodies, or any other permitted crossing in consultation and coordination with that crossing's authority; and

5. Continue to monitor the existing right-of-way (ROW) to identify, assess, and appropriately mitigate apparent or emerging risk to public safety, the environment, or current land use caused by the Permanently Deactivated pipeline. As part of the ongoing maintenance and monitoring, continue to apply cathodic protection (CP) until such time that it is ineffective or otherwise detrimental.

These measures will protect the environment and human activity by minimizing risks related to soil and water contamination, water conduits, and subsidence. This Permanent Deactivation Plan will also avoid the unnecessary risks and impacts related to pipeline removal.

6 REFERENCES

1. CEPA Pipeline Abandonment Assumptions – Technical and Environmental Considerations for Development of Pipeline Abandonment Strategies, September 2006 – April 2007.
2. National Energy Board, Decommissioning Provisions under the Onshore Pipeline Regulations, 1999. Found in: National Energy Board Processing Plant Regulations and Guidance Notes and Exemption Order – Decommissioning provisions. National Energy Board Files Ad-GA-RG-OPR 01 and Ad-GA-RG-PPR 01, October 2, 2008.
3. National Energy Board Pipeline Abandonment – A Discussion Paper on Technical and Environmental Issues, 1996.
4. Canadian Standards Association Standards Z662-11, Oil and gas pipeline systems, Canadian Standards Association, Published June 2011, reprinted January 2012 with revisions.
5. National Energy Board, Background Paper on Negative Salvage Value, September 1985.
6. DNV GL, Pipeline Abandonment Scoping Study, EP028844, Reg No. ENACA855, Prepared for the National Energy Board, November 2010.
7. Report 2013-B: Pipeline Performance in Alberta, 1990-2012, Alberta Energy Regulator (AER), http://www.aer.ca/documents/reports/R2013-B.pdf/.
8. CONCAWE, Performance of European Cross-country Oil Pipelines, Statistical summary of reported spillages in 2010 and since 1971, Brussels, December 2011, http://www.concawe.org/.
9. Canadian Guidelines for the Management of Naturally Occurring Radioactive Materials (NORM). Prepared by the Canadian NORM Working Group of the Federal Provincial Territorial Radiation Protection Committee, Health Canada, 2007.
10. Reference Method for the Canada-Wide Standard for Petroleum Hydrocarbons in Soil - Tier 1 Method, Canadian Council of Ministers of the Environment, 2001.
11. Code of Practice for the Release of Hydrostatic Test Water from Hydrostatic Testing of Petroleum Liquid and Gas Pipelines, Government of Alberta, made under the Environmental Protection and Enhancement Act, 1999.

12. Industrial Pigging Technology; Gerhard Hiltscher, Wolfgang Muhlthaler, Jorg Smits; Wiley- VCH 2003; Page 161 Section 10.3.5 Residual Film of the Pigged Pipe.
13. DNV GL Final Report, Understanding the Mechanisms of Corrosion and their Effects on Abandoned Pipelines, TAOUS813COSC (PP079627), prepared for the Pipeline Abandonment Research Steering Committee. The report has been completed for PTAC, is currently undergoing peer review and is intended to be published.
14. Analysis of Pipeline Steel Corrosion Data from NBS (NIST) Studies Conducted between 1922-1940 and Relevance to Pipeline Management, Richard E. Ricker, NISTIR 7415, NIST May 2007.
15. "External Corrosion Direct Assessment Methodology," NACE SP0502-2008, March 20, 2008.
16. "Pipeline External Corrosion Direct Assessment Methodology." ANSI/NACE SP0502-2010. December 3, 2010.
17. Velazquez, J.C., Valor, A., Caleyo, F. and Espina, J.H., "Study Helps Model Buried Pipeline Pitting Corrosion," Oil and Gas Journal – Corrosion, 2009.
18. Gas Research Institute State-of-the-Art for the Use of Anti-Corrosion Coatings on Buried Pipelines in the Natural Gas Industry, April 1992.
19. "Cased Pipe Corrosion Rate Estimation." DNV and NYSEARCH/NGA, ANEUS813KKRA (EP006065). June 3, 2011.
20. Guidelines for the Design of Buried Steel Pipe, (Live Loading from American Lifelines Alliance) American Society of Civil Engineers, July 2001.
21. "Statistical Analysis of External Corrosion Anomaly data of Cased Pipe Segments", prepared for the INGGA Foundation, Inc, by Southwest Research Institute.
22. Zhiguo Zhang, Maosong Huang, "Boundary element model for analysis of the mechanical behavior of existing pipelines subjected to tunneling-induced deformations" Computers and Geotechnics, Vol. 46, November 2012, pp 93-103.
23. American Society of Mechanical Engineers, Power Piping: ASME Code for Pressure Piping, B31.1, 2007 ed.
24. Water Act, current as of March 29, 2014, Province of Alberta, 2000, Edmonton, AB.
25. The Water Power Act, revised August 12, 2013, Province of Saskatchewan, 2013, Regina, SK.
26. The Water Rights Act, current as of August 22, 2014, Province of Manitoba, 2006, Winnipeg, MB.
27. Texas Department of Transportation Construction and Materials Tips, Ground Penetrating Radar (GPR), September 2010, <https://ftp.dot.state.tx.us/pub/txdot-info/cst/tips/ subsurface_voids.pdf>, July 23, 2014.
28. Wong, E., Sasaki, G. and Harrison, J., "An Approach to Sinkhole Prevention on Post Pipeline Construction at Trenchless Road Crossings," IPC2012-90510, 2012.
29. National Energy Board Onshore Pipeline Regulations, 1999, National Energy Board, Calgary, AB, current to July 22, 2014.
30. Filing Manual. Inclusive of Release 2014-01 (January 2014). National Energy Board, Calgary, AB, 2014.
31. Canada-Wide Standards for Petroleum Hydrocarbons in Soil, Canadian Council of Ministers of the Environment, 2008.

32. Canadian Soil Quality Guidelines – Carcinogenic and other polycyclic aromatic hydrocarbons (Environmental and Human Health Effects), Canadian Council of Ministers of the Environment, 2010.
33. Canadian Soil Quality Guidelines for the Protection of Environmental and Human Health – Polychlorinated Biphenyls (Total), Canadian Council of Ministers of the Environment, 1999a.
34. Canadian Soil Quality Guidelines for the Protection of Environmental and Human Health – Ethylbenzene, Canadian Council of Ministers of the Environment, 2004.
35. Canadian water quality guidelines for the protection of aquatic life. In: Canadian environmental quality guidelines, 1999, Canadian Council of Ministers of the Environment, 1999b, Winnipeg, MB.
36. Canadian water quality guidelines for the protection of agricultural water uses. Canadian environmental quality guidelines, 1999, Canadian Council of Ministers of the Environment, 1999c, Winnipeg, MB.
37. Recreational water quality guidelines and aesthetics. In: Canadian environmental quality guidelines, 1999, Canadian Council of Ministers of the Environment, 1999d, Winnipeg, MB.
38. El-Taher, M. and Moore, I.D, "Effects of Wall Corrosion and Backfill Erosion on the Strength of Deteriorated Metal Culverts," International No-Dig 2011, 29th International Conference.
39. External Corrosion of Oil and Natural Gas Pipelines, John A. Beavers and Neil G.Thompson, CC Technologies. 2006 ASM International. All Rights Reserved, ASM Handbook, Volume 13C, Corrosion: Environments and Industries (#05145)
40. Peck, B. "Deep Excavations and Tunneling in Soft Ground." Proceedings of 7th International Conference on Soil Mechanics and Foundation Engineering. 1969
41. Schmidt, B. "Settlements and Ground Movements Associated with Tunneling in Soil", Ph.D Thesis, University of Illinois, 1969.
42. Mair, R.J. "Centrifugal Modeling of Tunnel Construction in Soft Clay," Ph.D. Thesis, Cambridge University, 1979.
43. ASM Handbook Volume 13C: Corrosion: Environments and Industries, Editor: Stephen D. Cramer and Bernard S. Covino, Jr., ISBN 978-0-87170-709-3
44. "ARCTIC PIPELINE DESIGN CONSIDERATIONS", ASME International Conference on Offshore Mechanics and Arctic Engineering, OMAE2008-57802
45. Abed-Alkareem, S.S., "Power Plant Waste Heat Utilization for Soil Heating using Subsurface Pipes," Journal of Engineering and Development, Vol. 16, No. 1, March 2012 ISSN 1813-7822

7 APPENDICES

7.1 ENBRIDGE LINE 3 DECOMMISSIONING CLEANING VALIDATION PROGRAM REPORT

Appendix 7.1

Line 3 Decommissioning
Cleaning Validation Program Report

Enbridge Pipelines Inc.
September 4, 2015

Enbridge Pipelines Inc. (Enbridge) conducted a cleaning validation program on a 19.8 km section of the NPS 34 Line 3 that was recently deactivated near Cromer, Manitoba by Enbridge as part of National Energy Board (NEB) filing A50617. This validation program was completed in accordance with NEB filing A64166 as part of Enbridge's application to the NEB for the Line 3 Replacement Program (L3RP).

The cleaning validation program successfully accomplished the following objectives:

1. Develop and execute an economical, reliable, and repeatable cleaning program that could be implemented when decommissioning Line 3,

2. Demonstrate the effectiveness of the program by completing third party testing for residual hydrocarbons in fluid samples of the cleaning solution and water used to clean the pipeline, and

3. Validate that polychlorinated biphenyls (PCB) and naturally occurring radioactive materials (NORMs) are not a risk that requires modification to the decommissioning plan for Line 3 currently filed with the NEB.

The cleaning program consisted of one chemical train (comprised of two 18 m^3 batches of cleaning solution and one 35 m^3 water batch), one rinse train (comprised of three 35 m^3 water batches), and a third train (comprised of a foam pig and scraper pig) to remove residual bulk fluid remaining in the pipeline. Approximately 5 m^3 of cleaning solution was injected in front of the chemical train to lubricate the first pig in the train. A combination of hard brushes, pencil brushes, and scraper pigs were used to scrape the pipe walls and maximize cleaning effectiveness. The objectives each pig and train are outlined in table 1 below.

Table 2: PIG sequence and objectives for chemical train

Pig Train #	Pig Sequence #	Pig Type	Objective
1 - Chemical	1	Spring Loaded Hard Brush Pig	Initial brush pigs were used to scrape the pipe walls to maximum cleaning effectiveness. Aggressive brushes were installed on a spring to provide mechanical cleaning without damaging the pipe wall.
	2	Spring Loaded Hard Brush Pig	
	3	Spring Loaded Pencil Brush Pig	Slightly less aggressive brushes removed residual deposits remaining after the hard wired brushes. The pencil brushes were also spring loaded to avoid excessive scraping of the pipe wall.
	4	Spring Loaded Pencil Brush Pig	
2 - Rinse	5	Scraper Batch Pig	Scraper pigs were used for final scraping of the pipe walls with the polyurethane discs. These pigs removed any debris/contaminants dislodged by the brush pigs in pig train #1, and transported the material in the water batches. The combination of cups and discs provided effective isolation of the rinse batches to prevent bypass of material and, removed most of the fluid from the pipeline.
	6	Scraper Batch Pig	
	7	Scraper Batch Pig	
	8	Scraper Batch Pig	
3 - Foam	9	Foam Pig	Foam pig and Scraper pig used to remove residual free bulk fluid remaining in the pipeline after pig train #2.
	10	Scraper Batch Pig	

Engineering of the cleaning validation program was completed in two phases: laboratory testing of representative pipeline material to determine appropriate chemical selection for the cleaning solution, and hydraulic modeling and design of the cleaning train. Laboratory testing of potential cleaning chemistries was completed using hydrocarbon covered test coupons representative of the worst case scenario for potential pipe wall contamination based on the previous products transported on Line 3. These tests determined that a water-based cleaning formulation in combination with water rinses was most appropriate for cleaning the Line 3 pipeline. The volume of cleaning solution and water were sized based on specific parameters of the Line 3 pipeline segment (i.e. length and diameter). Engineering of the Line 3 cleaning program will consist of the same two phase approach, during which the batch sizes and cleaning chemistry may be subject to change. Figure 1 illustrates the three pig trains employed in the cleaning validation program.

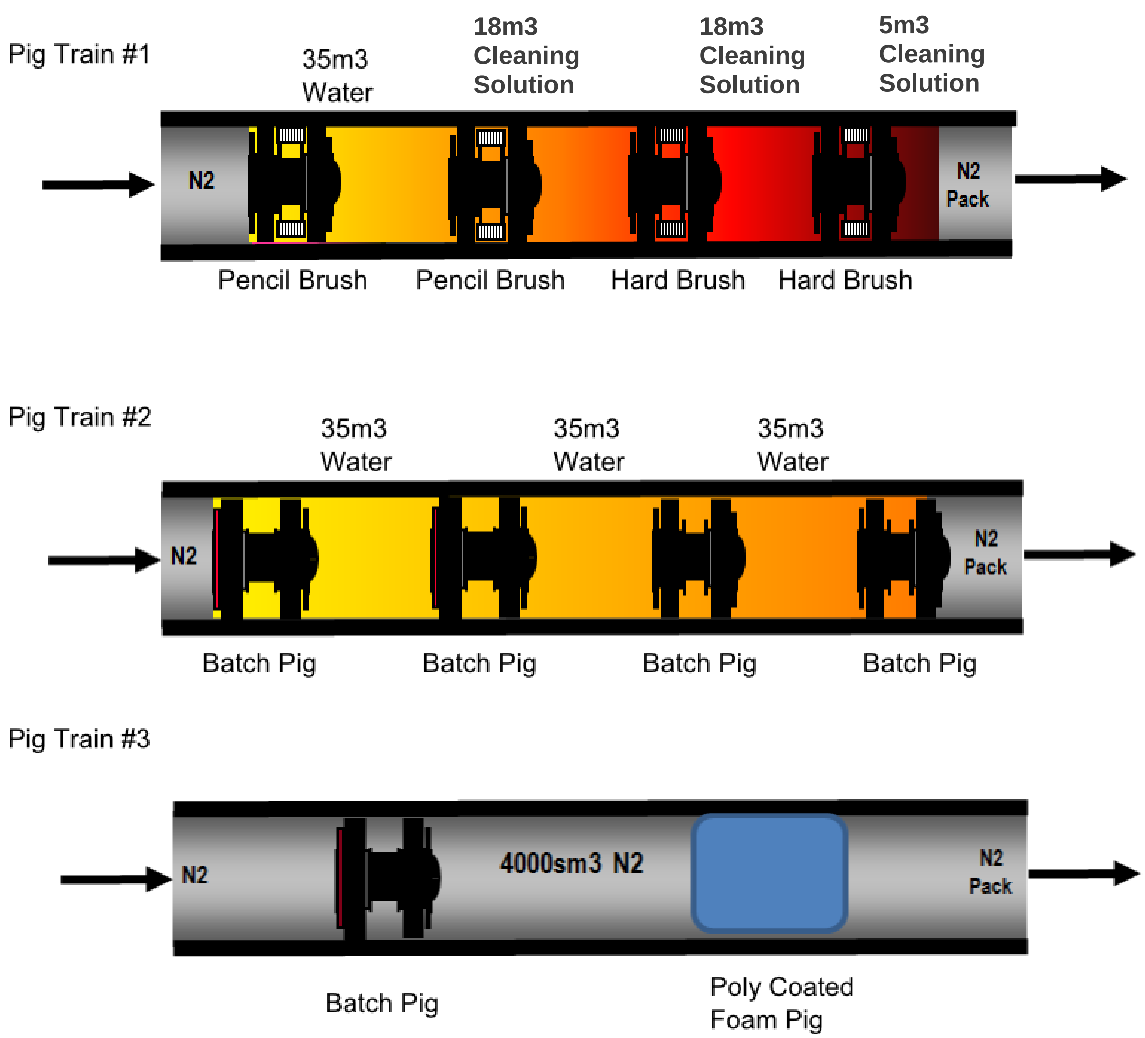


Figure 1: Cleaning validation program pig trains

The execution of the cleaning operation was split into three separate trains due to the size of receiving traps available for the cleaning validation program. The Contractor agreed that the resulting cleanliness for either a combined or split pig train was unchanged provided the fluid volumes, cleaning fluids, and fluid residence times are not altered. Enbridge intends to clean Line 3 in a single operation (one pig train) when decommissioning the remainder of the Line 3 pipeline.

Nitrogen (N_2) was used to propel all pig trains. Nitrogen was chosen as the propellant for this application as its inert properties allow for the safe propulsion of the cleaning train regardless of the residual vapours. Sampling of the lower explosive limit (LEL) completed during the cleaning operation confirmed that compressed air could be utilized safely as an alternative propellent when cleaning the remainder of Line 3 as part of L3RP. The propellant selection for the Line 3 cleaning program will be further evaluated as part of detailed engineering.

All samples collected during the cleaning validation program were submitted to a Canadian Association for Laboratory Accreditation Inc. (CALA) accredited laboratory to provide an unbiased and independent chemical analysis of the effectiveness of the cleaning validation program. The laboratory analysis of the samples collected confirmed that PCB and NORM concentrations were below detectable limits and therefore are not a risk to the decommissioning of the remainder of the Line 3 pipeline..

Samples taken at the discharge of the pipeline demonstrated that the cleaning program developed was effective in removing residual hydrocarbons from the deactivated pipeline. The cleaning and rinse trains were designed to identify possible limitations in cleaning technologies when decommissioning Line 3. Sampling of the water rinse batches indicated a strong downward trend in the concentration of hydrocarbon constituents between rinse batches as shown by Figure 2. The remaining water flush sample concentrations ranged from 108.2 mg/L for the initial sample to 15.54 mg/L for last samples of the final rinse. As the total petroleum hydrocarbon (TPH) concentrations in the water samples produced a statistically significant exponential decay curve with a high degree of confidence, the measured decrease in the TPHs are expected to be repeatable when using similar cleaning methodology, cleaning equipment/materials, and initial conditions on Line 3.

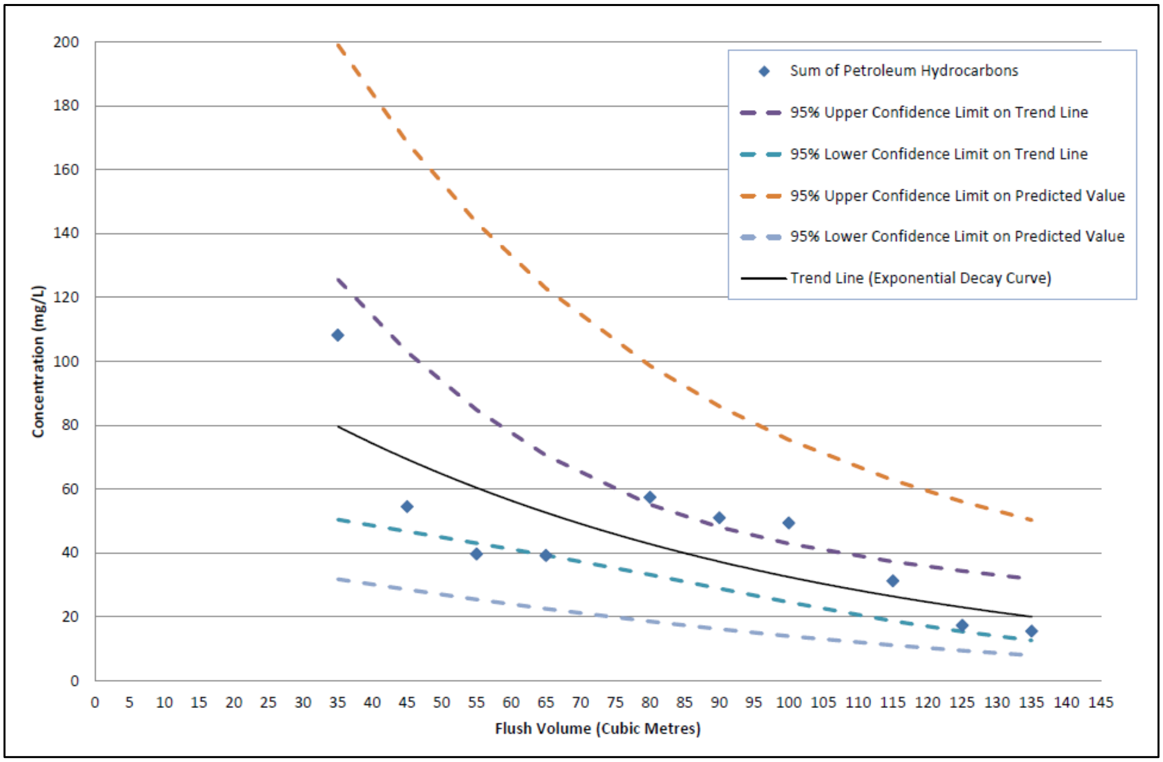


Figure 2: Rinse train sample TPH analysis based on flush volume

Based on the successful execution of the cleaning validation program, the same engineering approach utilized for the cleaning validation program will be implemented to develop the cleaning program to decommission the remainder of Line 3 as per Enbridge's current filing with the NEB for L3RP.

7.2 STRUCTURAL INTEGRITY AND SUBSIDENCE

APPENDIX 7.2

Structural Integrity and Subsidence

SECTION A – SOIL TROUGH SUBSIDENCE PROFILES

This section provides the results and discussions from studies conducted for a series of generalized soil subsidence scenarios. These generalized cases have been assumed to be imposed on the 34-inch OD pipeline. The scenarios considered predictions of settlement profiles (ground subsidence) under 25, 50 & 100% volume loss at various depths of cover (between ground level and crown of the pipe), in which 100% volume loss is the total collapse of the pipeline, with complete soil infill and 25% volume loss represents a partial infill scenario.

Ground subsidence estimations should take into account two different scenarios: following complete infill considering pipe collapse at shallow burial depth, and partial infill due to excessive ovalization and/or finite soil ingression.

Prediction of total ground subsidence, considering complete infill of the pipe volume can be predicted through analogy with tunneling construction. Extensive field measurements (Peck, 1969; Schmidt, 1969; Rankin, 1988; Mair, 2008) have shown that the settlement trough during open-face tunneling construction can be well characterized by the Gaussian distribution curve:

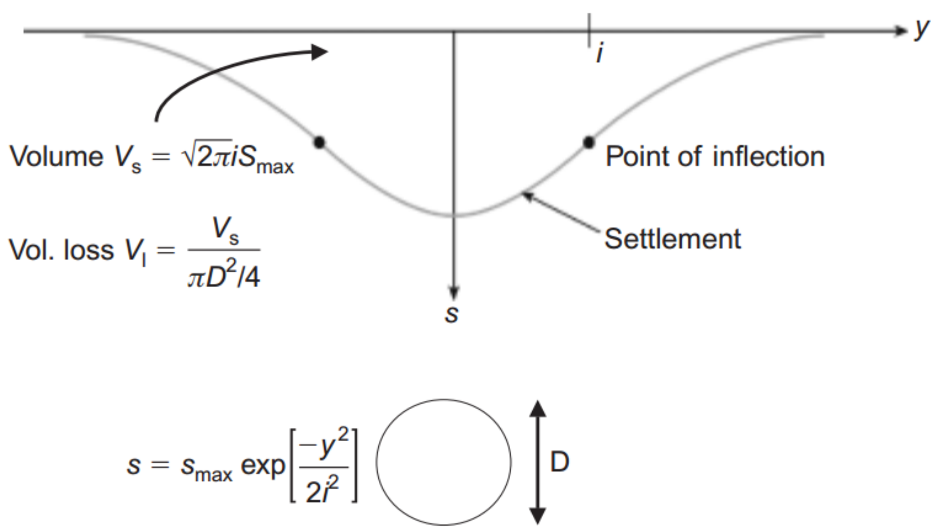
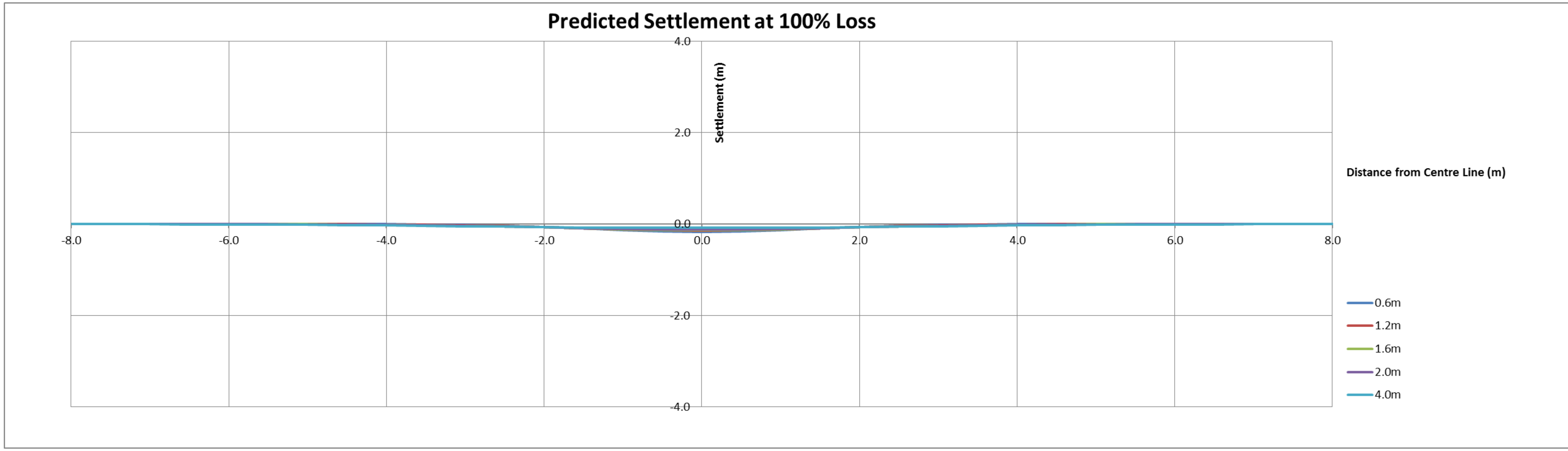


Figure 7A - 1: Generic ground settlement trough considering Gaussian Distribution Curve Method

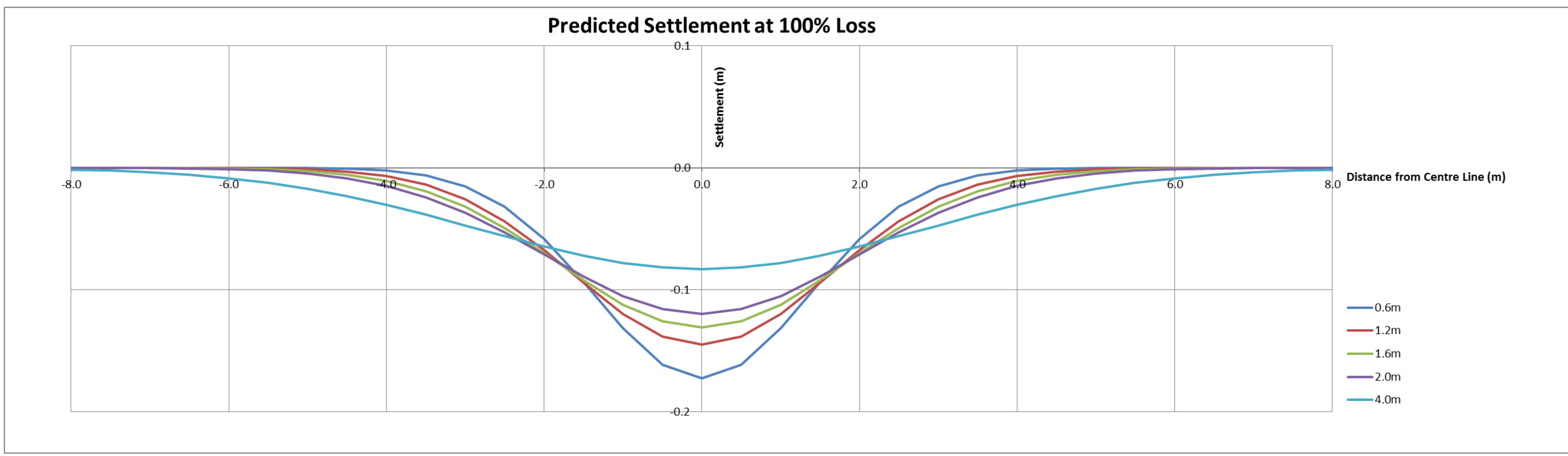
Where *i* describes the characteristic half-width of the settlement trough and is a dependent on the soil cover height and soil type. For this particular case, the exact shape of the Gaussian distribution curve can be estimated based on the particular scenario: total pipeline collapse (V_l = 1), or partial collapse (i.e. excessive ovalization, $0 < V_l < 1$).

Figure 7A - 1 through Figure 7A - 3 shows results from a number of preliminary settlement at different volume loss values (100%, 50% and 25%) and depths of cover to the pipe's crown (assumed at 0.6m, 1.2m, 1.6m, 2.0m and 4.0m). Each figure consists of two graphs - one that shows the horizontal and vertical settlement in equal scales and a second which magnifies the vertical settlement by a factor of ten (10) for clarity.

As expected, the peak subsidence increases with higher volume loss value and shallower depth of cover. The half-width of settlement trough is only dependent on the depth of cover though it is not as linearly increasing with depth of cover as assumed in geometric models presented in PTAC report. The reason is that for pipe embedded at shallower depths, the two models are similar in their predictions but at deeper covers the Gaussian distribution curve introduced in this analysis has been shown to offer a better match to the observed ground settlement data, particularly for tunnels.

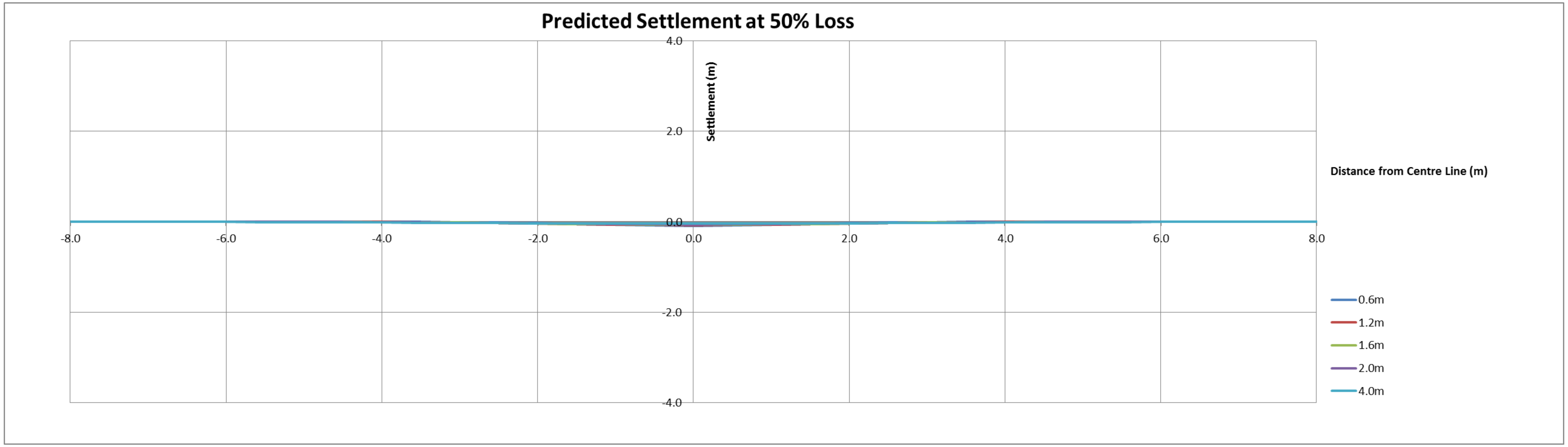


(a)

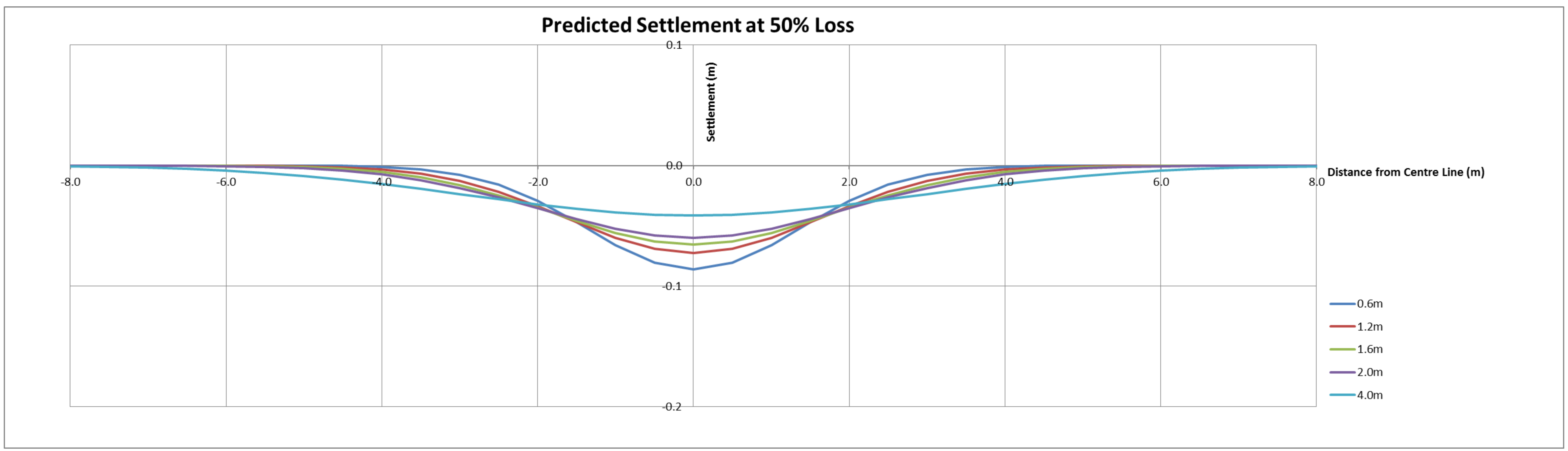


(b)

Figure 7A - 2: Predicted settlement profile at ground level for different depths of cover assuming 100% volume loss (a) equivalent horizontal and vertical scales (b) vertical scale magnified to ten times the horizontal scale

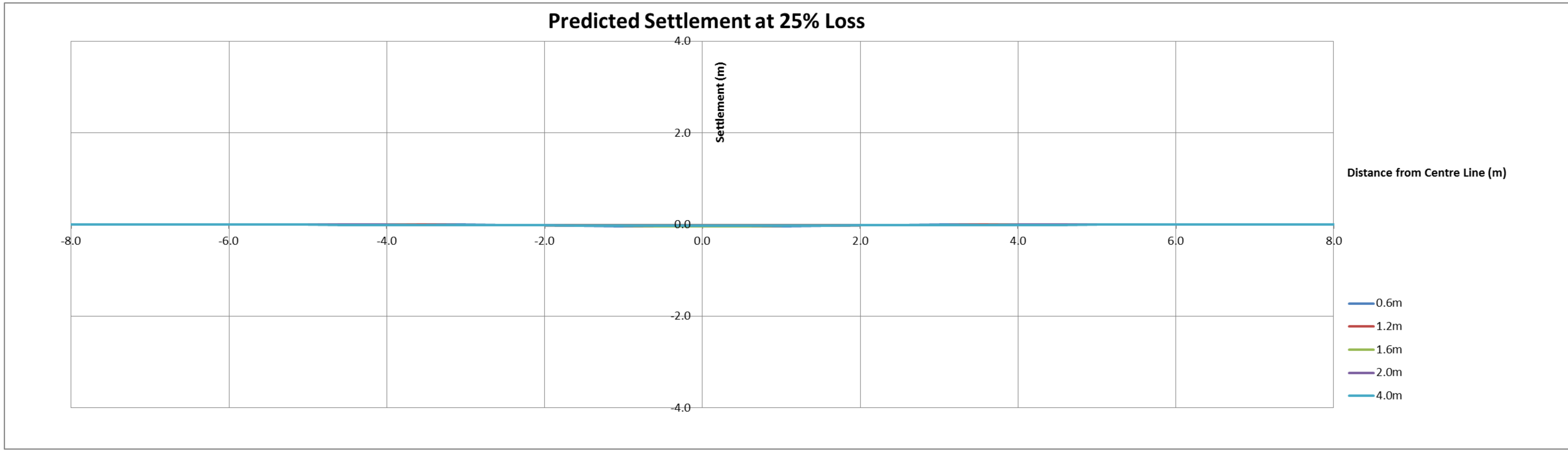


(a)

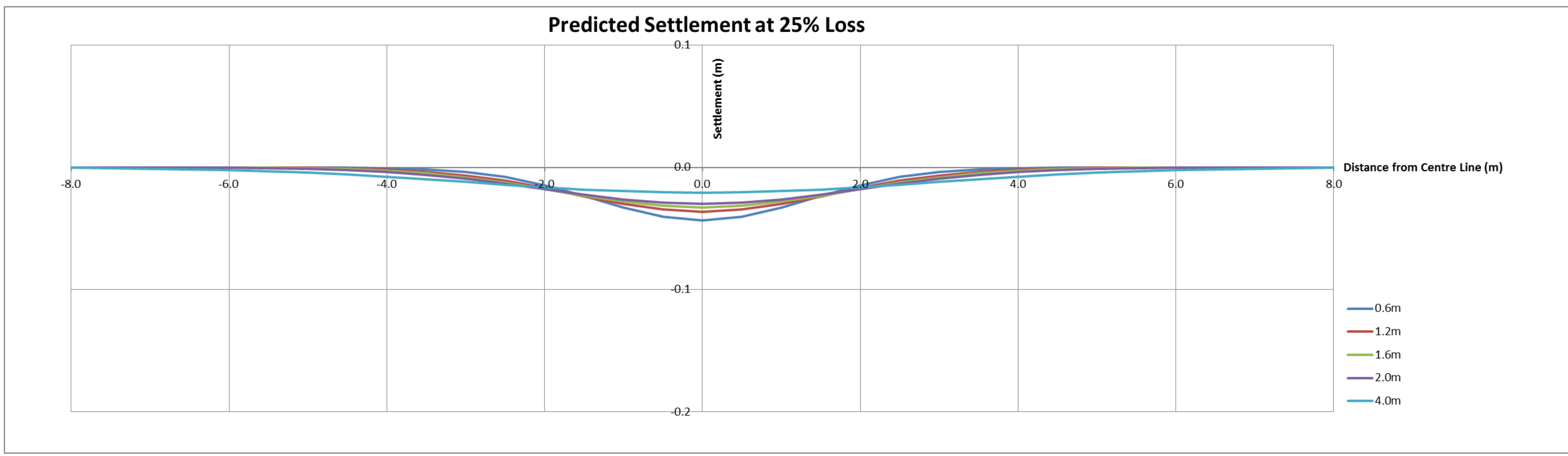


(b)

Figure 7A - 3: Predicted settlement profile at ground level for different depths of cover assuming 50% volume loss (a) equivalent horizontal and vertical scales (b) vertical scale magnified to ten times the horizontal scale



(a)



(b)

Figure 7A - 4: Predicted settlement profile at ground level for different depths of cover assuming 25% volume loss (a) equivalent horizontal and vertical scales (b) vertical scale magnified to ten times the horizontal scale

1 SECTION B – PTAC MODEL SETUP

Parameter	Symbol	Value	Comments
Max soil density	$\rho_{soil,max}$	2000 kg/m^3	The max soil density results in the lowest predicted load bearing capacity for the pipe, range indicated along pipeline from 990 kg/m^3 to 2000 kg/m^3
Yield strength of X52 pipe	$\sigma_{y,X52}$	359 MPa (52,000 psi)	
Pipe diameter	D	0.8636 m	
Young's Modulus	E	205 GPa	
Soil Modulus	E'	6.9 MPa	E' increases with increasing depth of cover and increased compaction [Hartley & Duncan]; the use of 6.9 MPa is recommended for coarse-grained soils with fines at 90% compaction and also for fine-grained soils with less than 25% sand content at 95% compaction at less than 1.5 m depth of cover, therefore this is conservative due to the compaction level assumed and especially with respect to the majority of crossings at deeper depths of cover
Bedding factor	K	0.1	Conservative for buried pipe that is in intimate contact with soils at the side wall, such as soil compacted over 60 years or constructed to CPCS-SPEC-PIPELINE-001: Specification for Pipeline Construction, 19.3.2: which states compaction to 98% of Standard Proctor Density
Lag factor	L	1.5	Values of 1.0 to 1.5 acceptable, 1.5 is most conservative and accounts for Spangler's observation that culvert ovality can increase over long periods of time, values closer to 1.3 have been suggested for pipe by Warman et al
Safety factor	FS	3	Applied to elastic collapse to account for stress concentrations due to perforations, see Section 7.4.6.3.2 for details
Impact factor	F'	1.75	Recommended for Railway by Warman et al, the impact factor also decreases with depth to a value of 1.0 at a depth of only 0.9m (3.0 ft) for traffic live loads, therefore this is conservative
Pipe diameter	D	0.864 m	
Pipe modulus of elasticity	E	2.05×10^{11} Pa	
Height of soil above pipe (DOC)	C	variable	
Modulus of soil reaction	E'	6.9 MPa	
Gravitational constant	g	9.81 m/s^2	
Yield strength of pipe	σ_{yield}	3.59×10^8Pa	
Dry density of soil	γ_S	2000 kg/m^3	
Bedding factor (for pipeline constructed by trenching)	K	0.1	
Density of water	γ_W	1000 kg/m^3	
Height of water table above pipe	h_W	0 (for pipe above water table)	
Lag factor (empirical)	L	1.5	
Effective load from traffic (from "Guidelines for the Design of Buried Steel Pipe," ASCE, July 2001)	P_{pipe}	variable (function of DOC, "C")	
Impact factor	F'	1.75 or 1.0 as stated	
Factor of safety	FS	3.0	

2

Assumptions and data inputs

Conservative assumptions were used in the model as necessary, and summarized below:

- The pipe is above the water table and there is no jacking of the pipe.
- The coating provides no significant stiffness.
- A conservative impact factor is used for all depths of cover.
- Soil behaves in the following way:
    - Soil will collapse along 45° planes as the shear stresses are highest along these planes.
    - When the pipeline collapses, soil flows efficiently and fills the empty void of the pipeline.
    - The volume of soil filling the pipeline can be calculated and used to estimate the depth of subsidence at the ground surface.
    - The prism of soil above the pipeline subsides by a depth of “S” after pipeline collapse.

SECTION C – ASCE LOADING CONDITIONS

TABLE 7A - 1: LIVE LOADS TRANSFERRED TO PIPE (KPA)

LIVE LOADS TRANSFERRED TO PIPE (kPa)				ADDENDUM	
Height of Cover (m)	**Highway H20***	**Railway E80****	**Airport*****	**Personal Truck******	**Person*******
0.3	86	–	–	21.6	5.0
0.6	38	182	91	9.6	1.3
0.9	29	163	85	7.2	0.6
1.2	19	127	78	4.8	0.3
1.5	12	115	70	3.0	0.2
1.8	10	108	61	2.4	0.1
2.1	8	84	54	2.1	0.1
2.4	5	77	48	1.2	0.1
3.0	–	53	42	–	–
3.7	–	38	33	–	–
4.3	–	29	21	–	–
4.9	–	24	16	–	–
5.5	–	19	13	–	–
6.1	–	14	11	–	–
6.7	–	13	8	–	–
7.3	–	12	7	–	–
7.9	–	10	–	–	–
8.5	–	7	–	–	–
9.1	–	5	–	–	–
10.7	–	–	–	–	–
12.2	–	–	–	–	–

* Simulates a 20-tonne truck traffic load, with impact.
** Simulates an 11 tonne / m railway load, with impact.
*** Simulates 82 tonne dual tandem gear assembly, 0.66 m spacing between tires and 1.68 m centre-to-centre spacing between fore and aft tires under a rigid pavement 30 cm inches thick, with impact.
**** Simulates a 5 tonne personal truck load, with impact
***** Assumes 100 kg person, no impact

SECTION D – HIGHWAY CLASSIFICATION

Alberta

In Alberta, "Primary Highways are divided into two series, the "1-216 Series" makes up Alberta's core highway network, has the highest traffic volume, and are mostly paved. The "500-986 Series", formerly known as the "Secondary Highways", provide more local access, and include a large number of gravel highways."[1]

Saskatchewan

Saskatchewan highways can also be divided into seven classes.

Class 1 - serve major inter-provincial and international travel as well as regional service centres with 3,000 or more. These highways also link between regional and base hospitals.

Class 2 – serves population centres of 1,000 or more and provide a link between hospitals.

Class 3 – serve communities of 500 or greater and link health centres or special care homes to hospitals.

Class 4 – considered as primary inter-municipal roads that provide access to communities of more than 100 and large industrial sites.

Class 5 - considered as secondary inter-municipal roads that provide access to communities of less than 100 and medium industrial sites.

Class 6 – serves residences, school bus routes and small industrial sites.

Class 7 – provide access to land only.[2]

Manitoba

Manitoba's highway classification system defines highways under control of MIT as

1. RTAC routes
2. Class "A1" highways – Provincial Truck Highways numbered from 1 to 110 that are not RTAC routes
3. Class "B1" highways – highways with a numeric designation above 110. Note that some B1 highways have been upgraded to RTAC or A1 loadings.[3]

---

1 http://en.wikipedia.org/wiki/List_of_Alberta_provincial_highways

2 Saskatchewan Highways and Infrastructure, "Design Manual", Government of Saskatchewan,1992

3 Manitoba Highway Classification System, Government of Manitoba website, http://www.gov.mb.ca/mit/mcd/mcpd/mhcs.html