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ENBRIDGE
NORTHERN
GATEWAY PIPELINES

Northern Gateway Pipelines Limited Partnership

Semi-Quantitative Risk Assessment

**Submitted in Response to Joint Review Panel
Information Request Number 8.1(b)**

Enbridge Northern Gateway Project

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EXECUTIVE SUMMARY

This *Semi-Quantitative Risk Assessment* (SQRA) was prepared by WorleyParsons Canada Services Ltd. (WorleyParsons) for Northern Gateway Pipelines Limited Partnership (Northern Gateway) under the Enbridge Northern Gateway Project (the Project).

The SQRA is submitted in response to the Joint Review Panel (JRP) Information Request (IR) Number 8.1(b), and in support of a risk-based design process. Risk-based design is an iterative approach that evaluates and prioritizes risks associated with a preliminary design (termed 'unmitigated risks' in this report), and their associated risk-drivers, and then establishes mitigation measures to be incorporated into the design to address the principal unmitigated risks. The SQRA provides a risk assessment of a spill from the Northern Gateway oil line for the risk associated with a full-bore rupture and release of diluted bitumen (dilbit).

The assessment methodology follows the definitions and guidelines provided in Canadian Standards Association (CSA) CSA Z662-11, Guidelines for Risk Assessment of Pipelines. The magnitude of risk as defined by this standard is the combination of the frequency or likelihood of an event and the consequence of the event if it happens.

A semi-quantitative risk assessment is a combination of probabilistic modelling along with semi-quantitative scoring methods. The risk severity is based on a risk matrix of likelihood or frequency and consequence specific to this Project.

The SQRA process steps are described in the following paragraphs.

The first step in the SQRA was to identify hazard and threat events, including: internal and external corrosion; manufacturing and construction defects; incorrect operations and equipment failure; third-party damage; and geotechnical and hydrological threats.

The next step was to determine the failure frequency based on reliability methods and expert judgement. Northern Gateway engaged Dynamic Risk Assessment Systems Inc. (Dynamic) to develop a quantitative failure frequency model. Using reliability methods addressed the primary challenge associated with deriving quantitative risk values for new pipelines. AMEC Environment & Infrastructure (AMEC), a division of AMEC Americas Limited, was engaged to provide a semi-quantitative assessment of failure frequency of geohazards building on AMEC's original work identifying geohazards for the application.



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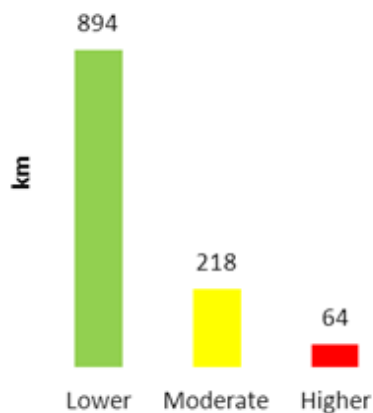
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The third step was to evaluate consequences, beginning with spill trajectory modelling to determine whether a product release will affect a consequence area. The magnitude of the effect is a function of spill volume, accessibility, and inherent sensitivity of the particular consequence area.

The final step was to evaluate unmitigated risk severity. Risk severity was evaluated through the risk matrix developed for the project as a combination of the frequency of rupture and the consequence, given a rupture.

While most of the pipeline route has a low-risk rating, the assessment confirmed a number of higher risk areas, primarily associated with high-value watercourses such as the Kitimat River. A summary of the SQRA results based on the current Route Revision U is shown in the following chart.



Overall distribution of unmitigated risk severity by one-kilometre segments

The terrain and geotechnical conditions that this pipeline traverses are similar to those of other liquid transmission pipelines in Canada and throughout the world. The products carried by this pipeline are also carried by other existing pipelines in Canada and the United States.

This SQRA was based on assessing risk from a full-bore rupture on the proposed oil pipeline. Northern Gateway recognizes that a release of any magnitude from the pipeline is unacceptable and will undertake additional work during the detailed design phase to identify and apply mitigation to minimize risk of a release.

The Project is undertaking a more detailed evaluation of higher risk sections of the Coast Mountain portion of the Route Revision U. This evaluation will focus on risk reduction for threats identified, as well as



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reducing the overall risk along the Kitimat River. It will be a demonstration of the approach that will be taken for other higher risk areas and will inform detailed engineering design in subsequent project phases.

Further work will be undertaken by Northern Gateway in detailed design, construction and operations using the liquid pipeline risk assessment and management tools being developed by Enbridge.



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1. INTRODUCTION

This *Semi-Quantitative Risk Assessment* (SQRA) was prepared by WorleyParsons Canada Services Ltd. (WorleyParsons) for Northern Gateway Pipelines Limited Partnership. (Northern Gateway) under the Enbridge Northern Gateway Pipeline (the Project).

Northern Gateway recognizes and shares the public's concern about the consequences of oil spills. The pipeline industry is very much aligned with its regulators and the public in wanting to avoid spills of any size.

Northern Gateway's objective of pipeline design, engineering, construction and operations is to mitigate and manage the level of risk over the life of the pipeline with the goal of avoiding spills of any size. Risk-based design is especially critical for those areas identified as higher risk. This report will serve as part of the basis for subsequent design decisions.

Enbridge is the operator of the longest liquids pipeline system in the world. As part of Enbridge's commitment to continuous improvement, a suite of risk assessment tools are under development for use in operational settings. This includes development of a quantitative risk assessment model and risk assessment matrix applicable to mainline operations. When completed, these will assist Enbridge Operations in evaluating and prioritizing operational safety initiatives and programs, and will provide an important supplement to ongoing pipeline integrity management programs. These risk management tools and innovations will be available to Northern Gateway as it proceeds into detailed design, construction, and operations.

1.1 Purpose of the Semi-Quantitative Risk Assessment

This SQRA report is supported by the Quantitative Failure Likelihood Assessment report contained in Attachment 2, and the Report on Quantitative Geohazard Assessment contained in Attachment 4. These reports were prepared in keeping with Northern Gateway's commitment to a risk-based design. The risk-based design process is an iterative approach that evaluates and prioritizes risks, and their associated risk-drivers, and then establishes mitigation measures to be incorporated into the design to address the principal risks. Because risk-based design is a process that focuses on identifying and pre-empting risk, it is a more rigorous approach than more traditional design approaches that don't incorporate specific risk assessment to identify and pre-empt risks.

Consistent with the guidance that was given during the JRP IR process to characterize full-bore rupture effects, (March 2011), the SQRA report focuses exclusively on ruptures. Nevertheless, because Attachment 2 evaluates and characterizes all failure modes (leaks and ruptures), guidance from that reference document will be used in the risk-based design process for mitigating failure likelihood. From the



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perspective of consequence mitigation, the focus of the SQRA is on ruptures because ruptures have the most extreme consequence and are of the greatest interest in completing risk-based design. This is because any consequence mitigation measures that are developed and incorporated into the design for mitigating ruptures will also be effective in mitigating less significant releases.

This document describes

- the components and methodology of the risk assessment, including the threat evaluation, the frequency assessment and the risk evaluation;
- the results of the risk assessment; and
- a discussion of these results and next steps.



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1.2 Background

1.2.1 Project description

Northern Gateway, a subsidiary of Enbridge Pipelines Inc., has initiated the regulatory phase of the Project to obtain the required approvals. The Project is being developed to provide pipelines and associated facilities to transport approximately 83,400 m³/d (525,000 bbl/d) of oil from Bruderheim, Alberta, to Kitimat, British Columbia (B.C.), and approximately 30,700 m³/d (193,000 bbl/d) of condensate from Kitimat to Bruderheim. It includes the following major components:

- an oil pipeline, 914 mm OD (NPS 36) approximately 1,176-km long, extending from the outlet of the Bruderheim Station to the Kitimat Terminal
- a condensate pipeline, 508 mm OD (NPS 20) approximately 1,176-km long, located in the same right-of-way (ROW) as the oil pipeline and extending from Kitimat Terminal to the Bruderheim Station
- the Bruderheim Station, consisting of the oil initiating pump station and condensate receiving facilities
- eight intermediate pump stations located at intervals along the pipelines
- a 6.5-km-long tunnel and a 6.6-km-long tunnel to route the oil and condensate pipelines through the Clore River and Hoult Creek valleys
- Kitimat Terminal, which will comprise the following:
 - a tank terminal including oil tanks, condensate tanks and associated infrastructure
 - a marine terminal including two tanker berths and one utility berth
 - an initiating condensate pump station
 - oil receiving facilities



1.3 Terminology

Table 1 provides definitions for terminology used in this report. Appendix A lists abbreviations used in this document.

Table 1: Terms and definitions used in this report

Term	Definition
Consequence	The effect of a hydrocarbon spill on individuals or populations, property, or the environment
Consequence area	Term provided by the Joint Review Panel in their request for additional information as “onshore and/or offshore including but not limited to: wildlife reserves, occupied areas, Indian Reserves, urban areas or towns, water bodies, federal or provincial campgrounds and parks and town water intake locations”. This term has been subsequently replaced by “high consequence area” in Northern Gateway’s assessment.
Frequency	The likelihood of an event, expressed qualitatively or quantitatively (such as failures per km-year).
Geohazard	A threat from a naturally-occurring geological process or condition that may lead to damage. The process may be triggered by natural or anthropogenic causes. For the purposes of this assessment, the damage is damage to the pipeline that might lead to a rupture. Examples include mass wasting, deep seated slides, debris flows, rock fall, avalanches and hydrological events. Also referred to as geotechnical hazard.
High consequence area (HCA)	Equivalent to and supersedes the term “consequence area” for Northern Gateway’s assessment.
Project effects assessment area (PEAA)	The maximum area where project-specific environmental effects can be predicted or measured with a reasonable degree of accuracy and confidence.
Risk	A compound measure of the frequency and severity (consequences) of an adverse effect.
Risk assessment	The process of risk analysis and risk evaluation.
Risk-based design	An iterative design process that evaluates and prioritizes risks and the affiliated risk-drivers that are associated with a preliminary design, and then establishes mitigation measures to be incorporated into the final design to address the identified principal risks.
Rupture (full-bore rupture)	A type of failure of the oil pipeline which allows the product to be released in an unconstrained manner into the surrounding environment.
Spill trajectory modeling	A numerical modeling technique that estimates the extent of a spill based on modeled release outputs, topographical and hydrodynamic parameters.
Unmitigated risk	The term ‘unmitigated risk’ is used in this document in the context of the risk-based design process, whereby it refers to the risk associated with a preliminary design, and prior to the implementation of mitigation measures that are identified and guided by the risk assessment.



2. OVERVIEW

2.1 Semi-Quantitative Risk Assessment

As defined in FAO (2009), semi-quantitative risk assessment provides an intermediary level between the textual evaluation of qualitative risk assessment and the numerical evaluation of quantitative risk assessment, by evaluating risks using a scoring approach, as shown in Figure 1. It offers a more consistent and rigorous approach to assessing and comparing risks and risk management strategies than does qualitative risk assessment, and avoids some of the greater ambiguities that a qualitative risk assessment may produce.

As employed in this analysis, semi-quantitative risk assessment incorporates a quantitative evaluation of failure frequency and a semi-quantitative evaluation of consequence. The characterization of risk in this semi-quantitative risk assessment is sensitive to design parameters, and so it is a useful tool for providing guidance in a risk-based design process, whereby the potential for risk reduction through alteration of those design parameters can be investigated.

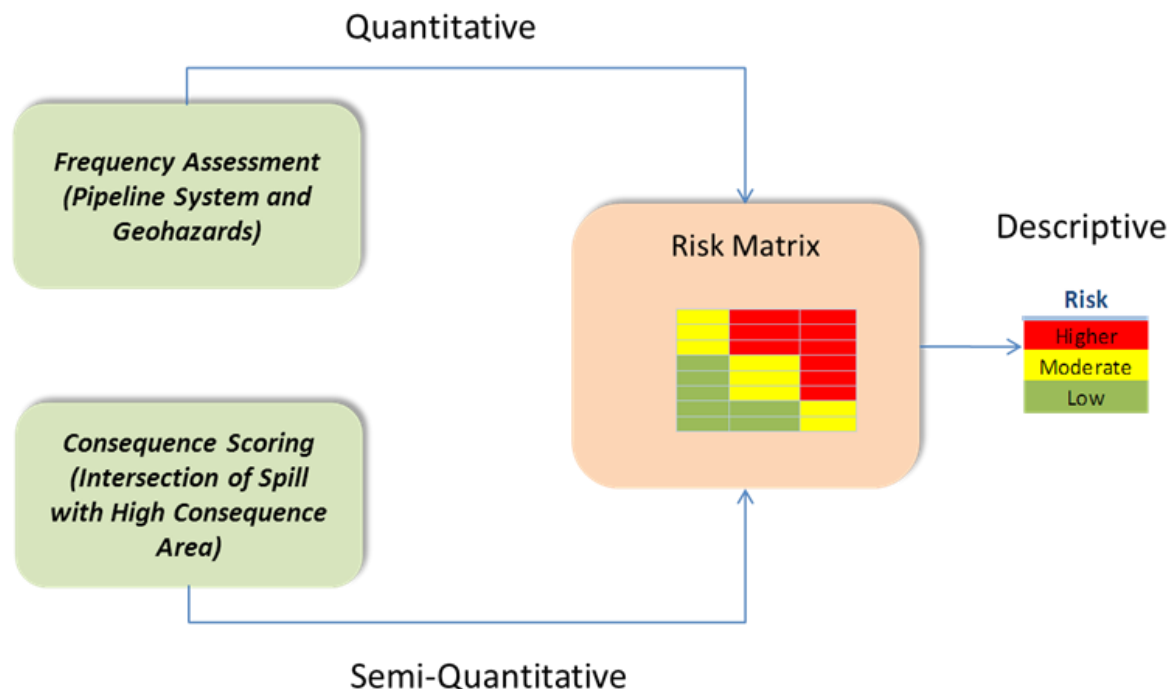


Figure 1: Components of the semi-quantitative risk assessment

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2.2 Northern Gateway Oil-Spill Risk Assessment Timeline

Information on the environmental effects of spills and the management of spills (including ruptures) for the pipelines was provided in Volume 7B of the Project's National Energy Board (NEB) Section 52 Application (Northern Gateway 2010).

Following a review of the Application, the JRP in its Panel Session Results and Decision dated 19 January 2011, determined that additional information on the pipelines' design and risk assessment was required prior to issuing a hearing order for the Project. A specific request was to provide:

Geographically referenced maps at a 1:25,000 scale (such as GIS) describing the geographical extent, on land and water, from potential hydrocarbon releases on consequence areas. The potential hydrocarbon release volumes shall be determined based on full-bore ruptures within each kilometre post distance.

In the March 2011 response to the JRP (Northern Gateway 2011), the Project provided pipeline maps showing the extent of releases based on a full-bore rupture scenario for the oil pipeline and the consequence areas. The Project also provided pipeline plots showing elevations and potential volumes from releases.

The risk assessment presented in this report builds on the work completed in March 2011 by developing a process to assess the frequency, consequences, and risk of a full-bore rupture scenario on what the Project now refers to as high consequence areas (HCAs). The assessment results reported are intended to be used as a screening-level tool to inform ongoing risk-based design and engineering.

2.3 Assessment Methodology Overview

The assessment methodology follows the definitions and guidelines provided in CSA Z662-11, Annex B (CSA 2011). The magnitude of risk, as defined by this standard, is the combination of the frequency or probability of an event and the consequence of the event if it happens. The methodology, shown in Figure 2, was described in detail in a previous filing: *Framework for Semi-Quantitative Risk Evaluation*, response to JRP IR 8.1, 21 November 2011.



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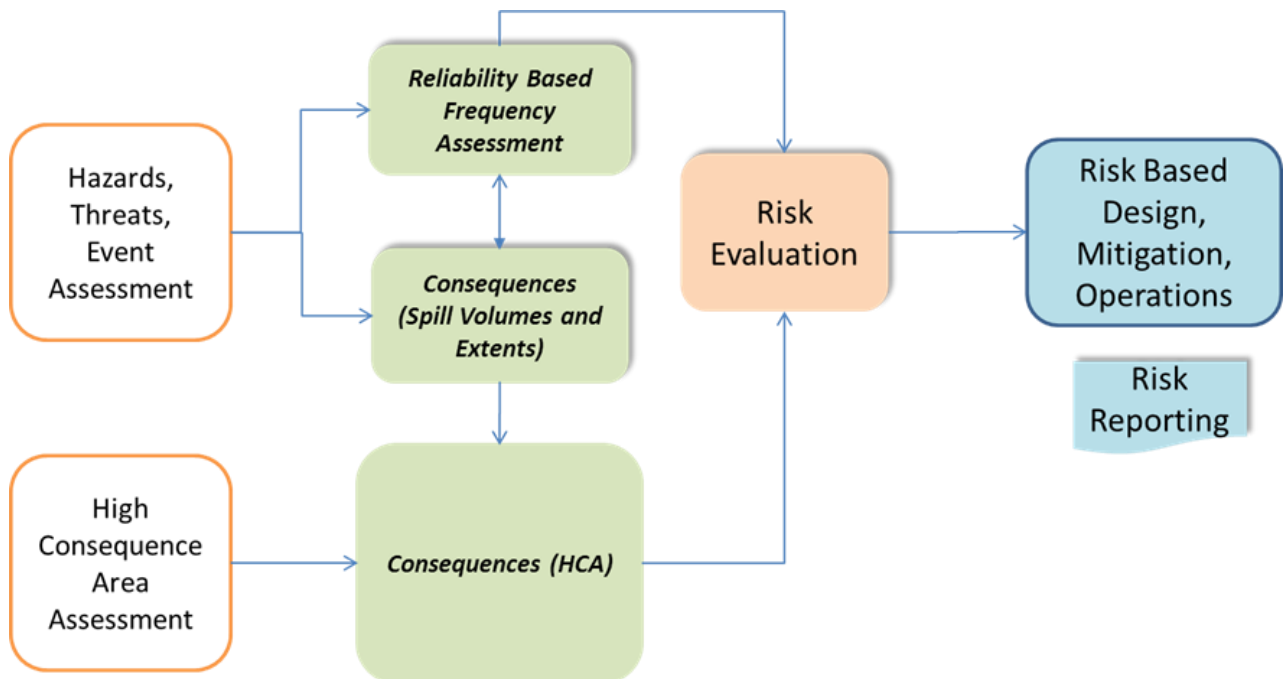


Figure 2: Overview of methodology

WorleyParsons engaged Dynamic on behalf of the Northern Gateway to develop a quantitative failure frequency model for threats (except for the geohazards discussed below) associated with the construction and operation of the pipeline system. Historical pipeline industry failure statistics are not representative of modern pipeline designs, materials and operating practices. The threat-based approach developed by Dynamic uses actual operating data from recently constructed (modern) pipelines with similar technology and products in conjunction with reliability-based methods (where relevant to the threat being considered) to predict potential failure mechanisms.

AMEC was engaged to provide a quantitative assessment of failure frequency of geohazards building on AMEC's original work identifying geohazards for the application.



3. HAZARDS, THREATS AND EVENT IDENTIFICATION

3.1 Pipeline System Threats

As a starting point to the risk assessment, Dynamic conducted a Threat Assessment Workshop at the Enbridge offices in Edmonton, Alberta, see Attachment 1. Enbridge operations, maintenance and pipeline integrity representatives participated in the workshop.

The objective of the threat assessment workshop was to identify and discuss potential threats to a pipeline system considering materials, design, construction and operational variables. Through this review, the relevance and severity of each threat was assessed in the context of the proposed Northern Gateway Pipeline.

Relevant threats to the Northern Gateway Pipeline were identified as follows:

- external corrosion
- internal corrosion
- materials and manufacturing effects
- construction (welding, fabrication and installation) defects
- third-party damage
- incorrect operations
- equipment failures (such as at pump stations)

3.2 Geotechnical Hazards and Threats

Geotechnical threats along the pipeline were identified and presented in Application Volume 3, Appendix E-1 - Overall Geotechnical Report on the Pipeline Route Revision R for the Enbridge Northern Gateway Project, March 2010. Appendix B, Table B-1 of the application provided a comprehensive description of the geohazards identified.

Much of geotechnical work supporting the application was used to eliminate many significant hazards through routing choices. The present geohazard evaluation now only considers residual hazards associated with the current Route Revision U.



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In the response to the JRP request for additional information (March 2011), Northern Gateway provided additional discussion of the threats associated with the areas of high geotechnical risk and for routing through the Rocky and Coast Mountains with areas of mass wasting. In the response, examples were provided to illustrate in more detail the process used, geotechnical issues and mitigation to be employed.

The geohazard evaluation considered threats within the project effects assessment area (PEAA), as well as hazards outside this corridor that could potentially affect the pipeline. For example, rock fall, avalanches, debris flows and various forms of slides were assessed to distances of sometimes several kilometres from the Route Revision U and were typically assessed to the height of land above the corridor. Approximately 250 km of the route (20%) has associated geotechnical threats.

Descriptions of the threat assessments and the threat evaluation methodology are presented in Attachment 4.



4. FULL-BORE RUPTURE FAILURE FREQUENCY ASSESSMENTS

A summary of the methodology and results of full-bore rupture failure frequency assessments is provided in this section.

4.1 Pipeline System Failure Frequency

The following sections summarize the methods employed and reports on the results of the failure frequency assessments undertaken by Dynamic. Details of the methodology and selection process for analog data are found in Attachment 2.

4.1.1 External corrosion

4.1.1.1 Summary of methods

The reliability approach for external corrosion employs the superimposition of an analog in-line inspection (ILI) dataset upon the design and materials for the Northern Gateway oil pipeline, factoring in tool measurement error and corrosion growth rates. The reliability analysis models how pipeline materials and design responds to an anticipated degradation process.

After a review of candidate ILI datasets, the external wall loss feature list from the 2010 ILI of Enbridge's Line 4 (Bethune Station–Regina Terminal) was selected as the appropriate analog dataset. Several factors were considered in selecting that inspection dataset to ensure that it could be established as being representative of corrosion performance anticipated for the Northern Gateway pipelines. The standards for coating types, coating specifications and cathodic protection are the same as those anticipated for Northern Gateway.

The methodology employs a probabilistic simulation approach where the growth of corrosion features can be simulated over time. From a baseline of zero, the model will predict how failure likelihood increases to finite levels and beyond, and how design parameters will affect the change of unmitigated failure likelihood with time.

4.1.1.2 Results

Absent any integrity management program, the models run for external corrosion did not show any measurable probabilities of corrosion failure until after 11 years of simulated unmitigated operation.



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However, Northern Gateway's integrity management monitoring and mitigation procedures will be implemented at start-up to maintain a negligible probability of failure over the entire operating life.

4.1.2 Internal corrosion

4.1.2.1 Summary of methods

As in the approach for external corrosion, an analog ILI dataset was chosen and superimposed on the preliminary Northern Gateway design and materials, factoring in tool measurement error and corrosion growth. To ensure that the internal corrosion mechanism and corrosivity that is represented by the analog ILI dataset are representative of those that would be expected in the Northern Gateway pipelines, the following factors were examined: water content, erosion and corrosion, flow velocity, flow mode, temperature, susceptibility to under-deposit corrosion (such as solid deposition, microbiologically-induced corrosion, potential, and water chemistry), and mitigation measures (use of inhibition, biocides, or pigging).

Through this process, it was determined that the ILI data obtained from Enbridge's NPS 36 Line 4 would be most representative of the corrosivity conditions expected on the Northern Gateway crude oil pipeline.

Approximately 10,000 km-years' (distance of pipeline inspected times the number of years of operation) worth of ILI data from the NPS 36 Line 4 was reviewed.

4.1.2.2 Results

No evidence of active internal corrosion was found.

The pipeline will operate in fully-turbulent mode, resulting in full entrainment of what little water is present (the maximum basic sediment and water tariff specification for the Northern Gateway crude oil pipeline is 0.5%). Therefore, as a result of these operating conditions, no significant internal corrosion is expected on this pipeline and the failure probability for this threat is negligible.

4.1.3 Materials and manufacturing defects

4.1.3.1 Summary of methods

Materials defects failures are failures that are a direct result of the presence of pipe body or seam weld defects. The threat of materials and manufacturing defects does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Therefore, the approach that was used to estimate the frequency of



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occurrence for this threat employs a baseline failure frequency derived from industry failure statistics, modified by an adjustment factor to account for modern pipeline materials, design, and installation practices.

Failure statistics by cause for hazardous liquid pipelines were published by Restrepo et al. (2009). This report describes failure incidents for various causes and sub-causes occurring over the 170,000-mile hazardous liquid pipeline infrastructure in the U.S. from the period January 2002 to December 2005.

PHMSA data were used since they are based on a large database of pipeline failures, including both leaks and ruptures, which are derived from significant pipeline infrastructure. As such, these failure incident data have a large degree of statistical relevancy. Furthermore, the PHMSA incident failure database contains information associated with each incident that affords the ability to ensure the relevancy of the data to the pipeline being modeled and enables conclusions to be drawn relative to issues such as the magnitude of release for associated threats, and the underlying causes of failure.

4.1.3.2 Results

In Restrepo et al. (2009), 19 failures were attributed to materials defects. This equates to a failure frequency of 1.7×10^{-5} failures/km-year.

The most modern pipelines considered in Restrepo et al. were constructed in the 1980s and 1990s, and had a normalized incident rate that was 15% of the pipeline infrastructure as a whole. To account for this effect, a modern construction adjustment factor of 0.15 was employed in the calculation of materials defects failure frequency. This results in a failure likelihood of 2.6×10^{-6} failures/km-year.

To establish release outcomes associated with materials defects, the PHMSA leak database (2002 to 2009) was queried for onshore, large-diameter pipelines. Two failure incidents were found; one a leak, and the other a full-bore rupture. Therefore, based on this industry experience, an assumption was made that 50% of all materials defects failures result in full-bore ruptures, and the other 50% result in leaks.

Under this assumption, the resultant failure likelihood for a full-bore rupture would be 3×10^{-6} failures/km-year.



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4.1.4 Construction – (welding and installation) defects

4.1.4.1 Summary of methods

Construction defect failures are failures that are attributed to construction or installation defects, such as girth weld defects. The threat of construction defects does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Therefore, the approach that was used to estimate the frequency of occurrence for this threat employs a baseline failure frequency derived from industry failure statistics, modified by an adjustment factor to account for modern pipeline materials, design, and installation practices.

In Restrepo et al. (2009), failure incidents for various causes and sub-causes occurring over the 170,000-mile hazardous liquid pipeline infrastructure in the U.S. over the period January 2002 to December 2005 are reported. Data from this study was used to derive baseline failure rates for construction-related defects and equipment failure.

4.1.4.2 Results

In the four-year period examined, three sub-causes were related to the major threat category of construction defects failure. These construction defects failure sub-causes were as follows:

- body of pipe failures, such as dents (16)
- butt weld failures (15)
- fillet weld failures (9)

Combined, these 40 failures represent a failure frequency of 3.7×10^{-5} failures/km-year. This value was employed as the baseline failure frequency for construction defects.

A review of the construction defects failure statistics determined that the normalized rate of materials defects incidents varied by decade of construction.

The most modern pipelines that were considered in the study (constructed in the 1980s and 1990s) had a normalized incident rate that was 60% of the pipeline infrastructure as a whole. To account for this effect, a modern construction adjustment factor of 0.60 was employed in the calculation of construction defects failure frequency, resulting in a failure likelihood of 2.2×10^{-5} failures/km-year.

Absent some large-scale outside force, failures due to construction defects such as girth weld defects, which are oriented in the plane of the principal pressure-containing stresses, fail by a leak mechanism,



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rather than by a rupture, and the probability for a full-bore rupture is negligible. This is consistent with the findings of a review of failure incidents from the PHMSA leak database related to construction defects.

4.1.5 Third-party damage

4.1.5.1 Summary of methods

The potential for strikes and damage to any size pipeline increases with human activity such as excavation, oil and gas activity, and road works. Proximity to urban areas and settlements or to commercial operations creates a potential for third-party damage.

There is evidence that, even with proximity to urban or commercial areas, the threat is limited to pipeline strikes from larger machines. Chen and Nessim (1999) demonstrated that machines smaller than excavators do not significantly affect predicted failure probability.

The probability that there may be an excavator strike is dependent on both site-specific and operational factors that are combined using a fault tree approach outlined by Chen and Nessim (1999). Factors considered include the following:

- land use (defines overall frequency of excavation on pipeline ROW)
- placement frequency of pipeline marker signs
- use of buried marker tape at crossings
- third-party requirements regarding notification of intent to excavate
- pipeline patrol frequency
- depth of cover

Land use is a key factor in the third-party damage model that influences the probability of impact by an excavator.

The dominant land use is active or inactive logging operations as well as active oil and gas sites. Only 87 km (7% of the route) through the Rocky Mountains and the Coast Ranges was classified as “very remote” without any commercial or recreational land use evident. Low density residential is associated with Burns Lake while the Industrial designation is associated with the route extent near Kitimat and the terminal.

Figure 3 illustrates the distribution of land use types along the route.



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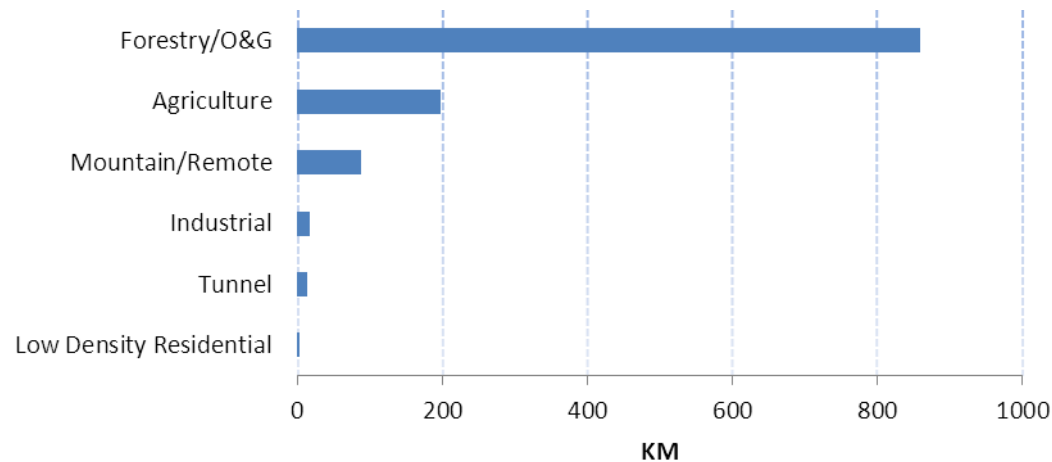


Figure 3: Land use distribution

4.1.5.2 Results

A fault tree hit-frequency model in conjunction with a probabilistic damage resistance algorithm was used to calculate the frequency of failure for defined segments along the pipeline route. This frequency was then adjusted for the percentage of incidents that would result in a full-bore rupture. The percentage for full-bore rupture from third-party damage failures are 25%, based on the mechanical damage incidents reported by Chen and Nessim (1999).

Figure 4 shows the assessed frequency for third-party impacts resulting in a full-bore rupture plotted along the route.



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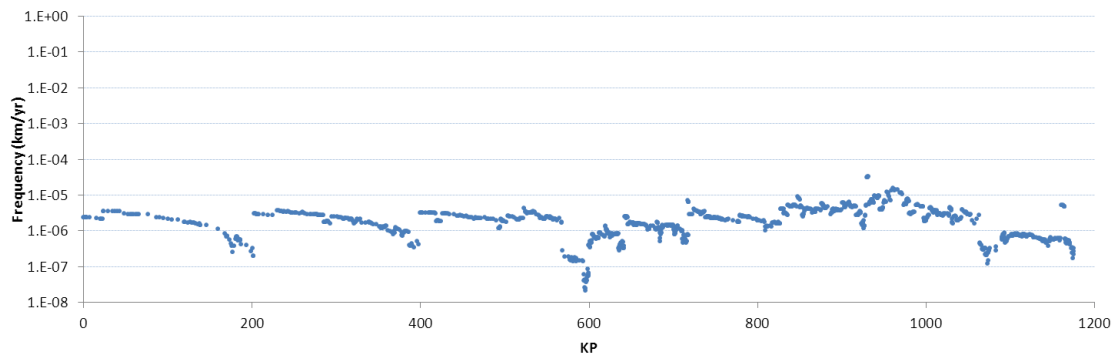


Figure 4: Frequency of third-party damage creating a full-bore rupture

4.1.6 Incorrect operations

4.1.6.1 Summary of methods

Incorrect operations failures are related to a failure to follow set procedures during the operation of a pipeline. The threat of incorrect operations does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Therefore, the approach that was used to estimate the frequency of occurrence for this threat employs a baseline failure frequency derived from industry failure statistics, modified by an adjustment factor to account for modern pipeline materials, design, and installation practices.

Estimates of failure frequency were based on operating incident data related to this threat, modified by an adjustment factor. The adjustment factor was derived from a questionnaire developed by Dynamic and administered to Enbridge Operations and other subject matter experts during the threat assessment workshop. The questionnaire is based on the *Pipeline Risk Manual: Ideas, Techniques, and Resources, Third Edition*, by W.K. Muhlbauer, and incorporates elements from American Petroleum Institute (API) RP 581 *Risk Based Inspection Technology*. It covered topics that were intended to gauge the performance of Northern Gateway operations in terms of the causal factors of failure related to incorrect operations. The methodology for assigning the adjustment factor based on the questionnaire results was derived from API RP 581.

4.1.6.2 Results

Restrepo et al (1999) attributes 61 failures to incorrect operations over the 170,000-mile hazardous liquid pipeline infrastructure in the U.S. over the period January 2002 to December 2005. This equates to a failure frequency of 5.607×10^{-5} failures/km-year.



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The final adjusted failure frequency was determined to be 1.828×10^{-5} failures/km-year.

To establish release outcomes associated with incorrect operations, the PHMSA leak database (2002 to 2009) was sorted for onshore, large-diameter (\geq NPS 20) pipelines transporting hazardous liquids, and 10 failures related to incorrect operations were found none of which created a full-bore rupture. Therefore, the probability of incurring full-bore failures related to incorrect operations is considered negligible.

4.1.7 Equipment failure

4.1.7.1 Summary of methods

Equipment failure encompasses the failure of non-pipe components and equipment, such as pumps, seals, valves and flanges. Except for block valves and other equipment along the ROW, failures associated with this threat occur at stations. The threat of equipment failure does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Therefore, the approach that was used to estimate the frequency of occurrence for this threat employs a baseline failure frequency derived from industry failure statistics, modified by an adjustment factor to account for modern pipeline materials, design, and installation practices.

4.1.7.2 Results

Restrepo et al. (1999) identified failure incident data for four sub-causes related to the major threat category of equipment failure as follows:

- ruptured or leaking seal or pump packing (64 failures)
- component failure (45 failures)
- malfunction of control or relief equipment (45 failures)
- stripped threads (30 failures)

Combined, these 184 failures over the four-year period over which data were collected represent a failure frequency of 1.7×10^{-4} failures/km-year. In the PHMSA database, there are no full-bore ruptures associated with this threat.

Therefore, the probability of incurring full-bore failures related to this threat is considered negligible.



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4.2 Geohazards and Hydrological Threats

The following sections summarize the methods employed and reports on the results of the failure frequency assessments undertaken by AMEC. Details of the methodology and a table of results are found in Attachment 4.

The AMEC assessment was undertaken with respect to geohazard events that would have the potential to initiate a full-bore rupture event in the pipeline. A key distinction is made between events that may occur that could affect terrain in a hazard impact area versus events that may occur that could damage the pipeline itself to the point that full-bore rupture could occur.

4.2.1 Summary of methods

The approach follows the general outline of the hazard assessment methods presented by Rizkalla, Read and O'Neil in Chapter 6 of Rizkalla (2008).

The method employed uses four key index values, or factors, to provide a numerical expression that determines the susceptibility of the pipeline to particular geohazards at discrete locations.

These factors are described in the following sections.

4.2.1.1 Occurrence factor (potential for hazard)

The occurrence factor expresses the potential for a particular geohazard to occur in a specific hazard impact zone. The factor is expressed as a value from 0 to 1, with 0 being defined as "not possible", and 1 being "defined or documented occurrence".

4.2.1.2 Frequency factor

The frequency factor used in this assessment represents the inverse of the return period for the occurrence of a particular geohazard, expressed as events per year. In general, the return period considered provides an estimated frequency for all occurrences of a specific hazard at the given location, including damaging and non-damaging events.



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4.2.1.3 Vulnerability factor

Vulnerability factor estimates the ability of the pipeline to withstand the imposed effects of a geohazard event. The factor ranges from 0 (no damage in the event of the hazard occurrence) to 1 (full-bore rupture in all geohazard occurrence situations).

For the purposes of this assessment, vulnerability is the fraction of geohazard occurrences at a specific location that would lead to a damaging event, and specifically, the fraction that would result in a full-bore rupture.

4.2.1.4 Mitigation factor

Geohazard mitigation will reduce either the vulnerability of the pipeline (such as deeper burial) or frequency of occurrence (such as slope stabilization). Mitigation measures will be implemented where elevated hazard levels are identified.

In this evaluation, the mitigation factor is an expression of the effects of implementing mitigation strategies that either increase the resistance of the pipeline to potential damage by a particular geohazard, or reduce the frequency of occurrence of a particular geohazard. Potential mitigation options are identified in each of the detailed geohazard process descriptions referenced later in this report.

Standard mitigation methods were identified for each identified geohazard occurrence. Further review, adjustment and implementation of mitigation options is expected throughout the design, construction and operation of the pipelines as part of the ongoing hazard and risk assessment process that will occur throughout the life of the pipelines.



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4.2.1.5 Results

Due to the nature of the underlying uncertainty, assessments were made on an order-of-magnitude basis. Each geohazard was assessed as having a specific failure factor and the results are reported as a frequency per threat independent of length of pipe affected. Particularly in the mountain areas, there may be more than one geohazard that affects a particular segment.

Most of the geohazards are concentrated in the Rocky Mountains and Coast Mountains but there are also geohazards such as the crossing of the Smoky River in Alberta. Along the route, most of the identified geohazards fall below 10^{-7} with current proposed levels of mitigation (unmitigated risk).



4.3 Summary of Results for Full-Bore Rupture Failure Frequencies

Table 2: Threats with full-bore rupture failure frequencies that do not vary along the route

Threat or Hazard	Assessed Value (per km-year)	Comments
External corrosion	Negligible	Failure not predicted for the time period evaluated (for example, no failures are predicted to occur between regular in-line assessments).
Internal corrosion	Negligible	No evidence of internal corrosion in analogue data or supporting evidence.
Materials and manufacturing defects	1.3×10^{-6}	Significant improvement in performance with modern manufacturing processes.
Construction defects	Negligible	Associated primarily with welding defects or improper handling and installation, leading to dents. Databases employed in this assessment do not identify full-bore rupture potential associated with this threat.
Incorrect operations	Negligible	Databases employed in this assessment do not identify full-bore rupture potential associated with this threat.
Equipment failure	Negligible	Databases employed in this assessment do not identify full-bore rupture potential associated with this threat.

Table 3: Threats with frequencies that vary along the route for a full-bore rupture

Threat or Hazard	Median Value	Highest Value	Lowest Value	Comments
Third-party damage	2.2×10^{-7} per km year	2.1×10^{-5} per km year	Negligible	Most areas of the pipeline are remote with low potential for third-party impacts.
Geohazards (includes hydrological)	1×10^{-7}	1×10^{-4}	1×10^{-11}	Highest potential for geohazards are found in the Rocky Mountains and Coast Ranges.



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4.3.1 Combined unmitigated full-bore rupture frequencies

To combine the full-bore rupture failure frequency along the pipeline route, unmitigated failure frequencies for individual threats are combined probabilistically. The result is a profile of unmitigated failure frequency along the route that is illustrated in Figure 5.

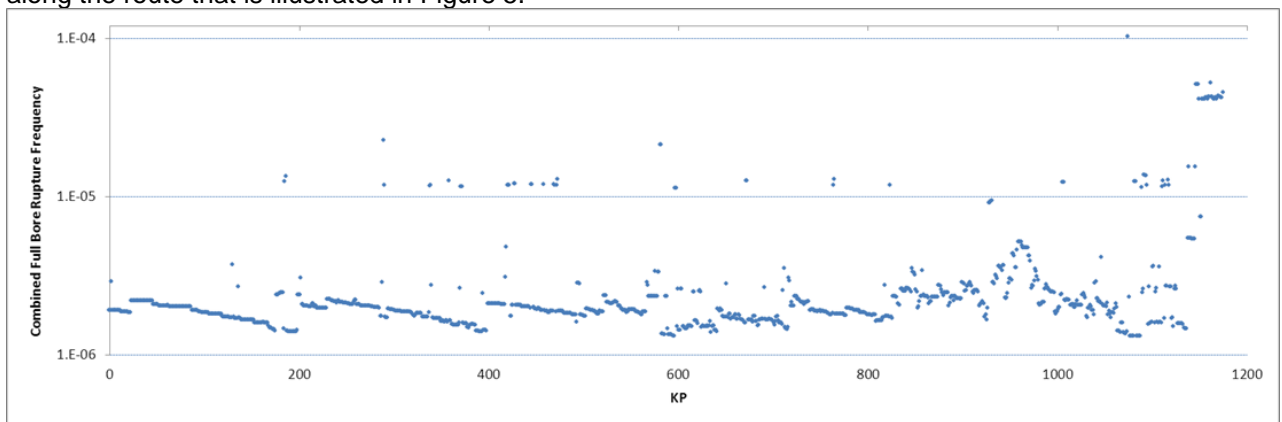


Figure 5: Full-bore rupture unmitigated failure frequency along Route Revision U

The underlying dominant pattern is the frequency of full-bore rupture from a third-party damage event. This is punctuated by geohazards in localized areas, such as river crossings along the route and, in particular, for the Coast Mountain section.

A calculation was undertaken using 1,176 segments for the total length of the pipeline, each with an unmitigated frequency of full-bore rupture. This calculation which applies a probabilistic cumulation of events attributed to all threats has identified a return period of a full-bore rupture of 240 years.



5. ASSESSING CONSEQUENCES

5.1 Full-Bore Rupture Volumes and Spill Extents

5.1.1 Calculations

The potential maximum release for a full-bore rupture is calculated using the throughput volume, pipeline elevation profile, and locations of block valves to provide an estimated volume of a spill release at any point along the pipeline. The model assumes that

- a full-bore rupture event occurs;
- the maximum throughput is 92,700 m³/d (583,000 bbl/d);
- a 10-minute spill detection time followed by a 3-minute valve activation time; and
- oil continues to be released based on static (gravity) drawdown on either side of the rupture location.

5.1.2 Full-bore rupture spill extents

In response to the JRP's request for additional information (Northern Gateway 2011; Internet site), spill modelling was conducted by Applied Science Associates using their proprietary OILMAP Land model. Attachment 3 outlines the methodology and assumptions associated with this software. The spill extent model for the full-bore rupture scenario uses the following assumptions and inputs as set out in the previous filing:

- a maximum volume release of hydrocarbons from the spill volume model.
- release of entire volume to surface.
- watercourse discharges based on a maximum mean monthly discharge*

Approximately 80% of these full-bore spills, if allowed to spread and move freely without any mitigation for 12 hours, are conservatively assumed to enter directly or indirectly into a watercourse or other body of water. Once the spill has entered a watercourse, the distance travelled is proportional to the watercourse speed.

*Note: The mean discharge for each month is averaged over a number of years. This results in 12 values. The model then uses the maximum of this dataset.



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Table 4: Full-bore rupture extent without mitigation or emergency response

Spill Extent Feature	Number	% of Total
Land-based only (does not touch water)	196	16.8
Land-based that travels outside of the 1-km corridor (500 m each side of the pipeline)	91	7.8
Water-transported	971	83.2
Water-transported that travels outside of the 1-km (500 m each side of the pipeline)	958	82.1
Water-transported that travels outside of a 10-km corridor (5 km each side of the pipeline)	612	52.4
Total spill extents modelled	1,167	
Note: 1 Water-transported includes all spills that start on land before entering water or that enter directly into a watercourse or waterbody.		



5.2 High Consequence Areas

5.2.1 Definitions

In response to the JRP request of 19 January 2011, consequence areas were identified within the PEAA, the 1-km-wide zone established for much of the Project's environmental and socio-economic assessment. Other consequence areas were defined outside the PEAA (such as parks, urban areas, watercourses and water intakes) as part of the spill trajectory modelling that defined a theoretical maximum spill extent. Maps showing the consequence areas identified by Northern Gateway were included in the Response (JRP 2011).

Northern Gateway has adopted the term HCA to align with Enbridge nomenclature. Consequence areas previously defined will now be referred to as HCAs.

HCAs include the following:

- officially designated protected areas that include federal and provincial parks, conservancies, and ecological and wildlife reserves
- settlements that include hamlets, villages, towns and cities
- Indian reserves
- licenced water withdrawal locations related to human consumption or other uses such as for industry and agriculture
- watercourses with endangered or harvested fish species
- wildlife habitat, contains species likely to interact strongly with oil and is likely to contain species at risk
- wetlands, fens and marshes

Definitions for HCAs are included in Appendix B.

5.2.2 Consequence scoring factors

5.2.2.1 High consequence area sensitivity ranking

HCAs are ranked based on sensitivity to an oil spill event. For example, watercourses with species at risk are ranked higher than other HCAs. Similarly, although many fish-bearing watercourses are identified as



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HCAs, those that contain species at risk or have a conservation concern are ranked higher than other watercourses. Details of HCA rankings and factors along with the algorithm used to calculate the consequence score are found in Appendix C.

5.2.2.2 Volume factor

As discussed earlier, spill volumes were calculated for each kilometre of the route and vary based on a number of factors such as topography and valve placement. Spill volumes were ranked and this ranking was used to modify the consequence score.

5.2.2.3 Accessibility factor

Ease of access, either by highway or paved road close to the ROW, decreases the response time to access the spill location. Conversely, remote areas not serviced by existing roads would potentially increase the response time to the pipeline spill location. The accessibility to each kilometre segment of the pipeline is ranked according to whether the segment has nearby road access and whether the road is for all-weather or seasonal use only and this ranking was used to modify the consequence score.

5.3 Consequence Scoring

A geographic information system (GIS) was used to map and identify the intersections of spill trajectories with mapped HCAs. The output was used by the Risk Assessment Program to calculate a consequence score for each pipeline kilometre segment according to the logic in Figure 6. Once this is done, the risk assessment results can be queried to determine which HCAs have the highest potential to be affected by a spill.



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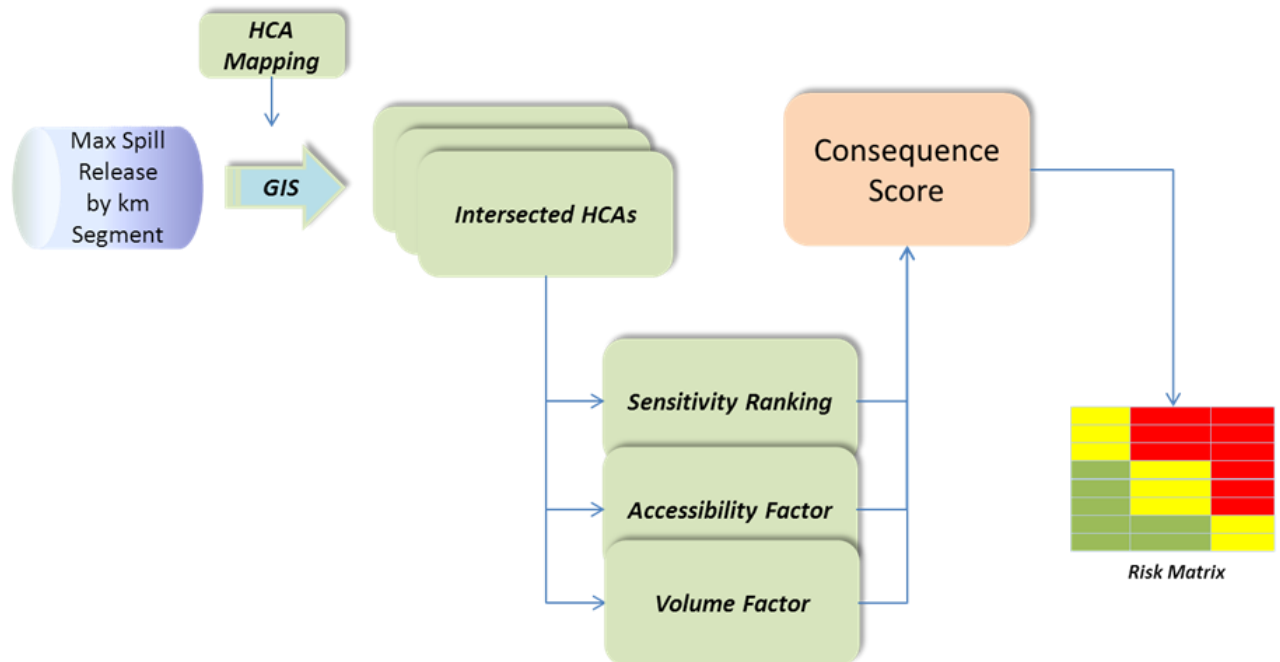


Figure 6: Consequence scoring

There are two parts to consequence scoring and ranking. The first is to derive a score for an individual pipeline segment based on the number of HCAs a spill would affect. The effect is additive. The second part of consequence scoring is to derive a ranking of HCAs based on the potential for the same HCA to be intersected by trajectories from the same 1-km segment of pipeline. While probability for each segment might be relatively low, the resultant probability of an event affecting an HCA will be higher.



5.4 Consequence Scoring by Pipeline Segment

The consequence scoring has identified particular areas along the pipeline which have higher consequences from a full-bore rupture. This assessment is an effective tool to allow Northern Gateway to focus design and mitigation efforts.

Higher consequence watercourses include:

- Athabasca River
- Smoky River
- Missinka River
- Morice River
- Gosnell Creek
- Kitimat River

5.5 High Consequence Area Impacts

Table 5 shows higher consequence watercourses that are potentially affected by the greatest number of segments and the calculated probability for the potential to be affected by a full-bore rupture. This combined probability is a function of the probability of failure assessed for each of the individual segments. All else being equal, more segments means a higher probability and this is reflected in the table.



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Table 5: Unmitigated probability of full-bore rupture for higher consequence watercourses

Higher consequence watercourses	Kilometre segments affected	Probability of full-bore rupture	Return period (years)
Athabasca River	32	8.2E-05	12,000
Smoky River	33	8.7E-05	12,000
Missinka River	41	7.0E-05	14,000
Morice River	24	6.1E-05	16,000
Gosnell Creek	22	4.1E-05	24,000
Kitimat River	29	4.5E-04	2,200

This information will be used to further identify where additional risk mitigation may be required. The Kitimat River has the highest calculated probability of full bore rupture at this time mostly due to the geohazards in the upper Kitimat River valley. Northern Gateway is currently undertaking a detailed assessment of the Kitimat River to identify design and mitigation measures to reduce the risk and consequence in this area. During the detailed design phase other higher consequence locations will similarly be assessed.



5.6 Translation of Consequence Scoring into Consequence Ranking

Consequence scores were translated into a descriptive consequence rank using the categories in Table 6.

Table 6: Consequence matrix

Category	Lower	Moderate	Higher
Description	A full-bore rupture from this segment affects only lower ranked consequence areas. In this category it is likely that the spill only affects one consequence area.	A full-bore rupture from this segment affects low and moderate-ranked consequence areas. There will likely be multiple consequence areas affected.	A full-bore rupture from this segment affects higher-ranked consequence areas. Spills in this category will also affect multiple consequence areas.

The descriptions and criteria for the categories of Lower, Moderate and Higher were established by the Project. The dataset was then divided into the three categories based on the descriptions. While the choice of boundaries is a matter of judgement, there is a good alignment with the definitions.



6. RISK ASSESSMENT

6.1 Methodology

The combination of unmitigated failure frequency and consequence determines the risk severity.

Risk severity is classified using a risk matrix for each kilometre pipeline segment based on combining the frequency of a full-bore rupture for each segment and the resultant HCA consequence score for the modelled spill intersect.

The risk matrix developed for this SQRA is intended to identify high unmitigated risks so that appropriate mitigation measures can be developed and incorporated into the final design.

The risk matrix shown in Figure 7 is employed for the categorization of risk ranking for each kilometre segment along the route.

Frequency (per year)	Consequence			Legend
	Lower	Moderate	Higher	
1E-04 and higher				Higher
1E-04 to 1E-05				Moderate
1E-05 to 1E-06				Lower
below 1E-06				

Figure 7: Risk matrix



6.2 Results – Risk by Pipe Segment

Figure 8 shows the overall number of one kilometre pipeline segments that fall into each unmitigated risk category in the risk matrix. Out of 1,176 pipeline kilometre segments, 894 segments (76%) are classified as lower risk, while 64 segments (5%) classified as higher risk. The remaining 218 segments (19%) fall into the moderate risk category.

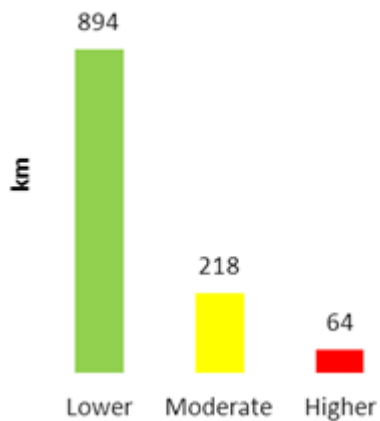


Figure 8: Overall distribution of unmitigated risk severity by kilometre segments



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Figure 9 shows the proportion of unmitigated risk classification by physiographic region. The Alberta Plateau section of B.C. is included with Alberta Uplands in this chart.

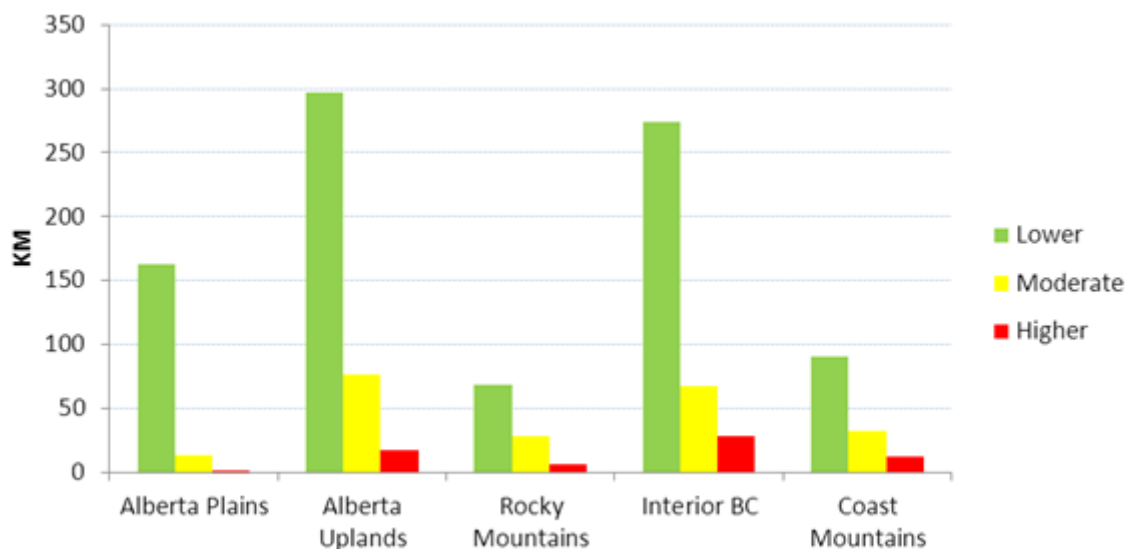


Figure 9: Unmitigated risk classification by physiographic region



7. DISCUSSION OF RESULTS

7.1 Conclusions

This assessment provides an initial identification of areas with the highest risk for the oil pipeline so that appropriate mitigation measures can be developed and incorporated in the final design.

Full-bore rupture frequencies associated with manufacturing defects and corrosion, both internal and external, are expected to be extremely low. Northern Gateway will apply an integrity management program based on Enbridge's existing program as adapted for this project to address these threats.

Frequencies associated with third-party threats are expected to be very low. Northern Gateway will apply an integrity management program based on Enbridge's existing program as adapted for this project to address these threats.

Geohazards in specific areas represent the highest level of threat to the pipeline system. Northern Gateway will design the pipeline system based upon detailed identification of geohazards, specific engineering design, and application of project-specific operating procedures to address these threats.



7.2 Risk-Based Design and Mitigation

As discussed in the response to the JRP (Northern Gateway, March 2011; Internet site), a risk-based approach to design is embedded in the Enbridge engineering standards and is a core feature of design engineering for the Project. While results generated by the risk assessment will be used to guide the final design, some mitigation measures that were identified through the risk assessment process have already been incorporated into the current design. For example, extensive studies relating to geotechnical hazard identification and routing have ensured that many hazards were avoided through the routing process. In addition, a strategic watercourse assessment process was used to screen for environmental, geotechnical and construction risks at important watercourse crossings and to provide site-specific recommendations.

This SQRA was based on assessing risk from a full-bore rupture on the proposed oil pipeline. Northern Gateway recognizes that a release of any magnitude from the pipeline is unacceptable and will undertake additional work during the detailed design phase to apply mitigation to minimize risk of a release of any magnitude.

7.2.1 Kitimat Valley risk reduction planning

The Project is undertaking a more detailed evaluation of higher-risk sections of the Coast Mountain portion of the Route Revision U in response to concerns raised in the JRP proceeding. This evaluation will focus on risk reduction for threats identified, as well as reducing the overall risk along the Kitimat River. It will be a demonstration of the approach that will be taken for other higher risk areas, and inform detailed engineering design in subsequent project phases.



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APPENDIX A: ABBREVIATIONS

Abbreviation	Term
bbl/d	barrels per day
CA	consequence area
HCA	high consequence area
HDD	Horizontal Directional Drilling
ILI	In-Line Inspection
IR	information request
JRP	Joint Review Panel
km	kilometres
km-year	kilometre years
m ³ /d	cubic metres per day
mm	millimetres
NEB	National Energy Board
Northern Gateway	Northern Gateway Pipelines Limited Partnership
NPS	nominal pipe size
OD	outside diameter
PEAA	project effects assessment area
PHMSA	US Department of Transportation Pipeline and Hazardous Materials Safety Administration
RAP	Risk Assessment Program
ROW	right-of-way
SQRA	Semi-Quantitative Risk Assessment
the Project	the Enbridge Northern Gateway Project
this report	this Semi-Quantitative Risk Assessment
WorleyParsons	WorleyParsons Canada Services Ltd.



NORTHERN GATEWAY PIPELINES LIMITED PARTNERSHIP

ENBRIDGE NORTHERN GATEWAY PROJECT

Semi-Quantitative Risk Assessment

SUBMITTED IN RESPONSE TO JOINT REVIEW PANEL INFORMATION REQUEST NUMBER 8.1(B)

APPENDIX B: CONSEQUENCE AREA DEFINITIONS

The following definitions were set out in the Northern Gateway Response to Request for Additional Information, from the Joint Review Panel Session Results and Decision, dated 19 January 2011. Consequence areas were mapped and included in this response.

The decision states the following guideline for consequence areas:

“Consequence areas can be onshore and/or offshore including, but not limited to: wildlife reserves, occupied areas, Indian Reserves, urban areas or towns, water bodies, federal or provincial campgrounds and parks and town water intake locations.”

Northern Gateway has elaborated on this guideline and has described consequence areas according to the following broad categories.

Officially Designated Protected Areas

Federal and provincial protected areas that are shown as consequence areas

- federal national parks,
- provincial parks (in B.C., Class A, B, and C parks),
- provincial conservancies,
- provincial ecological reserves, and
- provincial wildlife reserves.

Campgrounds within federal and provincial parks and protected areas are also included as consequence areas.

Settlements

Human settlements that are shown as consequence areas include hamlets, villages, towns and cities, but not rural areas with sparse and isolated settlements or isolated residential parcels.

Indian Reserves

Areas that are designated by the federal government as Indian reserves under the *Indian Act* are shown as consequence areas.



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Water Use

Licensed sites related to human consumption and other uses (such as industrial, agricultural) are shown as consequence areas.

In Alberta, water licence data were obtained from Alberta Environment (Alberta Environment 2010). This includes both ground water and surface water intake locations for all purposes with sufficient attribute information on licences to allow Northern Gateway to segregate licenses by purpose, such as human consumption. Joint Review Panel Session Results and Decision, dated 19 January 2011 A: Maps Showing Consequence Areas of Potential Volume Releases March 2011, Page 9.

In B.C., water licence data were obtained from GeoBC's data discovery provincial government service (GeoBC 2011). The data included:

- British Columbia points of diversion, such as licensed surface water intake sites for all purposes, but exclude groundwater intakes.
- Water intake extraction points for human consumption, such as for human drinking water systems under the authorization of a Health Authority in B.C. The information includes both surface and groundwater sources but does not include storage or treatment facilities.

Watercourses

Watercourses are shown as consequence areas if they contain fish species that are either at risk or are harvested. Watercourses that do not contain at risk or harvested fish species are shown on the map but not designated as consequence areas.

Information on fish distribution was based on field programs carried out for Northern Gateway from 2005 to 2009 (Whelen et al. 2010), as well as other available data. The presence of species at risk was a criterion for defining a fisheries consequence area, because these species are of management concern and would be vulnerable to contact with oil.

Wildlife

Wildlife habitat is shown as a consequence area if it meets the following conditions:

- It contains species likely to interact strongly with oil. An interaction is considered strong when the species is both likely to contact oil (should a spill occur) and to have elevated mortality rates. Amphibians are considered the group most sensitive to spills, followed by some aquatic birds that actively forage in wetlands (described below).



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- It is likely to have species at risk as per Environment Canada's Committee on the Status of Endangered Wildlife in Canada (COSEWIC) as Endangered, Threatened, or Special Concern (COSEWIC 2008); by B.C. as Blue or Red listed (BC CDC 2008); or by Alberta as At Risk.

The most sensitive stream-dwelling species at risk is likely to be the coastal tailed frog (which is federally listed as Special Concern and Blue-listed in B.C.). Both field data and habitat suitability modelling were used to identify streams with habitat for the coastal tailed frog.

Wetlands

Fens and marshes are shown as consequence areas for two reasons. First, herbaceous and bryophyte cover could be affected by contact with oil and their recovery rate may be slow. Second, these open water wetlands may be important as wildlife habitat, fish habitat or potential rare plant habitat, all of which have unique hydrological regimes.

Wildlife species at risk that use open water include horned grebe, trumpeter swan, white-winged scoter, American bittern, great blue heron, sandhill crane, yellow rail, rusty blackbird, coastal tailed frog, and western toad. Several species at risk use wetlands but forage above water and are less likely to be exposed to oil (such as Nelson's sparrow, Le Conte's sparrow and rusty blackbird). Three ecosystems (bogs, swamps and floodplains) are not considered as consequence areas because they are dominated by tree or shrub species whose root structure would be less affected by an oil spill than lowland types (Walker et al. 1978).

Information on wetlands was developed as part of terrestrial ecosystem mapping (TEM) for the Project. In Alberta, the wetlands are typically mapped according to ecosite phase (Beckingham and Archibald 1996; Beckingham et al. 1996; Wheatley and Bentz 2002). In B.C., wetlands are mapped according to the guide *Wetlands of British Columbia* (Mackenzie and Moran 2004), as well as the Ministry of Forest's *BEC Field Guides* (Banner et al. 1993a, 1993b; DeLong 2003, 2004; DeLong et al. 1990, 1993, 1994). Fens and marshes were mapped in the PEAA from 2008 to 2009 and following standards for TEM in B.C. (RIC 1998).



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ENBRIDGE NORTHERN GATEWAY PROJECT

Semi-Quantitative Risk Assessment

SUBMITTED IN RESPONSE TO JOINT REVIEW PANEL INFORMATION REQUEST NUMBER 8.1(B)

APPENDIX C: LIST OF ATTACHMENTS

This appendix lists attachments to this document.

No.	Description	Filename	Revision
1	Threat Assessment	-	Final
2	Risk Assessment Support Document – Failure Likelihood Assessment	-	Final
3	Data and Assumptions used in Spill Model Analysis for the Northern Gateway Pipeline	-	Final
4	Report on Quantitative Geohazard Assessment	AMEC File: EG0926008 2100 800	Final



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ENBRIDGE NORTHERN GATEWAY PROJECT

Semi-Quantitative Risk Assessment

**SUBMITTED IN RESPONSE TO JOINT REVIEW PANEL INFORMATION REQUEST NUMBER
8.1(B)**

Attachment 1: Threat Assessment

Northern Gateway Pipeline



Threat Assessment

December 23, 2011

Prepared by:



Dynamic Risk Assessment Systems, Inc.

Risk Assessment • Pipeline Integrity • Engineering • GIS • Data Management & Software

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Executive Summary

The primary objective of a threat assessment is to review the attributes for all potential threats to a pipeline system in consideration of the status of the materials, design, construction and operational variables that are associated with the pipeline system of interest. Through this review, the relevance and severity of each threat can be assessed in the context of the operating environment for the pipeline being reviewed.

On December 8, 2011, a Threat Assessment Workshop was conducted on the Northern Gateway pipeline at the Enbridge offices in Edmonton, AB. Those invited were:

- Supervisor, Risk Management Modeling, Enbridge Pipelines, Inc.
- Senior Geotechnical Engineer, AMEC, Inc.
- Senior Geotechnical Engineer, Worley Parsons, Inc.
- Engineer, Enbridge, Inc.
- P/L Integrity Corrosion Specialist, Enbridge Pipelines, Inc.
- Supervisor, Due Diligence, Enbridge Pipelines, Inc.
- Supervisor, Integrity Analysis, Enbridge Pipelines, Inc.
- Manager, Lands & ROW Specialist, Enbridge Pipelines, Inc.
- Senior Land and ROW Specialist, Enbridge Pipelines, Inc.
- Manager, Engineering Construction & Safety, Enbridge, Inc.
- Supervisor, Quality Management, Enbridge Inc.
- Project Engineer and Route Specialist, Worley Parsons, Inc.
- Specialist, Qualifications & Audit Control, Enbridge Pipelines, Inc.
- Contractor, Project Management, Enbridge Inc.
- Manager, O&M Services, Enbridge Pipelines, Inc.

Also in attendance, representing Dynamic Risk were Jim Mihell, and Christian Canto.

During the Threat Assessment Workshop, and during follow-up discussions, all threat attributes were discussed in terms of their relevance as well as in terms of data availability. For failure likelihood estimation, the availability and type of data dictate the specific approach that can be adopted. Therefore, the other primary goal of a threat assessment is to establish candidate approaches for estimating failure likelihood based on the availability, quality, and completeness of the data attributes for each threat.

Analysis that was undertaken subsequent to the Threat Assessment Workshop and follow-up data gathering undertook to review, on a threat-by-threat basis, the factors that influence each threat for the Northern Gateway pipeline.

The threat potential for each threat was made on the basis of a review and analysis of the threat attribute data. Additionally, a characterization of the failure likelihood estimation approach that the available data will lend themselves to was made.

Where appropriate, assumptions that will be incorporated into the quantitative failure analysis have been identified for each threat. Additionally, where mitigation measures and controls will be required in order to ensure that the magnitudes of threats for the Northern Gateway pipeline will not exceed those that are associated with best practices, those mitigation measures and controls and the assignment of responsibility for executing and implementing those measures and controls were listed.

The results of the threat assessment showed that of all threats considered, only two (SCC and 'other' threats) are characterized as negligible (i.e., this threat will not contribute in a significant way to overall risk), provided that the controls and mitigation plans cited are used on the Northern Gateway pipeline.

For the remainder of threats, quantitative estimates of failure frequency will be made. Where possible (i.e., where a limit state model that is supported by probability distributions exist for its input parameters), a reliability approach has been identified as feasible, supported by the data identified in the analysis. These threats include external corrosion, internal corrosion, and third party damage. Quantification of geotechnical and hydrological threats will be made on the basis of the results of a detailed geotechnical and hydrological evaluation that is currently under way. These four threats are considered likely to contribute the most to overall pipeline risk, and are considered to be of first-order concern.

For the characterization of external corrosion and internal corrosion failure likelihood, 'analogue' ILI datasets will be leveraged along with the specific design details (diameter, wall thickness, grade, and operating pressure) of the Northern Gateway pipeline. Under such an approach, it is important to ensure that the analogue datasets are representative (or slightly conservative) relative to the expected corrosion performance of the Northern Gateway pipeline. In this way, the reliability parameters of corrosion feature incident rate, external corrosion feature size distribution, and corrosion growth rate that are obtained from the analogue ILI datasets can be employed, knowing that the critical reliability data that they impart are representative, or conservative. To ensure that this is the case, several criteria were developed for vetting the analogue ILI databases that will be used.

Based on the typical operating performance characteristics of modern transmission pipelines, those threats that are not being quantified using reliability models, (manufacturing defects, construction defects, equipment failure, and incorrect operations) are expected to contribute in a secondary manner to overall pipeline risk. None of these threats lend themselves to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Therefore, for these threats, an attempt will be made to achieve an estimate of failure frequency based on operating incident data. Where possible, the evaluation of threat incidence will be based on pipelines of similar design and operating parameters to the Northern Gateway pipeline.

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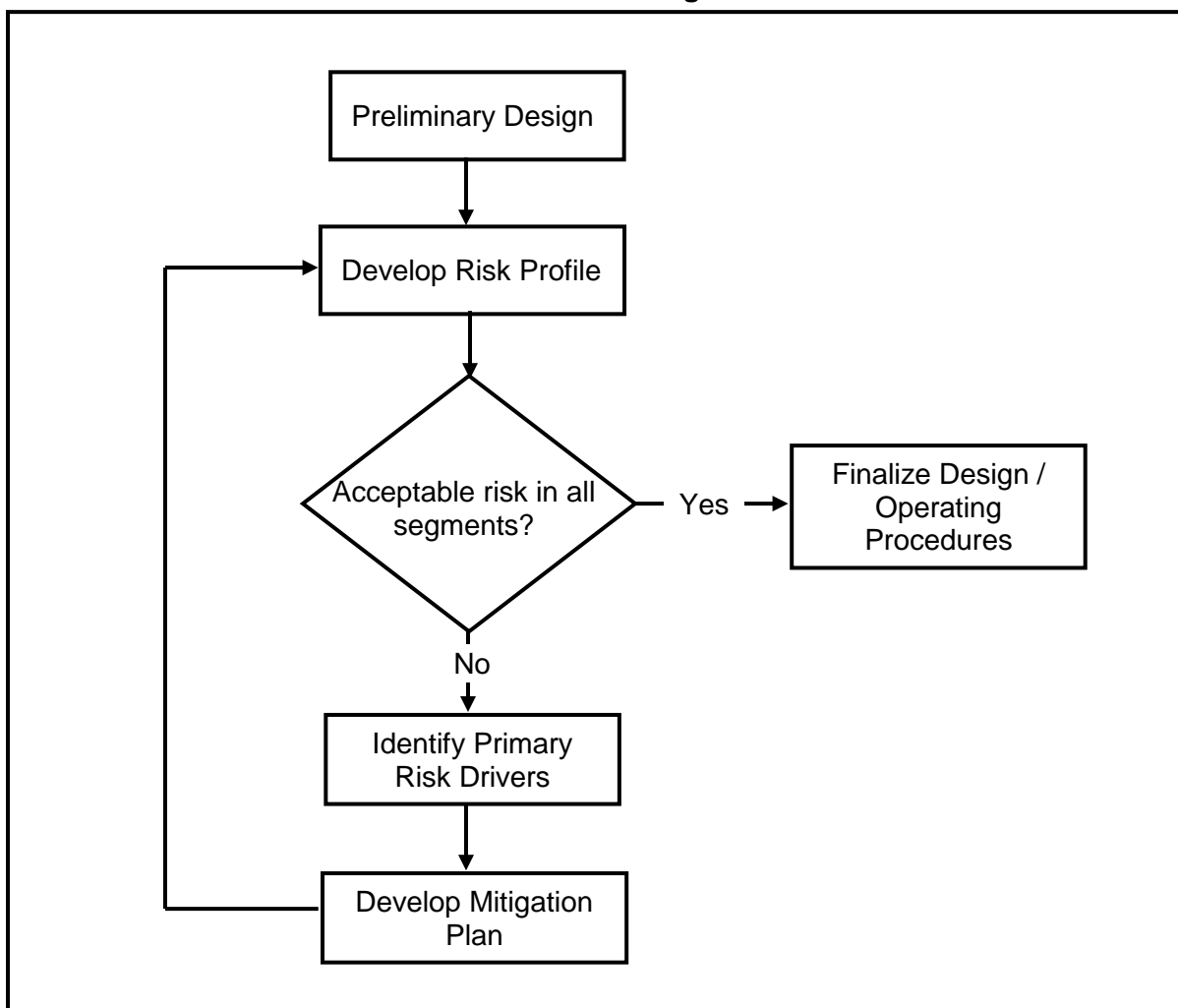
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1. Introduction

A risk-based design process is being undertaken on the Northern Gateway dilbit pipeline, running from Bruderheim, near Edmonton, Alberta, to a new marine terminal in Kitimat, British Columbia to export petroleum. Risk-based design is a process that enables the pipeline design team to minimize risk economically, and to demonstrate safe operations.

The risk-based design approach is summarized in Figure 1.

Figure 1
Risk Based Design



As can be seen from Figure 1, risk-based design is an iterative process, whereby the risk of a preliminary design is reviewed, and an assessment is made as to whether risk objectives are met at all locations along the pipeline. If they are, then the associated design and operating conditions are established as the basis of the finalized design. Otherwise, pipeline segments that are deemed unacceptably high in risk are identified, and mitigation strategies that are appropriate for the primary risk drivers that prevail in regions of unacceptably high risk are developed, and risk is re-evaluated. The process continues until all risk objectives are met. Risk mitigation measures are chosen so that they address the primary risk-drivers identified.

A quantitative risk assessment (QRA) best serves the objectives of a risk-based design, since the risk benefits of implementing a specific mitigation measure can be readily compared against other candidate mitigation measures, thereby enabling the risk performance of a pipeline to be optimized through the judicious selection of design and operating parameters. In addition, a QRA serves the objectives of enabling the performance and operating risk of a new pipeline to be gauged against industry standards and existing pipeline infrastructure.

1.1. QRA Approach

In quantitative terms, risk can be expressed as the product of failure likelihood, and consequences of failure:

$$R = FF \times C$$

Equation 1

Where,

R	= Risk
FF	= Failure Frequency
C	= Consequences

As can be seen from Equation 1, in order to complete a QRA, quantitative estimates of failure likelihood are required. There are two basic approaches for estimating failure likelihood. One method is to use industry incident statistics as the basis for the making the estimate, and the other is to estimate failure likelihood based on a first-principles approach, known as 'reliability methods'.

One of the challenges of employing a quantitative risk assessment on a new pipeline is that industry failure statistics are not directly applicable to modern pipeline designs, materials, and operating (i.e., assessment) practices. A review of industry failure statistics suggests that approximately 90% of pipeline failures occur on pipelines that were installed in the 1970s or earlier. These pipelines were largely developed prior to the advent of several risk-critical technologies, such as:

- Continuous casting of steel slabs;



- Thermomechanical Controlled Processing (TMCP) technology for skelp production;
- High Strength Low Alloy (HSLA) steel design;
- Low sulphur steels;
- Inclusion shape control;
- High toughness steels;
- Implementation of quality systems and the use of highly constrained process control variables during pipe manufacture;
- Highly-constrained mechanized welding processes using low-hydrogen welding processes;
- Phased array ultrasonic inspection and 100% non-destructive inspection;
- High performance coating systems such as three-layer coatings and fusion bonded epoxy coatings;
- Design-phase identification and avoidance of geotechnical hazards through consideration of geotechnical input during routing studies;
- Design-phase identification of internal corrosion threat factors and design of mitigation plans through internal corrosion modeling;
- Identification of HVAC interference effects and development of mitigation plans through diagnostic testing of cathodic protection systems;
- Implementation of Quality Management Systems during design, construction and operations

Because all of the above technologies will be implemented during the design, construction and operation of the proposed Northern Gateway pipeline, the use of industry failure statistics is not a suitable basis for estimating failure rates.

Another disadvantage of using industry failure databases as the basis of a quantitative risk assessment is that they don't address unique site-specific threats, such as geotechnical hazards.

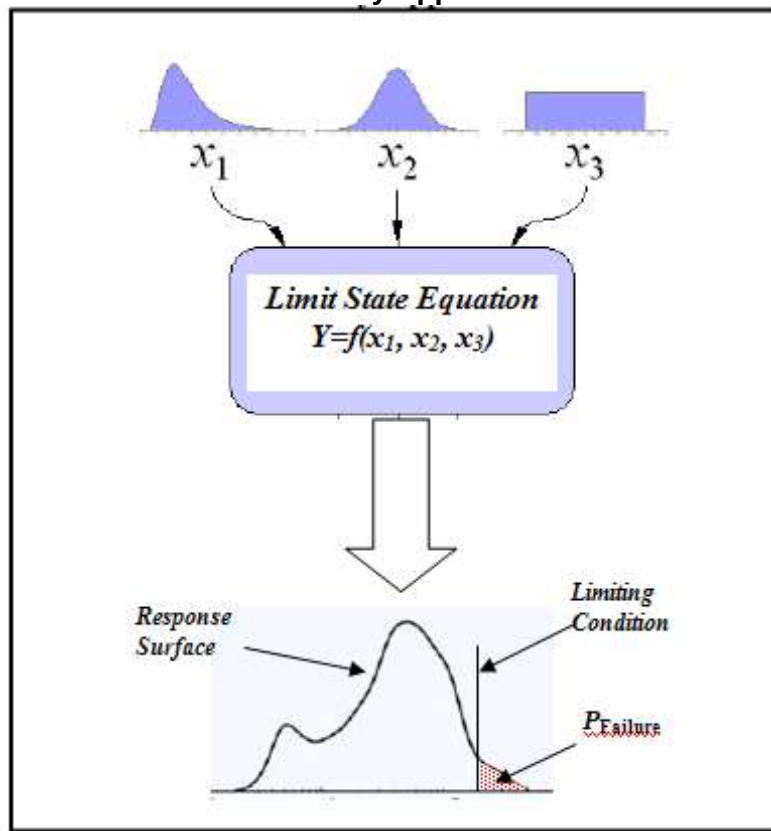
Finally, because the designs of older pipelines were generally not optimized using modern modelling techniques such as overland spill modeling and valve optimization, the consequences of failure in older pipelines, as reported in industry incident databases are often more severe than would be the case in a pipeline that was designed using a modern risk-based design approach.

Reliability methods have been widely adopted in the nuclear and aerospace industry, where they are used to identify and manage threats. In recent years, the pipeline industry has moved towards adopting this as a tool for managing risk and reliability, and pipeline industry research organizations such as PRCI and EPRG have spent hundreds of thousands of dollars in the past several years in developing reliability-based models for various threats. Reliability models employ limit state functions for the specific damage mechanism of interest in which the load variables and resistance variables are characterized in terms of probability density functions. This enables us to use reliability modeling techniques such as Monte Carlo Analysis to characterize the probability of

incurring a failure on a pipeline. Reliability methods provide us with a powerful tool to make accurate, quantitative predictions on likelihood of failure and expected lifespan.

The Figure below illustrates how reliability methods are utilized to quantify the probability of failure, based on a defendable approach:

Figure 2
Reliability Approach



In the pipeline industry, reliability models exist for the most significant threats, including 3rd Party Damage, Internal Corrosion and External Corrosion. In addition, geotechnical threats can usually be characterized in terms of expected magnitude and associated frequency of occurrence, thereby enabling pipeline reliability to be established at each geotechnically-active site.

The basis of every reliability model is a limit state equation that describes the failure conditions for the mechanism being considered. Furthermore, at least one of the input variables to this limit state equation must be characterized as a probability density function, as illustrated in Figure 2. Therefore, a reliability approach is not possible for some threats, such as incorrect operations, where these probability density functions are not available. For these threats (which fortunately usually constitute 2nd-order threats, in terms of failure likelihood magnitude), the only alternative is to employ industry failure statistics, incorporating some measure of compensation (where appropriate) to account for differences in materials, design and operations that are characteristic of modern pipelines.



1.1. The Role of a Threat Assessment in QRA

The primary objective of a threat assessment is to review the attributes for all potential threats to a pipeline system in consideration of the status of the materials, design, construction and operational variables that are associated with the pipeline system of interest. Through this review, the relevance and severity of each threat can be assessed in the context of the operating environment for the pipeline being reviewed.

In the process of undertaking a threat assessment, all threat attributes will be discussed in terms of their relevance as well as in terms of data availability. Specific data sets are required in order to employ a reliability approach to failure likelihood estimation, and the availability and type of data that are available will dictate the specific approach that can be adopted. Therefore, the other primary goal of a threat assessment is to establish candidate approaches for estimating failure likelihood based on the availability, quality, and completeness of the data attributes for each threat.

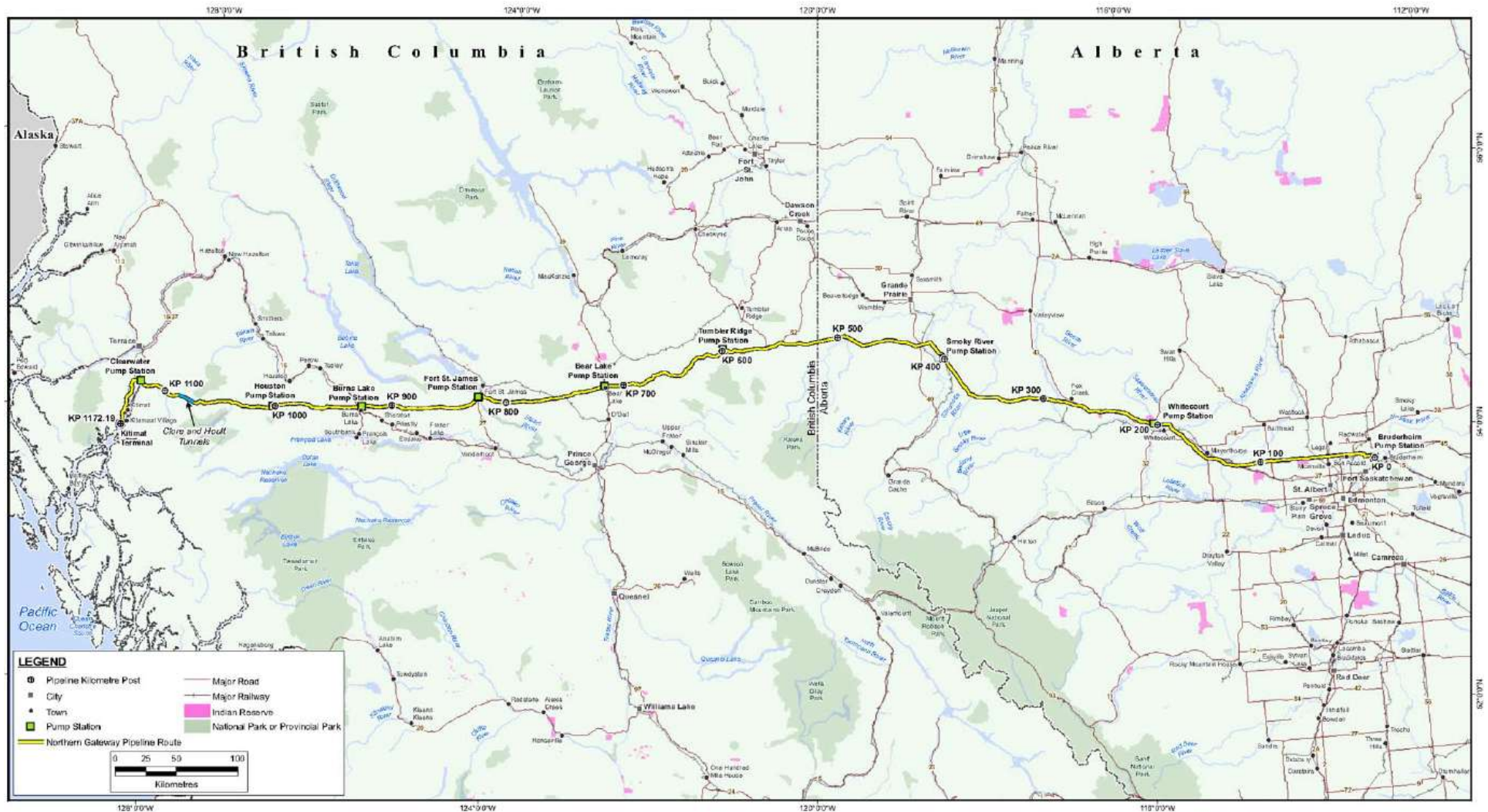


2. Scope

The threat assessment documented in this report was conducted on the NPS 36 dilbit Northern Gateway pipeline, approximately 1,172 km in length that will transport oil from Bruderheim, Alberta to Kitimat, British Columbia. The pipeline route is provided in Figure 3.

The NPS 36 oil pipeline is designed to operate at a maximum design pressure ranging from 8,707 kPa to 16,755 kPa, based on a uniform maximum operating head profile. It will be operated as a low vapour pressure pipeline, with an average annual capacity of 83,468 m³/day (based on 90% theoretical design capacity), or 92,742 m³/day (based on 100% theoretical design capacity).

Figure 3 – Route of Northern Gateway Pipeline



3. Threat Assessment Approach

The threat assessment approach described in Appendix (A) of ASME B31.8S was used as the basis of the Threat Assessment Workshop, with the understanding that some of the evaluation criteria such as year of installation, failure history, etc. are not relevant, given that the pipeline has not yet been built. Although the scope of ASME B31.8S is the management of system integrity of gas pipelines, this Standard was employed as the basis of the threat assessment because the comprehensive list of threats considered in Appendix A of that standard is generally applicable to liquids pipelines.

Under the threat assessment guidelines provided in Appendix (A) of ASME B31.8S, threats are divided into 9 categories:

1. External Corrosion;
2. Internal Corrosion;
3. Stress Corrosion Cracking;
4. Manufacturing Defects;
5. Welding / Fabrication Defects;
6. Equipment Failure;
7. Third Party Damage;
8. Incorrect Operations;
9. Weather Related and Outside Force; and,
10. Other threats

In addition to addressing the relevancy and significance of each of the above threat categories, a review was undertaken of the availability, quality, and completeness of the data attributes for each threat, with respect to the type and viability of reliability approach that might ultimately be employed to quantify the magnitude of failure likelihood for each threat.

A Threat Assessment Workshop was conducted in Enbridge's offices in Edmonton, Alberta on December 8, 2011. Standardized Threat Assessment forms were utilized to focus the discussion during this workshop. The information collected during the Threat Assessment Workshop and from follow-up data collection exercises is presented in the next Section.

4. Data Collection and Assessment

In this Section, the threat attributes for each of the threats listed in Section 3 are discussed on a threat-by-threat basis.

4.1. External Corrosion

A summary of the data review and assessment for this threat is provided in Table 1.

Table 1

Threat Attribute	Data Evaluation	Discussion
Coating Type	<p>Discussion during the Threat Assessment Workshop and a review of the DBM established the following:</p> <ul style="list-style-type: none"> - Line pipe for the pipeline will be coated with fusion-bonded epoxy applied at a coating plant. - The use of a three-layer system consisting of fusion-bonded epoxy, adhesive and polyethylene layers for either a portion or the entire length of the pipeline will be evaluated during the detailed engineering phase. - Field girth welds will be coated with a system compatible with the plant-applied external coating system. - Line pipe for HDD or bored sections of the pipeline will receive an additional abrasion-resistant coating to protect the base coating. - Buried block valve assemblies and other underground appurtenances will be coated with a suitable corrosion control system such as an epoxy/urethane system. 	<p>All coating types being considered for the pipeline can be characterized as high-performance coating systems that form an efficient corrosion barrier, and that resist degradation with time.</p> <p>According to the hydraulic design that is proposed for the mainline, the temperature may reach an annual average temperature of approximately 32°C in the oil pipeline. Furthermore, maximum temperatures in the oil pipeline have the potential to reach as high as 50°C at or near pump station outlets. Therefore, it is imperative that a coating system that is capable of accommodating these temperatures must be specified.</p>
Cathodic Protection	<p>Discussion during the Threat Assessment Workshop and a review of the DBM established the following:</p> <ul style="list-style-type: none"> - The CP system for the pipeline will be designed and installed in accordance with the applicable codes and regulations and Enbridge's engineering standards and specifications. - Ongoing CP monitoring will be in accordance with CSA Z662-07 and Canadian Gas Association (CGA) standard OCC-1-2005. - Where portions of the pipeline will be close to alternating-current power lines, CSA Z662-07 and Can/CSA-C22.3 No. 6 will be followed. - The oil pipeline will share a common RoW with the condensate pipeline, and will be made electrically continuous through continuity bonding. This electrical continuity will provide common CP to both pipelines. The continuity bonding will be provided by means of multiple 	<p>The DBM states that where possible, the route was selected to closely parallel existing infrastructure, primarily other pipelines, but also roads, trails and power lines. While it is too early to identify in detail where the Northern Gateway RoW will have a common boundary with other RoWs, it will be important to identify parallel alignments with HVAC corridors, and to install appropriate induced AC mitigation in these locations during the detailed design phase.</p> <p>Because of the northern latitude of the proposed Northern Gateway pipeline, it will be necessary to ensure that a mitigation plan for</p>

	<p>negative cables at the CP locations and at other intermediate bond locations as needed.</p> <ul style="list-style-type: none"> - Test stations for long-term monitoring of CP levels in accordance with CSA Z662-07 will be installed at appropriate intervals along the pipelines to confirm the effectiveness of the applied CP current and to permit pipeline access for other corrosion control monitoring activities. Test stations will also be installed at cased road and railway crossings and at other existing pipeline crossings, as necessary. - The pipelines will be electrically isolated from the pump stations so that the available pipeline CP current remains with the pipelines. Monolithic (weld-in type) isolators will be installed where the pipelines enter and exit the pump stations. Standard flange insulation kits will be used to isolate drain lines or other piping that may bypass the pipeline insulation. 	<p>tellurics, including consideration of potential-controlled rectifiers, is addressed during the detailed design phase.</p>
Soil Characteristics	<p>The DBM indicates that the pipeline RoW crosses a wide variety of terrain, potentially including Acid-Generating Rock.</p>	<p>Locations of Acid-Generating Rock will be identified and that corrosion mitigation plans will be included in the detailed engineering phase.</p>
Above-ground pipe	<p>The DBM identifies several potential locations of above-ground pipe, including:</p> <ul style="list-style-type: none"> - Aerial crossings of gorges and/or watercourses; and - Two tunnel installations 	<p>It will be necessary to consider factors that might influence the susceptibility to atmospheric corrosion, such as pipe support design, atmospheric coating systems, and atmospheric/buried coating transitions during the detailed engineering design</p>
Casings	<p>The DBM indicates that rather than using casings at crossings of roads and railways, short lengths of heavy-wall pipe will be used. Nevertheless, the use of some casings should be anticipated for bored trenchless crossings, where casings may be used to stabilize the path prior to pulling the pipe through the crossing.</p>	<p>Should casings be used in bored trenchless crossings as a means of stabilizing the path, then measures (such as filling the annulus with corrosion inhibitor) should be considered during the detailed design to accommodate the potential future occurrence of electrolytic and/or metallic shorts.</p>
ILI Data	<p>Although the Northern Gateway pipeline is not yet built, Enbridge Pipelines has identified several ILI data sets that would provide suitable analogs representing modern pipelines using high performance coating systems from which reliability data can be derived.</p>	<p>In order to ensure that the analog ILI data sets are representative or conservative with respect to the corrosion performance of the Northern Gateway pipeline, the above recommendations must be addressed during detailed design.</p>



4.2. Internal Corrosion

Based on interviews conducted during the Threat Assessment Workshop, and an evaluation of data related to the product stream and hydraulic model, an assessment of the internal corrosion potential of the dilbit (oil) pipeline was undertaken. The results of this assessment are detailed below.

4.2.1 Corrosivity of Dilbit Stream

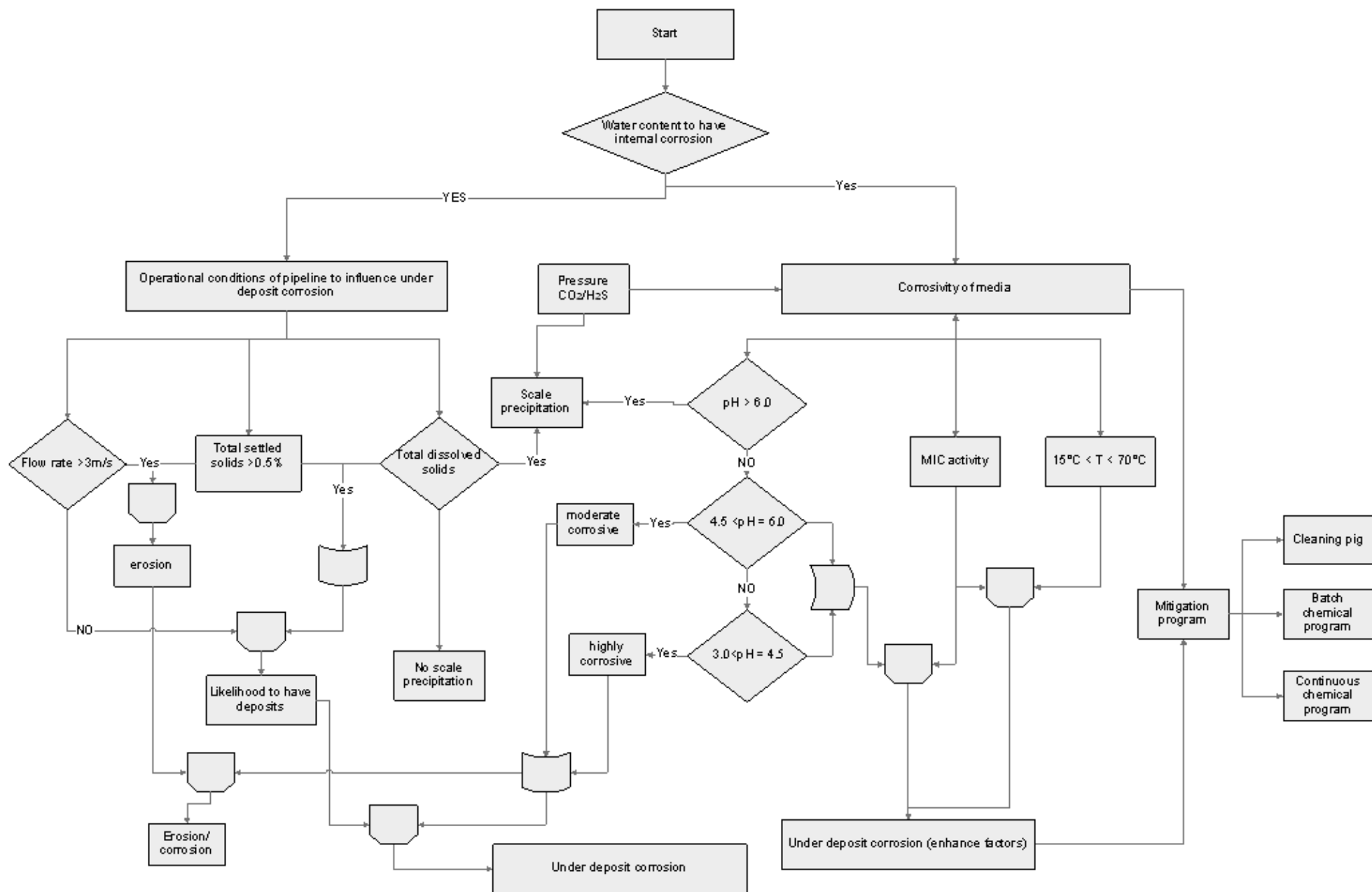
There is some controversy related to the transmission of heavy oil via pipeline and the level of Corrosivity associated with that product. Oil sands oil that is produced in the Athabasca Region of Canada is considered a dense crude oil with an API density of approximately 21. However, during the transportation of this oil, the injection of diluent into the stream results in a reduction in the density and viscosity of the product stream (termed 'dilbit') so that it can be made readily transportable.

The important parameters that should be included in a comparison of the corrosivity of liquid products are:

- a) Water content
- b) Erosion and erosion corrosion (flow velocity)
- c) Temperature
- d) Under-deposit corrosion (flow velocity)
 - a. Deposit of solids
 - b. MIC
 - c. Water chemistry
 - i. Sulphur content
 - ii. Chlorides

The following sections constitute a review of these parameters in the context of a flow chart (see Figure 4) with respect to the Corrosivity of the product that will be transported in the Northern Gateway pipeline.

Figure 4
Flow Chart to Characterize Corrosivity of Liquid Products



4.2.1.1 Water Content

The first variable addressed in the flow chart shown in Figure 4 is water content. As the Northern Getaway oil pipeline is characterized as a transmission pipeline, the tariff amount of bottom sediment and water (BS&W) will be less than 0.5%. This means that even though in small quantities, water will be present in the dilbit stream. The hydraulic model contained in the DBM illustrated that the flow regime for the target flow rate will be fully turbulent. Therefore, the small amount of water that exists in the oil will be fully entrained, and will not stratify.

As discussed above, because of the fully-turbulent flow regime, it is expected that there will not be a tendency for water to stratify.

4.2.1.2 Under-deposit Corrosion

As was reviewed during the Threat Assessment Workshop, the main issue that has been encountered in pipelines transporting products that are similar to dilbit has been associated with under-deposit corrosion.

Deposit of Solids

During the Threat Assessment Workshop it was learned that the amount of solids in the stream represents 60% of the total BS&W tariff value of 0.5 %. This percentage of solids could be deposited in the bottom of the pipeline as a result of gravity setting with fluid dynamics. For example, if the flow velocity is high enough, solids tend to be suspended in the stream as a consequence of turbulence. On the other hand, if the flow velocity is reduced, solids with higher densities than the fluid will have a tendency to be settled at the bottom of the pipeline. As rule of thumb, for large diameter pipelines, it is known that flow velocities lower than 1.2m/s, as well as conditions of intermittent flow direction are associated with accelerated deposit of solids particles.¹ The hydraulic model contained in the DBM illustrated that the fluid velocity of the oil pipeline at ultimate phase target design capacity will be 2.90 m/s. Although this velocity is above the threshold for solid accumulation, with the potential for interrupted flow, it should be expected that these solids will precipitate during extended shut-down conditions. Upon restart, however, these solids should be readily transported away once the velocity threshold is exceeded.

MIC

Under-deposit corrosion can be enhanced if microbially-induced corrosion (MIC) is expected. Figure 4 shows how temperatures between 15 °C and 70 °C can increase MIC activity leading to localized attack. The hydraulic model contained in the DBM illustrated that for the 525 kbpd case in the oil pipeline, the average annual temperature would be within this temperature range across the entire length of the pipeline. These findings suggest that during the operation of the pipeline, flow conditions should be monitored for MIC susceptibility, and that biocides should be considered.

¹ Moghissi, O., Sun, W., Mendez, C., Vera, J., Place, T., "Internal Corrosion Direct assessment Methodology for Liquid Petroleum Pipelines" NACE International Paper 07169, 2007 (Houston:TX)

Chlorides

Besides MIC activity, chloride concentration also plays an important role in the overall corrosion and under-deposit corrosion mechanisms. In respect of the overall corrosion rate, chlorides increase the conductivity of the corrosive solution due to a change in ionic strength, leading to an increase in the corrosion rate. In the under-deposit corrosion mechanism, chlorides can promote the removal of protective scales (if there are any), leading to localized attack. In addition, strong changes in temperature might form hydrochloric acid from the reaction of the chlorides with water vapour. However, pipeline operators have not experienced this phenomenon with temperature changes below 150 °C. The hydraulic model contained in the DBM showed that a temperature change of this magnitude will not occur in the dilbit pipeline.

Sulphur

Sulphur may be co-produced with sour gas and sour oil. As a result of pressure and temperature changes (in most cases a reduction) in the flowing conditions or in shut-in conditions, sulphur may precipitate from polysulphides and cause plugging and / or corrosion problems.

From the corrosion viewpoint, sulphur can increase corrosion in many ways. First, it can break down the protective iron sulphide layers. Second, it can enhance cathodic reactions (polysulphides can consume electrons and can also directly consume electrons via solid state reactions). Third, elemental sulphur also acts as a suspended solid, impairing inhibitor performance by either reacting with inhibitor molecules or by blocking inhibitor adsorption onto the metal surface.

The sulphur percentage in the Northern Gateway dilbit is not higher in comparison with other heavy crude oils. For dilbit operations, sulphur represents a problem only if there is sedimentation of solids and sulphur. As was discussed previously, the turbulent flow regime at which the Northern Gateway pipeline will be operated does not imply accumulation of solids in the bottom of the pipe. While there is potential for the deposition of solids during shut-downs, those solids should be transported away once flow resumes.

Another factor that can promote the deposition of sulphur-containing compounds is temperature. Specifically, sulphur can form hydrogen sulphide (H_2S) if the operating temperature exceeds 200 °C. This scenario is unlikely to occur in the Northern Gateway pipeline because the operating temperature will not exceed the 200°C threshold.

In consideration of the above, it is expected that sulphur-related issues will not contribute in a significant way to the threat of internal corrosion in the dilbit pipeline, and that the amount of sulphur that is present will be readily controlled with an adequate cleaning program.

Erosion Corrosion

As illustrated in Figure 4, erosion-corrosion could be a factor if the flow velocity is higher than 3 m/s and the BS&W is higher than 0.5%. The hydraulic model contained in the DBM shows that neither of these conditions will occur, even at maximum mainline fluid velocities for the dilbit pipeline. Therefore, erosion issues will not likely be a concern.

Temperature Effects

The hydraulic model contained in the DBM considers operating temperatures in the range of 19.3 °C to 40.9 °C, with a design temperature limit of 50 °C at the ultimate flow rate. Nevertheless, the temperature can increase during summer operation to values approaching 50 °C. Changes in temperature can lead to a rapid increase in the corrosion rate if the corrosion mechanism is controlled by diffusion. However, in a pipeline environment, temperature also affects other important driving parameters, such as scale deposition, chemical reactions rates, microbiological activity, and presence of undissociated organic acid (short chain e.g. acetic acid) .

For the Northern Gateway pipeline, the primary corrosive issue is related to under-deposit corrosion mechanisms. The under-deposit corrosion mechanism is mainly driven by the acidification of the media beneath the solid deposit and by the presence of microorganisms. Therefore, the expected changes in temperature will not increase the final corrosivity of the dilbit oil to higher corrosion levels than the already expected.

4.2.2 Summary of Corrosivity Evaluation

The corrosivity of the dilbit oil, based on the tariff parameters, is mainly focused on the under deposit corrosion mechanism. The flow chart in Figure 4 provides a sound basis of comparison for conventional oils with the Northern Gateway dilbit oil based on tariff inputs. As was discussed in this Section, with solids and water (BS&W) limited to 0.5% water and solids should be readily entrained in the flow at the projected turbulent flow regime, given the design flow velocities. This turbulence will act to clean any deposits at the bottom of the line, reducing the potential harmful effects associated with under-deposit corrosion. Also, because of the low BS&W index, erosion is unlikely to present a threat. Special attention should be focused on segments of pipe where accumulation could happen; for example at dead legs, and measures should be taken to avoid such features during the design phase.

Underdeposit corrosion and microbiological activity can be a problem at the temperatures being proposed for pipeline operation (between 15 and 50°C) should deposition of solids ever occur (for example, during extended shut-downs), and so during the operation of the pipeline, flow conditions should be monitored for MIC susceptibility, and biocides should be considered as a preventative measure.

In conclusion:

- The dilbit that is planned to be transported in the Northern Gateway oil pipeline is not more corrosive than other similar heavy crude oils. The operation of this pipeline should incorporate regular cleaning programs and adequate chemical inhibition treatments.
- During the operation of the dilbit pipeline, flow conditions should be monitored for MIC susceptibility, and biocides should be considered as a preventative measure.



4.3. Stress Corrosion Cracking

According to the CEPA Stress Corrosion Cracking Recommended Practice (2nd Edition, December, 2007), the most proven method of reducing SCC initiation on new pipelines is with the use of high performance coatings and effective CP. This document goes on to state that based on industry experience, susceptibility to SCC has been associated with coatings other than the following:

- Fusion bond epoxy (FBE);
- Urethane and liquid epoxy;
- Extruded polyethylene;
- Multi-layer or composite coatings

With respect to coatings, the DBM indicates:

“Line pipe for the pipelines will be coated with fusion-bonded epoxy applied at a coating plant. The use of a three-layer system consisting of fusion-bonded epoxy, adhesive and polyethylene layers for either a portion or the entire length of the pipelines will be evaluated during the detailed engineering phase. Field girth welds will be coated with a system compatible with the plant-applied external coating system.”

Both the FBE and three-layer systems that are being specified for the pipeline are characterized by the CEPA manual as high-performance coating systems, and as such are resistant to the formation of significant SCC. To date, no operating company has ever experienced a failure that was attributed to SCC in a pipeline that was coated with either of these two coating systems.

In order to ensure that SCC remains an insignificant threat on the Northern Gateway pipeline, it will be important to specify that field girth welds and coating repairs are completed with high performance coating systems (i.e., either field-applied fusion bond epoxy, liquid urethane, or liquid epoxy).



4.4. Manufacturing Defects

Historically, failures associated with manufacturing defects have been associated primarily with pipe seam defects (crack, cold lap, misalignment, etc.) and hard spots. Other issues related to pipe manufacture, such as out-of-roundness, out-of-dimensional-tolerance conditions in end preparation, and high hardenability have contributed to field weldability problems, which in themselves have constituted a pipe integrity hazard.

In modern pipe manufacture, with the universal adoption of continuous casting in lieu of ingot casting practices, and with the advent of High Strength Low Allow steel designs, hard spots have been fully eliminated, although for the most part, the remainder of the above-listed issues are still a concern. In addition, in recent years, hydrostatic test failures and dimensional out-of-spec conditions have resulted from the production of pipe that does not meet minimum yield strength criteria.

The best way to safeguard against manufacturing defect related pipeline failures is through the application of carefully designed and executed pipe manufacturing and quality control practices, as dictated by rigorous skelp and pipe mill pre-qualification procedures and pipe purchase specifications.

For the Northern Gateway project, the Canadian SAW Standard EES102 will be applied to submerged arc welded pipe, and the Canadian ERW Standard EES100 will be applied to electric resistance welded pipe.

Vendor pre-qualification will be based on commercial, technical and quality criteria.

In addition, quality and technical assessments will be performed on skelp providers to pipe mills.

The final details of the order, including order-specific properties called out in the data sheet associated with the pipe purchase specification are an output of this process and are attached to the purchase order.

During pipe manufacture, 100% third party inspection will be deployed in accordance with an Inspection and Test Plan that is defined during the materials requisition process, and which mirrors the manufacturer's Inspection and Test Plan, which is reviewed as part of the materials requisition process.



4.5. Construction Defects

Historically, construction defect failures have been associated primarily with welding defects and installation defects such as dents and buckles, which may be associated with improper ditch preparation and backfill, or with the use of excessive tie-in strains.

The mainline welding practices that are being planned for the Northern Gateway pipeline include the use of a mechanized GMAW process. Because this is a low hydrogen welding process, it addresses, to a large extent, the potential for delayed hydrogen cracking on mainline welds. In addition, due to the mechanized nature of this process, welding variables, including joint preparation, line-up practices, wire feed speed, and voltage are all highly controlled, enhancing quality control and reducing joint-to-joint variability. This addresses the potential for excursions beyond the procedural endpoints of the welding procedure specification.

For tie-ins, low hydrogen welding processes (FCAW or LH-SMAW) will be employed for thicknesses in excess of 16 mm, where the potential for delayed hydrogen cracking is the greatest due to higher constraint conditions in heavy-wall pipe. As a further guard against delayed hydrogen cracking, in winter construction, all welds of unequal thickness (i.e., $\Delta t > 1.6$ mm), will be nondestructively inspected after an 18 hour delay.

Phased array ultrasonics (along with possibly radiographic inspection) will be employed as the preferred nondestructive inspection method. This technology readily accommodates a wide variety of inspection angles, and so is ideally suited to the detection of cracks and lack of fusion, which can occur on a variety of planes.

Immediately following installation, a pipe size and deformation (PSD) tool will inspect the pipeline for dents and buckles that might have been created during installation.

In order to address the potential for subsidence in deep excavations during construction, this issue will need to be addressed during the preparation of construction procedure specifications.



4.6. Equipment Failure

Equipment failure is defined in the context of pipeline transmission infrastructure as failures occurring in pressure retaining components other than pipe and fittings. Components that are included in this definition are valves, flanges, gaskets, etc. Risk factors for equipment failure are related to O&M procedures. These procedures detail when and how inspections and maintenance of equipment shall be performed, and what specific action is required.

In order to assess the degree of threat associated with this threat category, a questionnaire was administered during the Threat Assessment Workshop. This questionnaire, and the associated results are provided below:

Table 2

Evaluation of Equipment Mechanical Integrity

Note: This questionnaire should be completed such that high scores correspond to the most favourable outcome in the range of possible outcomes.

The following responses reflect current standard practices at Enbridge – additional or different measures will be investigated during final design.

Question #	Question	Score Range	Response	Actual Score
1	Has a written inspection plan for each operating unit been developed that includes the following elements:			
	a. All equipment needing inspection has been identified?	0-2	Yes	2
	b. The responsibilities to conduct the inspections have been assigned?	0-2	Yes	2
	c. Inspection frequencies have been established?	0-2	Yes	2
	d. The inspection methods and locations have been specified?	0-2	Yes	2
2	e. Inspection reporting requirements have been defined?	0-2	Yes	2
	Is there a written Mechanical Integrity Inspection Plan that includes a formal, external visual inspection program for all major equipment items, where appropriate?	0-2	Yes	2
	a. Are all the following factors considered in the visual inspection program:	0-1	Yes	1
	i. The condition of the outside of the equipment			
	ii. Insulation			
3	iii. Painting/coatings			
	iv. Supports and attachments			
	v. Identifying mechanical damage			
	vi. Corrosion			
	vii. Vibration			
4	viii. Leakage			
	ix. Improper components or repairs			
	Is there a written procedure that requires an appropriate level of review and authorization prior to any changes in inspection frequencies or methods and testing procedures?	0-4	Yes	4
	Have adequate inspection checklists been developed and are they being used?	0-2	Yes – Maximo job plans	2
	Are they periodically reviewed and updated as equipment or procedures change?	0-2	Yes	2
5	Are all inspections, tests and repairs being promptly documented?	0-3	Yes – Maximo	3
	Does the documentation include all of the following information?	0-3		3
	a. The date of the inspection		Yes	
	b. The name of the person who performed the inspection		Yes	
	c. Identification of the equipment inspected		Yes	
	d. A description of the inspection or testing		Yes	

Question #	Question	Score Range	Response	Actual Score
	e. The results of the inspection f. All recommendations resulting from the inspection g. A date and description of all maintenance performed		Yes Yes Yes	
6	Is there a written procedure requiring that all equipment deficiencies identified during an inspection be corrected in a safe and timely manner and are they tracked and followed up to assure completion? a. Is a system used to help determine priorities for action? b. If defects are noted, are decisions to continue to operate the equipment based on sound engineering assessment or fitness for service?	0-5 0-1 0-2	Yes Yes Yes	5 1 1
7	Is there a complete, up-to-date central file for all inspection program information and reports for each facility? Is this file information available to everyone who works in the facility?	0-3 0-2	All in Maximo Yes	3 2
8	Have all employees involved in maintaining and inspecting equipment in a facility been trained in all procedures applicable to their job tasks to ensure that they can perform the job tasks in a safe and effective manner? At completion of the training described above, are formal methods used to verify that the employee understands what he was trained on?	0-5 0-4	Yes Yes	5 5
9	Are training programs conducted for contractor's employees where special skills or techniques unique to a facility are required for these employees to perform a job safely?	0-5	Yes	5
10	Has a schedule been established for the inspection or testing of all pressure relief valves in each facility? Is the schedule being met? Are all inspections and repairs fully documented? Are all repairs made by personnel fully-trained and experienced in relief valve maintenance?	0-3 0-1 0-1 0-1	Yes Yes Yes Yes	3 1 1 1
11	Is there a register of all safety-critical equipment in each facility that is maintained on a permanent basis? In process of completing this, was the list of safety-critical equipment derived from hazard evaluations and risk assessments, using established assessment techniques such as PHAs and HAZOPs?	0-4 0-4	Yes Yes	4 4
12	Does the preventive maintenance program used at each facility meet these criteria? a. All safety-critical items and other key equipment, such as electrical switchgear and rotating equipment, are specially addressed b. Check lists and inspection sheets are being used	 0-1	 Yes	 1

Question #	Question	Score Range	Response	Actual Score
	c. Work is being completed on time	0-1	Yes	1
	d. The program is continuously modified based on inspection feedback	0-1	Yes	1
	e. Repairs are identified, tracked and completed as a result of the PM program	0-1	Yes	1
13	Does each facility have a quality assurance program for construction and maintenance to ensure that: a. Proper materials of construction are being used? b. Fabrication and inspection procedures are proper? c. Equipment is maintained in compliance with codes and standards? d. Flanges are properly assembled and tightened? e. Replacement and maintenance materials are properly specified, inspected and stored?	0-1 0-1 0-1 0-1 0-1	Yes Yes Yes Yes Yes	1 1 1 1 1
14	System Complexity: a. How many commodity origin points are there (select ONE ONLY and assign the appropriate score): i. ≤2 ii. 3-5 inclusive iii. 6-10 inclusive iv. >10 b. How many commodity delivery points are there (select ONE ONLY and assign the appropriate score): i. ≤2 ii. 3-5 inclusive iii. 6-10 inclusive iv. >10 c. How would you describe the pipeline as it pertains to product flow (select ONE ONLY and assign the appropriate score): i. Dedicated ii. Batched iii. Batch-to-batch d. Who controls line operations (select ONE ONLY and assign the appropriate score): i. Company ii. Company Affiliate iii. 3 rd Party e. Does the line have multiple operators (select ONE ONLY and assign the appropriate score): i. Yes ii. No f. How are operations controlled (select ONE ONLY and assign the appropriate score): i. Locally ii. Remotely	3 2 1 0 3 2 1 0 2 1 0 2 1 0 0 2 2 0	One for each pipeline One for each pipeline Diluent line will be dedicated – Crude line probably be batched Company No Remotely	3 3 1 2 0
Score Range		0-92		89



4.7. Third Party Damage

Pipeline reliability, expressed in terms of susceptibility to failure due to 3rd Party Damage has been documented in the literature². In this respect, failure susceptibility due to 3rd Party Damage can be established as the product of two independent variables; the frequency of incurring a hit by heavy equipment, and the probability of failure given such a hit. The susceptibility to failure for the Northern Gateway pipeline will be quantified as a function of these two parameters during the detailed Quantitative Risk Assessment. The latter of the above two variables can be determined as a function of pipe design and material properties. Impact frequency due to external interference has been characterized in terms of damage prevention factors; specifically:

- Type of Land use
- One-call system availability and promotion
- Placement frequency of pipeline marker signs
- Use of buried marker tape at crossings
- 3rd Party requirements regarding notification of intent to excavate
- Patrol frequency
- Response time for locate requests
- Pipeline locating methods used
- Pipeline marking methods used
- Depth of cover

A review of the above-listed damage prevention factors for the Northern Gateway pipeline was completed, based on an interview that was conducted during the Threat Assessment Workshop. The results of this interview are summarized in Table 3.

² Chen, Q., and Nessim, M., "Reliability-Based Prevention of Mechanical Damage", EPRG/PRCI Proceedings of the 12th Biennial Joint Technical Meeting on Pipeline Research, May, 1999, Paper 25.

Table 3

Table 3

Variable	Characterization / Data Availability																															
Land Use (Commercial / Industrial / High-density Residential / Low-density Residential / Agricultural / Remote)	The pipeline alignment is largely rural / non-developed, with the exception of the beginning and end of the pipeline route – particularly in the vicinity of Edmonton, Whitecourt, and Kitimat, as well as in the vicinity of Burns Lake. The alignment within B.C. is for the most part remote. For the purposes of the quantitative risk assessment, land use characterizations can be obtained from the alignment and associated aerial imagery.																															
Method of one-call advertising	Northern Gateway will be a member of One-Call in British Columbia. One-Call does its own promotion throughout B.C. In addition, it is Enbridge’s practice to notified by direct mail-outs and direct door-to-door contact for people in the vicinity of the RoW. In addition, municipalities are notified regarding call-before-dig requirements, and excavators are contacted by mail-outs. Additionally, community meetings and seminars are held.																															
Signage Placement	Signs placement will be undertaken in accordance with the requirements of CSA Z662-11. They will be placed at all roadway, railway, watercourse and fence line crossings. Additional signage is added in areas of utility corridors.																															
Use of buried marker tape	Enbridge does not use buried marker tape.																															
Patrol Frequency	Aerial patrols are conducted at 2-week intervals																															
Response time to notification of intent to excavate	2-3 days																															
Marking and locating methods	For excavations within 30 m, Enbridge’s procedures call for a site meeting and written approval. Pipelines are located by GPS coordinates, plus a transmitter / receiver set. The boundary of the RoW is staked in pink, and if works are to be conducted within the RoW, the pipeline alignment is staked in yellow, and site supervision is required.																															
Depth of cover	<div>Depth of cover requirements are as follows:</div> <table><tr><th rowspan="2">Location</th><th colspan="3">Minimum Depth of Cover (m)</th></tr><tr><th>Construction Grade</th><th>Centreline of Road or Railway Bed</th><th>Rock Ditch</th></tr><tr><td>General</td><td>0.9</td><td>N/A</td><td>0.6</td></tr><tr><td>Paved road</td><td>1.2</td><td>1.5</td><td>1.2</td></tr><tr><td>Improved road</td><td>1.2</td><td>1.2</td><td>1.2</td></tr><tr><td>Access road or trail</td><td>0.9</td><td>1.2</td><td>0.6</td></tr><tr><td>Railway</td><td>2.0</td><td>3.05</td><td>2.0 (3.05 for railways)</td></tr><tr><td>Watercourse</td><td>1.2</td><td>N/A</td><td>0.6</td></tr></table>	Location	Minimum Depth of Cover (m)			Construction Grade	Centreline of Road or Railway Bed	Rock Ditch	General	0.9	N/A	0.6	Paved road	1.2	1.5	1.2	Improved road	1.2	1.2	1.2	Access road or trail	0.9	1.2	0.6	Railway	2.0	3.05	2.0 (3.05 for railways)	Watercourse	1.2	N/A	0.6
Location	Minimum Depth of Cover (m)																															
	Construction Grade	Centreline of Road or Railway Bed	Rock Ditch																													
General	0.9	N/A	0.6																													
Paved road	1.2	1.5	1.2																													
Improved road	1.2	1.2	1.2																													
Access road or trail	0.9	1.2	0.6																													
Railway	2.0	3.05	2.0 (3.05 for railways)																													
Watercourse	1.2	N/A	0.6																													
RoW Condition	RoW will be maintained regularly. No encroachments will be allowed.																															



4.8. Incorrect Operations

Incorrect Operations failure is defined in the context of pipeline transmission infrastructure as failures that have causal factors that are related to design, as well as operation and maintenance procedures. Risk factors for Operations failure are related to the following considerations:

- Design-related:
 - Hazard identification
 - Potential to exceed maximum operating pressure
 - Safety systems
 - Material selection
 - Checks
- Operations / Maintenance related:
 - Operating procedures
 - Management of change
 - SCADA and communications
 - Drug testing
 - Safety programs
 - Surveys, maps and records
 - Training
 - Mechanical error preventers

In order to assess the degree of threat associated with this threat category, a questionnaire was administered during the Threat Assessment Workshop. This questionnaire, which addresses process-related and design-related issues that are relevant to the Northern Gateway pipeline as listed above, is provided below, along with the associated results.

Table 4
Operations Questionnaire

Contents

Section	Subject	Title	Questions	Possible Points
1.1	Design	Hazard Identification	3	3
1.2		MAOP Potential	1	12
1.3		Safety Systems	1	10
1.4		Material Selection	2	2
1.5		Checks	1	2
2.1	Operations	Operating Procedures	7	7
2.2		Management of Change	7	7
2.3		SCADA/Communications	1	3
2.4		Drug Testing	2	2
2.5		Safety Programs	1	2
2.6		Surveys/Maps/Records	2	5
2.7		Training	10	10
2.8		Mechanical Error Preventers	5	11
Total			43	76

Notes:

1. Survey questions for all topics other than Management of Change were based on the Incorrect Operations approach contained in "Pipeline Risk Management Manual", 3rd Edition [Muhlbauer, W.K.]. Management of Change approach was based on API RP 581 Part 2 "Risk Based Inspection Technology" – Annex 2.A – Management Systems Workbook.
2. Scores are assigned such that higher scores are associated with the most favourable response.

Question #	Question	Score Range	Response	Actual Score
1	Design			
1.1	<u>Hazard Identification</u> a. Has a threat assessment been performed that entertains all possible threats? c. Have possible hazards and risks associated with the work been identified through studies such as HAZOP, risk assessment, or reliability analysis? d. Are the results of the above studies available in documented form?	1 1 1	Yes Yes Yes	1 1 1
1.2	<u>MAOP Potential</u> Characterize the ease with which MAOP could be reached on the pipeline system (select <i>one</i> response only): a. Routine. Routine, normal operations could allow the system to reach MAOP. Overpressure would occur fairly rapidly due to incompressible fluid or rapid introduction of relatively high volumes of compressible fluids. Overpressure is prevented only by procedure or single-level safety device. b. Unlikely. Overpressure can occur through a combination of procedural errors or omissions, and failure of safety devices (at least two levels of safety). c. Extremely Unlikely. Overpressure is theoretically possible (sufficient source pressure), but only through an extremely unlikely chain of events including errors, omissions, and safety device failures at more than two levels of redundancy. d. Impossible. Overpressure cannot occur, under any conceivable chain of events.	0 5 10 12	Based on a Windows-based trainer developed by a third party engineering firm, which simulates the operation of the Northern Gateway pipeline, simulations were performed on the following scenarios, including elevation profile considerations: - Maximum flow - Minimum flow - Station lock-out / ESD (including downstream of greatest elevation change) - Mainline RSV closures - Kitimat closure - Bruderheim station lockout - Column separation Transient simulation has not been completed at this time, but final design will be based on transient simulations. Redundant communication systems (satellite vs ground-based) systems will be adopted.	5
1.3	<u>Safety Systems</u> Describe the safety systems that are in place (select <i>one</i> response only): a. No Safety Devices Present. No safety devices are present to prevent overpressure. b. On Site, One Level. A single on-site device offers protection from overpressure. c. On Site, ≥2 Levels. Two or more independent on-site devices offer protection from overpressure. d. Remote, Observation Only. Pressure is monitored from a remote	0 3 6	- Redundant pressure transmitters sending pressure to SCADA - PLC programs (local) - Allowable pressure limits (calculated pressure limits based on elevation profile) linked to station shut-down, Linked to PLC	

Question #	Question	Score Range	Response	Actual Score
	location. Remote control is not possible, and automatic overpressure protection is not present. e. Remote, Observation and Control. Pressure is monitored from a remote location. Remote control is possible, and automatic overpressure protection is not present. f. Non-Owned, Active Witnessing. Overpressure prevention devices exist, but are not owned, maintained, or controlled by the owner of the equipment that is being protected. The owner takes steps to ensure that the safety device(s) is properly calibrated and maintained by witnessing such activities. g. Non-Owned, No Involvement. Overpressure prevention devices exist, but are not owned, maintained, or controlled by the owner of the equipment that is being protected. The owner does not take steps to ensure that the safety device(s) is properly calibrated and maintained by witnessing such activities. h. Safety Systems Not Needed. Safety systems not needed because overpressure cannot occur.	1 3 -2 -3 10	logic, linked to line pressure monitor program - Mainline Pressure relief at Kitimat - Transient mitigation to be determined during detailed design, including consideration for locating surge accumulators along the length of the pipeline - Consideration for installation of VFDs with pressure control valves at each station (to be determined during detailed design)	3 (could be re-set to 6 if VFDs with press. control valves installed at each station)
1.4	<u>Materials Selection</u> Are design documents available that illustrate that all piping systems were designed with consideration given to all anticipated stresses? Do control documents, including material specifications and design drawings for all systems and components exist and maintained in an up-to-date manner?	1 1	These documents will be made available following detailed design. Yes – this reflects current Enbridge practice.	1 1
1.5	<u>Checks</u> Do procedures exist that require design calculations and decisions to be checked by a licensed professional engineer at key points during the design process?	2	Yes	2
2	Operation			
2.1	<u>Operating Procedures</u> Do written procedures covering all aspects of pipeline operation exist? Are these procedures actively used, reviewed, and revised? Are copies of these procedures available at field locations? Does a protocol exist that specifies the responsibility for procedure development and approval? Does a protocol exist that specifies how training is performed against these procedures? Does a protocol exist that specifies how compliance to these procedures is verified? Does a document management system exist that ensures version control, and proper access to the most current procedure documents?	1 1 1 1 1 1 1	Yes Yes Yes Yes Yes Yes	1 1 1 1 1 1
2.2	<u>Management of Change</u> Is there a written MOC procedure that must be followed whenever processes, procedures or physical assets are changed? Are authorization procedures clearly stated and at an appropriate level?	1 1	Yes Yes	1 1

Question #	Question	Score Range	Response	Actual Score
	Do physical changes, changes in operating conditions, and changes in operating procedures invoke the MOC procedure?	1	CCO: Yes LP Operations: Yes – inconsistently used at the moment, and is in the process of being improved	0
	Is there a clear understanding of what constitutes a ‘temporary change’ and does the MOC procedure address temporary changes?	1	CCO: Yes LP Operations: Yes – inconsistently used at the moment, and is in the process of being improved	0
	Are temporary changes tracked to ensure that they are either removed after a reasonable period of time or reclassified as permanent?	1	Yes	1
	Do the MOC procedures specifically require the following actions whenever a change is made to an operating procedure? <ul style="list-style-type: none"> Update all affected operating procedures 		Cross-functional operating procedure changes are not consistently reviewed between different operational stakeholders	
	<ul style="list-style-type: none"> Update all affected maintenance programs and inspection schedules 		Not Consistently	
	<ul style="list-style-type: none"> Modify drawings, statement of operating limits, and any other safety information affected? 		Not Consistently	
	<ul style="list-style-type: none"> Notify all operations and maintenance employees who work in the area of the change, and provide training as required 	1	Not Consistently	0
	<ul style="list-style-type: none"> Review the effect of the proposed change on all separate but interrelated procedures 		Not Consistently	
	When changes are made in operating procedures, are there written procedures requiring that the impact of these changes on the equipment and materials of construction be reviewed to determine whether they will cause any increased rate of deterioration or failure, or will result in different failure mechanisms in the equipment?	1	No – not at the moment	0
2.3	<u>SCADA / Communications</u> Describe the SCADA / Communications systems that are in place (select <i>one</i> response only): a. Level 1. No SCADA system exists, or is not used in a manner that promotes human error reduction. b. Level 2. Some critical activities are monitored; field actions are informally coordinated through a control room; system is at least	0		

Question #	Question	Score Range	Response	Actual Score
	80% operational. c. Level 3. Most critical activities are monitored; field actions are usually coordinated through a control room; system up-time exceeds 95%. d. Level 4. All critical activities are monitored; all field actions are coordinated through a control room; SCADA system reliability (measured in up-time) exceeds 99.9%.	1 2 3	d. Level 4	3
2.4	<u>Drug Testing</u> Does a drug testing program exist that applies to employees who play substantial roles in pipeline operations? Does the testing program incorporate elements of random testing, testing for cause, pre-employment testing, post-accident testing, and return-to-work testing?	1 1	Yes – HR-18 All the above, except random testing	1 0
2.5	<u>Safety Programs</u> Does the company's safety program incorporate the following elements? (award partial marks for compliance with only a portion of the elements): <ul style="list-style-type: none"> • Written company statement of safety philosophy • Safety program designed with high level of employee participation • Strong safety performance record • Good attention to housekeeping • Signs, slogans, etc. to show an environment tuned to safety • Full-time safety personnel 	2	Yes Yes Yes Yes Yes Yes	2
2.6	<u>Surveys, Maps, Records</u> Are surveys such as those listed below conducted on a regular basis? (award partial marks for compliance with only a portion of the elements): <ul style="list-style-type: none"> • Close interval pipe-soil surveys • Coating condition surveys • Water crossing surveys • ILI assessments • Population density surveys • Depth of cover surveys • Patrols (aerial or ground-based) Are detailed, clear maps and records updated regularly, and are they available to all operations staff?	5	Yes Yes – each time an excavation is performed, plus annual surveys on above-ground piping Yes Yes Yes Yes Yes	5
2.7	<u>Training</u> Evaluate the operator training program in terms of the following elements: a. Minimum training requirements are documented b. Incorporates testing c. Covers the following: i. Product characteristics ii. Pipeline material stresses iii. Pipeline corrosion	2 2 0.5 0.5 0.5	Yes Yes Yes No Yes	2 2 0.5 0 0.5

Question #	Question	Score Range	Response	Actual Score
	iv. Control and operations	0.5	Yes	0.5
	v. Maintenance	0.5	Yes	0.5
	vi. Emergency drills	0.5	Yes	0.5
	c. Training is job-procedure specific	2	Yes	2
	d. Incorporates requirements for scheduled re-training	1	Yes	1
2.8	<u>Mechanical Error Preventers</u> Evaluate the availability and effectiveness of the following devices designed to prevent operator error:			
	a. Three-way valves with dual instrumentation. Three-way valves installed between instruments and pipeline components to facilitate the isolation of instruments for maintenance, while preventing the accidental isolation of the instrument.	4	Yes	4
	b. Lock-out devices. Installed on safety-critical valves (e.g., during blow-down and repair)	2	Yes	2
	c. Key-lock Sequence Programs. If a job procedure calls for several operations to be performed in a certain sequence, and deviations from that prescribed sequence may cause serious problems, a key-lock sequence program may be employed to prevent any action from being taken prematurely.	2	Yes	2
	d. Computer permissives. Electronic equivalent to key-lock sequence programs.	2	Yes	2
	e. Highlighting of critical instruments. e.g., painting critical valves with specific colors.	1	Yes	1
Score Range		0-76		56.5



4.9. Geotechnical / Hydrological Forces

Failures that are attributed to geotechnical and hydrological forces are typically associated with outside force events such as subsidence, earth movement, seismic activity, floods, stream erosion, and rock fall. These threats are highly site-specific in nature. In order to assess the degree of threat that a pipeline will be exposed to, a thorough evaluation of all information along the length of the pipeline must be completed. Typically, the collection and review of this information is completed in two stages; the first stage being a desktop exercise, that focuses on published information, such as soils maps, topographic maps, hydrological maps, pipeline alignment sheets, incident reports related to ground movement, hydrological events, and floods, studies, texts, and engineering reports. From this first stage of information gathering and review, potential hazard sites are identified. The second stage of information gathering and review involves data collected from site visits. Such data might include evidence of ground movement, such as slumping, cracks in soil, tilted trees, trees with diverted growth orientation, rock fall, flood marks, scour marks, etc. Where necessary, instrumentation such as slope inclinometers might be installed and monitored. On the basis of the above, the understanding of outside force mechanisms is refined.

Only once the above information is collected and analyzed can the extent of outside force threats, including the potential magnitude of movement, and estimates of movement frequency be established. Outside force mitigation plans are developed on basis of this information. The preferred mitigation strategy is threat avoidance, either by diverting the alignment or by deviating below slip zones and scour zones. In some cases, threats cannot be completely avoided, and other measures, such as long-term monitoring plans, shoring, and other forms of stabilization must be considered.

The above information gathering and mitigation plan is currently ongoing, and at this point it is premature to identify specific sites, mitigation plans, and estimates of outside force frequency and magnitude. This information will be made available in time for the quantitative risk assessment, and the mitigation plans will be incorporated into the detailed design.



4.10. Other Threats

During the Threat Assessment Workshop, an open discussion was held to identify potential threat mechanisms that don't fall into one of the nine categories listed above. The following potential threat mechanisms were identified:

4.10.1 External Loading at Aerial Crossing Locations

Pipeline aerial structures (bridge supports) will be used in four areas, as required due to slope constraints. Considerations for external loading, such as wind loading will be addressed during detailed design.

4.10.2 Forest Fires

As with all pipelines that traverse through forested areas, there is potential for forest fires to affect pipeline operations. Where a pipeline is buried in a cleared right-of-way, forest fires do not constitute a significant loss-of-containment hazard in and of themselves, since the right-of-way acts as a fire break, and the ground cover acts to insulate the pipeline. Fire breaks will need to be installed around above-ground installations, such as valve sites, aerial crossings, and these will need to be addressed during detailed design.

5. Assessment of Threat Potential and Approach

In this Section, an assessment of threat potential is made on the basis of a review and analysis of the data in the preceding Section. Additionally, a characterization of the failure likelihood estimation approach that the available data will lend themselves to was made. The characterization of approach contained in this Section will be general in nature. For the detailed description, reference should be made to the quantitative failure likelihood report.

Where appropriate, assumptions that will be incorporated into the quantitative failure analysis have been identified for each threat. Additionally, where mitigation measures and controls will be required in order to ensure that the magnitudes of threats for the Northern Gateway pipeline will not exceed those that are associated with best practices, those mitigation measures and controls and the assignment of responsibility for executing implementing those measures and controls were listed.

5.1. External Corrosion

5.1.1 Threat Potential

It is expected that the pipeline will have some degree of exposure to the threat of external corrosion, and therefore the threat potential for external corrosion must be included in the quantitative failure frequency estimate.

5.1.2 Approach

As was highlighted in Section 1.1, using industry failure statistics as the basis of a quantitative estimate of failure likelihood is not desirable from several perspectives. Additionally, as with all time-dependent threats, the use of industry failure statistics does not adequately address the fact that the threat of external corrosion failure will initially be zero, and will rise over time.

A reliability approach is therefore being proposed which leverages existing ‘analogue’ ILI datasets along with the specific design details (diameter, wall thickness, grade, operating pressure) of the Northern Gateway pipeline. Under such an approach it is important to ensure that the analogue datasets are representative (or slightly conservative) relative to the expected external corrosion performance of the Northern Gateway pipeline. In this way, the reliability parameters of external corrosion feature incident rate, external corrosion feature size distribution, and external corrosion growth rate that are obtained from the analogue ILI datasets can be employed, knowing that the critical reliability data that they impart are representative, or conservative. To ensure that this is the case, the following measures should be adopted.

Table 5
External Corrosion Measures

Threat Factor	Area of Concern	Controls	Action
Mainline Coating Type	The mainline external coating system used in the pipeline from which the analogue ILI data are taken should be representative or conservative, relative to the expected corrosion coating performance on the Northern Gateway pipeline.	An analogue ILI dataset that is representative of FBE coating systems will address this issue.	To be addressed during selection of analogue ILI database
Field Joint Coating	The field joint external coating system used in the pipeline from which the analogue ILI data are taken should be representative or conservative (but not too conservative), relative to the expected corrosion coating performance on the Northern Gateway pipeline.	Ensure that Northern Gateway Pipeline specify high performance coating systems for field joint coatings (i.e., field-applied FBE, liquid epoxy, or liquid urethane)	To be addressed by Northern Gateway purchase specifications and detailed design
		An analogue ILI dataset that is representative of high performance field joint coating systems will address this issue. If this cannot be done, external wall loss features that are associated with girth welds will not be considered in the analysis.	To be addressed during selection of analogue ILI database and / or during quantitative analysis
Temperature effects on external coatings	Operating temperatures that exceed the maximum temperature rating of the mainline and field joint coating systems can result in significantly degraded coating performance over time	Ensure that coating systems that are specified for mainline and field girth welds are rated to withstand the expected maximum operating temperatures of the Northern Gateway Pipeline (50°C)	To be addressed by Northern Gateway purchase specifications and detailed design
		Ensure that the analogue ILI dataset is representative of pipeline that have not been operated above the maximum temperature rating of either the mainline or field girth weld coating systems.	To be addressed during selection of analogue ILI database
Cathodic Protection	Ensure that CP performance in pipeline from which analogue ILI dataset is obtained is representative of CP performance expected in Northern Gateway pipeline.	Ensure that CP systems for Northern Gateway pipeline are designed and operated in accordance with the requirements of CSA Z662 and OCC-1.	To be addressed by Northern Gateway detailed design, and in operating procedures.

		Identify potential sources of interference (such as from induced AC power lines), and incorporate appropriate mitigations into cathodic protection systems	To be addressed by Northern Gateway detailed design, and in operating procedures.
		Ensure that a mitigation plan for tellurics, including consideration of potential-controlled rectifiers, is addressed during the detailed design phase.	To be addressed by Northern Gateway detailed design, and in operating procedures.
		Ensure that the analogue ILI dataset is representative of pipeline that have not been operated outside of cathodic protection potential criteria.	To be addressed during selection of analogue ILI database
Soil Characteristics	Ensure that soil characteristics in pipeline from which analogue ILI dataset is obtained is representative of soil characteristics expected in Northern Gateway pipeline.	Identify any locations of acid-generating rock, and formulate appropriate mitigation plans where it exists along the pipeline right-of-way.	To be addressed by Northern Gateway detailed design
		Ensure that the analogue ILI dataset is not representative of unusual soil conditions or aggressiveness	To be addressed during selection of analogue ILI database
Above-ground pipe	Ensure that sections of above-ground pipe at aerial crossings, or within the tunnels do not constitute increased levels of external corrosion threat	Consider factors that might influence the susceptibility to atmospheric corrosion, such as pipe support design, atmospheric coating systems, and atmospheric/buried coating transitions during the detailed engineering design	To be addressed by Northern Gateway detailed design
Casings	Ensure that casings do not constitute increased levels of external corrosion threat. The use of some casings should be anticipated for bored trenchless crossings, where casings may be used to stabilize the path prior to pulling the pipe through the crossing.	Measures (such as filling the annulus with corrosion inhibitor) should be considered during the detailed design to accommodate the potential future occurrence of electrolytic and/or metallic shorts.	To be addressed by Northern Gateway detailed design

ILI Data	Potential for manufacturing defects to be misinterpreted as corrosion defects, leading to unrealistically high corrosion feature incidence rates and aggressive apparent growth rate distributions	Utilize multiple 'matched' ILI data to negate the effect of manufacturing defects.	To be addressed during selection of analogue ILI database
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5.2. Internal Corrosion

5.2.1 Threat Potential

The product that will be transported by the Northern Gateway Pipeline has the potential to cause internal corrosion, and so it is expected that the pipeline will have some degree of exposure to the threat of internal corrosion, and therefore the threat potential for internal corrosion must be included in the quantitative failure frequency estimate.

5.2.2 Approach

As was highlighted in Section 1.1, using industry failure statistics as the basis of a quantitative estimate of failure likelihood is not desirable from several perspectives. Additionally, as with all time-dependent threats, the use of industry failure statistics does not adequately address the fact that the threat of external corrosion failure will initially be zero, and will rise over time.

A reliability approach is therefore being proposed which leverages existing 'analogue' ILI datasets along with the specific design details (diameter, wall thickness, grade, operating pressure) of the Northern Gateway pipeline. Under such an approach it is important to ensure that the analogue datasets are representative (or slightly conservative) relative to the expected internal corrosion performance of the Northern Gateway pipeline. In this way, the reliability parameters of internal corrosion feature incident rate, internal corrosion feature size distribution, and internal corrosion growth rate that are obtained from the analogue ILI datasets can be employed, knowing that the critical reliability data that they impart are representative, or conservative. To ensure that this is the case, the following measures should be adopted.

Table 6
Internal Corrosion Measures

Threat Factor	Area of Concern	Controls	Action
Water Content	Elevated water content can result in stratification in some flow regimes, and may result in enhanced corrosivity	Control BS&W Northern Gateway pipeline to 0.5% max.	Reflects current tariff specification. Safeguards to be addressed by strict enforcement of tariffs and controls
		Maintain turbulent flow to entrain what little water that exists in the product stream flow	Reflects current design. Design of operating safeguards to be addressed during development of operating procedures.
	Ensure that water content in pipeline from which analogue ILI dataset is obtained is representative of water content expected in Northern Gateway pipeline.	Ensure that the analogue ILI dataset is representative of BS&W contents of 0.5% max.	To be addressed during selection of analogue ILI database
Deposit of Solids	Solid deposition can result in under-deposit corrosion	Ensure that design product stream velocities exceed threshold for solid deposition.	Reflects current design. Design of operating safeguards to be addressed during development of operating procedures.
	Accumulation of solids could occur in dead legs, leading to under-deposit corrosion at those locations	Ensure that dead legs are eliminated in the final design.	To be addressed by Northern Gateway detailed design.
Microbial Corrosion	Operating temperature is favourable to increase in MIC activity for both the dilbit pipeline.	During the operation, monitor flow conditions for MIC susceptibility, and use biocides, if necessary	To be addressed by Northern Gateway detailed design, and in operating procedures.



5.3. Stress Corrosion Cracking

5.3.1 Threat Potential

Based on industry experience, susceptibility to SCC has been associated with coatings other than the following:

- Fusion bond epoxy (FBE);
- Urethane and liquid epoxy;
- Extruded polyethylene;
- Multi-layer or composite coatings

The threat potential for SCC is anticipated to be negligible (i.e., this threat will not contribute in a significant way to overall risk), provided that the coating systems used on the Northern Gateway pipeline are limited to those listed above. This will need to be addressed by Northern Gateway purchase specifications and detailed design.



5.4. Manufacturing Defects

5.4.1 Threat Potential

Enbridge's pipe procurement program specifies rigorous controls to ensure the quality of line pipe to be supplied to the Northern Gateway project. Apart from pipe purchase specifications that exceed the requirements of CSA 245.1 and API 5LX, these controls include supplier pre-qualification practices that focus on technical and quality criteria, as well as 100% 3rd party pipe mill quality surveillance that conforms to a Test Plan that is defined during the material requisition process, and which mirrors the manufacturer's Inspection and Test Plan. No improvements are recommended to these controls, and given the presence of the controls, the threat of manufacturing defects is not anticipated to be a significant contributor to overall risk for the Northern Gateway pipeline.

5.4.1 Approach

The threat of manufacturing defects does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Despite the fact that this threat is not anticipated to contribute significantly to overall risk, an attempt will be made to achieve an upper-bound estimate of failure frequency based on operating experience of recent installations of pipeline that use rigorous line pipe quality procedures during the procurement process.



5.5. Construction Defects

5.5.1 Threat Potential

Enbridge's construction practices that will be used in the construction of the Northern Gateway pipeline specify rigorous controls to ensure the quality of the pipeline installation, including welding processes. In addition, rigorous quality checks will be employed, including 100% NDT using phased array ultrasonics and/or X-ray inspection, as well as 100% inspection with a pipe size and deformation tool after installation to ensure that the pipeline is free of dents, buckles, and excessive out-of-round conditions. Tight controls imposed on line pipe carbon equivalent as well as the use of a mechanized low hydrogen welding process in which procedural variables are tightly controlled precludes the likelihood of weld cracking, or other systemic welding-related defects.

No improvements are recommended to these controls, and given the presence of the controls, the threat of construction defects is not anticipated to be a significant contributor to overall risk for the Northern Gateway pipeline.

5.5.2 Approach

The threat of construction defects does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Despite the fact that this threat is not anticipated to contribute significantly to overall risk, an attempt will be made to achieve an upper-bound estimate of failure frequency based on operating experience of recent installations of pipeline that use rigorous pipeline installation and inspection practices.



5.6. Equipment Failure

5.6.1 Threat Potential

It is expected that the pipeline will have some degree of exposure to the threat of equipment failure. Nevertheless, Enbridge's existing mechanical integrity program is highly-evolved and effective, as evidenced by the results of the Mechanical Integrity Questionnaire, which returned an evaluation score of 89 out of a possible 92 points. The three missing points were all related to physical configuration of the proposed pipeline (i.e., remotely monitored and controlled pipelines, at least one of which will operate in a batched mode of operation), and therefore there are no recommendations for improvement of the mechanical integrity program. Therefore, the failure frequency attributed to this threat is expected to be at the lower-bound end of operating experience.

5.6.2 Approach

The threat of equipment failure does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Due to the well-developed nature of the mechanical integrity program that will be implemented for the Northern Gateway pipelines, this threat is expected to manifest itself at the lower-bound end of operating experience. Reflecting this fact, an attempt will be made to achieve an estimate of failure frequency based on operating experience of recent installations of pipeline that employ similar mechanical integrity programs and practices.



5.7. Third Party Damage

5.7.1 Threat Potential

All pipelines experience some level of threat due to third party damage, the magnitude of this threat being a function of the effectiveness of damage prevention measures, adjacent land use, depth of cover, material properties and pipeline design. Although damage prevention measures can help to offset this threat, third party damage can never be fully neutralized, and so this is expected to be one of the primary threats in contributing to overall pipeline risk.

5.7.2 Approach

A reliability model exists that considers all the parameters of damage prevention measures, adjacent land use, depth of cover, material properties and pipeline design, and it this model will be used here (see Reference 2). The reliability approach employs a fault tree model to estimate hit frequency, and a separate stochastic model to predict probability of failure, given a hit. In order to address the primarily remote nature of the right-of-way, an attempt will be made to calibrate the fault tree model with actual incident data that is derived from operating experience in remote areas.

5.8. Incorrect Operations

5.8.1 Threat Potential

All pipelines experience some level of threat due to incorrect operations, the magnitude of this threat being a function of the effectiveness of design-related and operations/maintenance related practices and measures. Although design, operations and maintenance practices can help to offset this threat, incorrect operations can never be fully neutralized, and so this is expected to be one of the primary threats in contributing to overall pipeline risk.

5.8.2 Approach

The threat of incorrect operations does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Reflecting this fact, an attempt will be made to achieve an estimate of failure frequency based on operating incident data, related to this threat, modified by the results of the Operations Questionnaire that was administered during the Threat Assessment Workshop (See Table 4).

While detailed design, operating and maintenance procedures have not been completed at this stage, an evaluation of the operating procedures that was completed during the Threat Assessment Workshop identified potential areas for further improvement. These measures include the following:

- Consideration of installation of VFDs with pressure control valves at each station
- Improve the consistency with which physical changes, changes in operating conditions, and changes in operating procedures invoke the MOC procedure in LP Operations
- Improve the consistency with which 'temporary changes' invoke the MOC procedure in LP Operations
- Improve the consistency with which cross-functional operating procedure changes are reviewed between different operational stakeholders as part of the MOC process
- Improve the consistency with which maintenance programs and inspection schedules are updated as part of the MOC process
- Improve the consistency with which drawings, statement of operating limits, and any other safety information is modified as part of the MOC process
- Improve the consistency with which operations and maintenance employees who work in the area of change are notified and trained (if necessary) as part of the MOC process
- Improve the consistency with which the effect of a proposed change is reviewed on all separate but interrelated procedures as part of the MOC process
- Implement a MOC process whereby changes in operating procedures are reviewed with respect to equipment and materials impacts to determine whether they will cause any increased rate of deterioration or failure due to changes in failure mechanisms
- Consider the implementation of random drug testing



- Include pipeline materials stresses in the operator training curriculum so that they can be aware of the impacts of any changes in operating conditions on pipeline integrity

5.9. Geotechnical / Hydrological Forces

5.9.1 Threat Potential

The Northern Gateway pipeline transects several mountain ranges en route from Burderheim, AB to Kitimat, BC. These mountain ranges harbour potential for a wide range of geotechnical and hydrological conditions, and so while mitigation measures will be implemented to avoid or manage these conditions, it is unavoidable that the pipeline will experience some level of threat due to outside forces. Therefore, this is expected to be one of the primary threats in contributing to overall pipeline risk.

5.9.2 Approach

In order to assess the degree of threat that a pipeline will be exposed to, a thorough evaluation of all information along the length of the pipeline is currently being completed. To ensure completeness, this review must include published information such as soils maps, topographic maps, hydrological maps, pipeline alignment sheets, incident reports related to ground movement, hydrological events, and floods, studies, texts, and engineering reports. From this initial data gathering and review, potential hazard sites should be identified, which must prompt site visits to collect and analyze site-specific information, such as evidence of ground movement, such as slumping, cracks in soil, tilted trees, trees with diverted growth orientation, rock fall, flood marks, scour marks, etc. Where necessary, long-term monitoring, using instrumentation such as slope inclinometers should be considered.

Only once the above information is collected and analyzed can the extent of outside force threat, including the potential magnitude of movement, and estimates of movement frequency be established.

The above information gathering and mitigation plan is currently ongoing, and at this point it is premature to identify specific sites, mitigation plans, and estimates of outside force frequency and magnitude. This information will be made available in time for the quantitative failure likelihood assessment, and the mitigation plans will be incorporated into the detailed design.



5.10. Other Threats

5.10.1 Threat Potential

As highlighted in Section 4.10, Other Threats that were identified on the Northern Gateway pipeline include:

- Concomitant Failure;
- External Loading at Aerial Crossings;, and,
- Forest Fires

All the above threats can be effectively managed such that they can be considered to be negligible, relative to the other primary threat contributors. A summary of the controls that must be implemented in order to achieve the goal of full management of the conditions is provided below.

Table 7
Other Measures

Threat Factor	Area of Concern	Controls	Action
External Loading at Aerial Crossing Locations	Potential wind and / or snow loading at aerial crossing locations	Considerations for external loading, such as wind loading must be addressed.	To be addressed during detailed design.
Forest Fires	Potential for forest fires to affect pipeline operations.	Not considered to be a significant threat on RoW with buried pipeline in a cleared right-of-way. Ensure creation of adequate fire break at above-ground installations, such as at valve sites and aerial crossings.	To be addressed during detailed design and construction.



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ENBRIDGE NORTHERN GATEWAY PROJECT

Semi-Quantitative Risk Assessment

**SUBMITTED IN RESPONSE TO JOINT REVIEW PANEL INFORMATION REQUEST NUMBER
8.1(B)**

Attachment 2: Failure Likelihood Assessment

Northern Gateway Pipeline



Risk Assessment Support Document Failure Likelihood Assessment

April 30, 2012

Prepared by:



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1. Introduction

The Enbridge Northern Gateway oil pipeline will transport diluted bitumen ('dilbit') approximately 1172 km from Bruderheim, Alberta (near Edmonton), to a new marine terminal in Kitimat, British Columbia.

A risk-based design process is being undertaken for this pipeline. Risk-based design is a process that enables the pipeline design team to minimize risk in a cost-effective manner and to demonstrate safe operations.

In support of the risk-based design process, a Threat Assessment was completed to identify significant threats that could lead to loss-of-containment failures on the Northern Gateway dilbit pipeline. A report on the Threat Assessment was submitted to Worley Parsons on December 23, 2011,¹ and it identified eight threats to be addressed as part of the failure likelihood assessment:

- Internal Corrosion;
- External Corrosion;
- 3rd Party Damage;
- Geotechnical / Hydrological Forces;
- Manufacturing Defects;
- Construction Defects;
- Equipment Failure; and,
- Incorrect Operations

In support of a risk assessment, a quantitative failure frequency analysis was performed. The results of that quantitative failure frequency analysis is provided in a separate electronic file, presented in tabular form, and indexed by pipeline stationing. This report outlines the approach taken to derive those estimates of failure frequency.

¹ "Northern Gateway Pipeline Threat Assessment", Confidential Report submitted by Dynamic Risk, Ltd. to Worley Parsons, Ltd., December 23, 2011.



2. Approach

One of the challenges of quantitative risk assessments on a new pipeline is that industry failure statistics are not directly applicable to modern pipeline designs, materials, and operating (i.e., assessment) practices. A review of industry failure statistics indicates that the vast majority of pipeline failures occur on pipelines installed in the 1970s or earlier^{2 3}, which is a significant portion of all pipelines in operation today. These pipelines were largely developed prior to the advent of several risk-critical technologies, such as:

- Continuous casting of steel slabs;
- Thermomechanical Controlled Processing (TMCP) technology for skelp production;
- High Strength Low Alloy (HSLA) steel design;
- Low sulphur steels;
- Inclusion shape control;
- High toughness steels;
- Implementation of quality systems and the use of highly constrained process control variables during pipe manufacture;
- Highly-constrained mechanized welding processes using low-hydrogen welding processes;
- Phased array ultrasonic inspection and 100% non-destructive inspection;
- High performance coating systems such as fusion bonded epoxy coatings;
- Design-phase identification and avoidance of geotechnical hazards through consideration of geotechnical input during routing studies;
- Design-phase identification of internal corrosion threat factors and design of mitigation plans through internal corrosion modeling;
- Identification of HVAC interference effects and development of mitigation plans through diagnostic testing of cathodic protection systems;
- Implementation of Quality Management Systems during design, construction and operations;
- Improved ROW surveillance; and
- Advances in automatic control (SCADA)

With the continued advancement of these and other technologies, historical incident data is not a sound foundation for estimating failure frequency in modern pipelines.

² Kiefner, J.F., Trench, C.J., "Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction" API Publication, December, 2001.

³ U.S. Department of Transportation Pipeline & Hazardous Materials Safety Administration Pipeline Safety Stakeholder Communications, Significant Incident Data, 1986-2001.

Another disadvantage of using industry failure databases as the basis of a quantitative risk assessment is that it is not possible to focus on site-specific threats and highlight discrete areas of heightened threat, such as would be the case where geotechnical hazards exist.

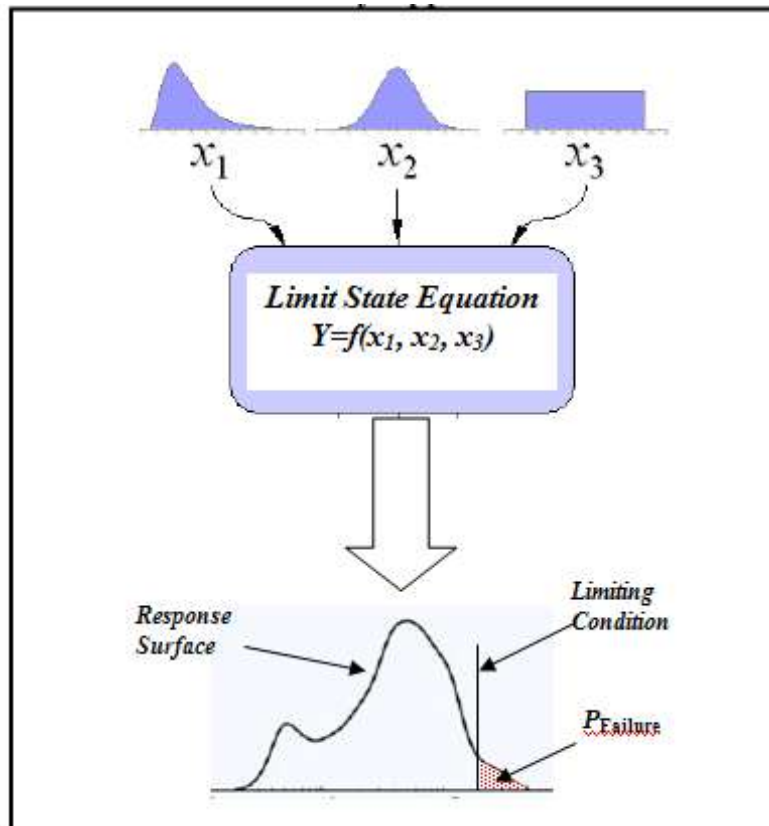
Finally, because the designs of older pipelines were generally not optimized using modern modelling techniques such as overland spill modeling and valve optimization, the consequences of failure in older pipelines, as reported in industry incident databases are often more severe than would be the case in a pipeline that was designed using a modern risk-based design approach.

Reliability methods have been widely adopted in the nuclear and aerospace industry, to identify and manage threats. In recent years, the pipeline industry has moved towards adopting this as a tool for managing risk and reliability, and pipeline industry research organizations such as PRCI and EPRG have funded research to develop reliability-based models for various threats for pipeline systems. Reliability models employ limit state functions for the specific damage mechanism of interest in which the load variables and resistance variables are characterized in terms of probability density functions. As a result, reliability modeling techniques such as Monte Carlo Analysis can be used to characterize the probability of failure on a pipeline. Reliability methods provide a powerful tool to make accurate, quantitative predictions on likelihood of failure and expected lifespan.

In the pipeline industry, reliability models exist for the most significant threats, including 3rd Party Damage, Internal Corrosion and External Corrosion. In addition, geotechnical threats can be characterized in terms of expected magnitude and associated frequency of occurrence, thereby enabling pipeline reliability to be established at each geotechnically-active site. The basis of every reliability model is a limit state equation that describes the failure conditions for each mechanism. Furthermore, at least one of the input variables to this limit state equation must be characterized as a probability density function, as illustrated in Figure 1. Therefore, a reliability approach is not possible for some threats, such as incorrect operations, where these probability density functions are not available. For these threats (which fortunately usually constitute 2nd-order threats, in terms of failure likelihood magnitude), the only alternative is to employ industry failure statistics, incorporating some measure of compensation (where appropriate) to account for differences in materials, design and operations that are characteristic of modern pipelines.

At the time of writing, an INGAA / NYSearch / GTI Initiative is currently under way to review industry failure incident data and to quantify the contribution of combined threat failures. While this work is not yet complete, what can be said for the time-being, is that regardless of what factors contributed to failure in any given incident, in practice, the failure incident is recorded and assigned to one of the major threat categories in the failure database. Therefore, provided industry failure incident data are used to benchmark estimated values of failure frequency, the contribution of threat interaction is intrinsically addressed in the estimates.

Figure 1
Reliability Approach



The following Sections outline the approach used to derive estimates of failure likelihood for each of the eight significant threats that were identified during the Threat Assessment.

2.1. External Corrosion

The reliability approach for external corrosion employs the imposition of an analogue ILI dataset upon the design and materials for the Northern Gateway pipeline. In this respect, the reliability analysis using analogue ILI data essentially models how the pipeline materials and design for the Northern Gateway pipeline responds to an anticipated degradation process and establishes how quickly the reliability degrades to a point where failure likelihood becomes significant. For this reason, it is essential that the analogue ILI dataset is representative of the degradation process, including defect incidence rate, defect size distribution, and defect growth rate distribution.

2.1.1 Selection of Analogue ILI Data

After a review of candidate ILI datasets, the external wall loss feature list of interacted features (6t x 6t interaction rule) from the 2010 in-line inspection of Enbridge's Line 4

(BU-QU) was chosen. Several factors were considered in selecting that inspection dataset to ensure that it could be established as being representative of corrosion management performance anticipated for the Northern Gateway pipeline. Among these factors was the quality of the ILI dataset. Tool quality factors such as detection reliability and sizing accuracy were reviewed to ensure that they represent the current state of the art in tool performance. A summary of the tool performance standards for the 2010 in-line inspection of Line 4 is provided in Table 1.

Table 1
Detection, Sizing and Location Accuracy for Candidate ILI Dataset

	METAL LOSS CATEGORY		
	PITTING <(3t X 3t)*	GENERAL >(3t x 3t)*	GOUGING
Minimum Depth for Accurate Sizing	If surface dimension is > 0.275" x 0.275" or 0.4t x 0.4t (whichever greater): 0.2t	0.1t	If width > 0.5t or 0.275" (whichever greater): 0.2t If width > 3t: 0.1t
Sizing Accuracy (Depth)	±0.1t	±0.1t	±0.1t
Sizing Accuracy (Length)	±0.4"	±0.8"	±0.8"
Sizing Accuracy (Width)	±0.8"	±0.8"	±0.8"
Location Accuracy (Axial)	±8" between the feature and the reference girth weld and ±1% of stated distance between reference girth weld and identified location reference		
Location Accuracy (Circumferential)	±7.5 degrees which for ease of reference is stated to the nearest half hour clock position		

In order to remove over-conservatism in the analysis, it is best to review candidate ILI datasets to identify and remove wall loss data that is not attributed to active corrosion, since otherwise, the presence of wall loss that is associated with benign features, such as manufacturing imperfections results in a over-estimation of active corrosion feature density. Furthermore, non-zero wall loss rates are inferred from the presence of such benign features, and those wall loss rates will be assigned to what are in fact static features. One effective method that can be used to screen for active wall loss is to use data derived from pit-matching of separate in-line inspections. Because pit-matched data was not available, a conservative approach to determining corrosion growth rate was used, which is described in the following Section.

Beyond the quality of ILI data, several other factors were considered in selecting the Line 4 dataset, including the following:

- coating type (FBE in both Line 4 and in the proposed new Northern Gateway Pipeline)
- Coating specification (i.e., the same Enbridge coating specification will apply to both Line 4 and the proposed new Northern Gateway pipeline),



- Operating environment (Western Plains are common to a portion of the proposed new Northern Gateway pipeline), and
- Cathodic protection and other operating standards (i.e., the same Enbridge standards apply to both Line 4 and the proposed new Northern Gateway pipeline)

2.1.2 Reliability Approach

The above section described screening considerations for selecting the appropriate analogue ILI dataset so that it can be considered as representative of the corrosion mechanism and severity that is expected on the Northern Gateway pipeline. Having chosen an analogue ILI dataset, it was incorporated into the reliability analysis procedure described in this section in order to establish estimates of pipeline reliability and failure likelihood as a function of year of operation.

A Monte Carlo approach was developed to assimilate distributions derived from size and growth rate distributions derived from the analogue ILI dataset, and to apply those distributions against the modified ASME B31G failure limit state criterion, which, for the purposes of the analysis, was rearranged to determine depth at failure:

$$d_f = \text{MIN} \left[(0.8t), \left(\frac{t(\sigma_{op} - \bar{\sigma})}{0.85 \left(\frac{\sigma_{op}}{M} - \bar{\sigma} \right)} \right) \right]$$

Equation 1

Where,

d_f = depth at failure;

t = Wall thickness;

σ_{op} = Operating Stress;

$\bar{\sigma}$ = Flow stress;

$$M = \sqrt{1 + 0.6257 \frac{L^2}{Dt} - 0.003375 \left(\frac{L}{Dt} \right)^2}$$

(for $L \leq \sqrt{50Dt}$)

$$M = 3.3 + 0.032 \frac{L^2}{Dt}$$

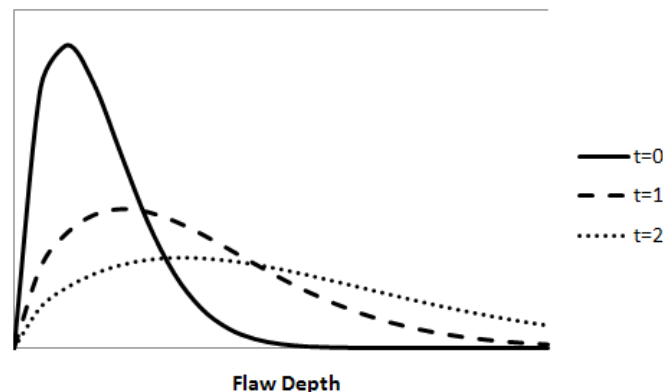
(for $L > \sqrt{50Dt}$)

L = Defect length

In the Monte Carlo analysis, the variables of pipe diameter, wall thickness, yield strength, and operating pressure that is specific to the Northern Gateway pipeline design were used to create dynamic segments, and a separate reliability analysis was completed for each dynamic segment. Corrosion feature incidence rates, and the distribution parameters for corrosion feature length and depth are determined from the analogue ILI data, as were corrosion feature growth rates.

When using ILI data for the purposes of establishing these parameters, it is important to recognize that the quantities derived represent values at a particular point in time (i.e., the date of last inspection). Furthermore, these quantities are subject to tool measurement error. Corrosion feature depth is therefore considered characteristic of the depth after some period of time. When applied to a new pipeline, the depth distribution must be adjusted downwards (accounting for some assumed corrosion growth rate) when the modeled pipeline age is smaller than that from which the analogue ILI data was obtained. Similarly, the depth distribution must be adjusted upwards when the modeled pipeline age is larger than that from which the analogue ILI data was obtained. This is illustrated in Figure 2, which shows how the flaw distribution flattens and translates with time, t . Specifically, as can be seen in this Figure, as time increases, the mean of the flaw depth distribution increases, and that the standard deviation of the flaw depth distribution also increases.

Figure 2
Illustration of How Flaw Depth Distribution Changes With Time



In the absence of any other information pertaining to how growth rate varies with time, a linear growth rate assumption can generally be considered a reasonable, yet conservative approximation, since it ignores the polarizing effects of the accumulation of corrosion product.

The high-performance coating systems that are characteristic of modern pipelines, such as fusion bonded epoxy are not susceptible to time-dependent coating degradation to the extent that older vintage coating systems are. Therefore, it was considered realistic



to assume that any coating damage that is inferred from the presence of a corrosion feature was created at the time of installation, and that the areal extent of coating damage, and hence the potential for increases in wall loss area (i.e., length and width) does not change appreciably with time.

In the Monte Carlo simulation, corrosion feature depth, as a function of time, and feature length are sampled stochastically, based on the probability density functions for those parameters derived from the analogue ILI dataset. A further stochastic adjustment on flaw depth is made to account for the tool error associated with the ILI tool from which the analogue data was derived. Because correlations derived from <Tool-Predicted> to <In-Ditch Measurement> data pairs were not available for the analogue dataset, a standard tool measurement error of $\pm 10\%$ w.t., 80% of the time was used. In statistical terms, this corresponds to a normal error distribution having a mean of 0, and a standard deviation of 7.8% of the wall thickness.

Assuming a linear growth model, the stochastically-sampled flaw depth estimate was adjusted to account for the difference between the age of the analogue pipeline at the time that the ILI data was acquired, and the modeled age of the new pipeline:

$$d_A^o = \frac{d^o \cdot T_A}{T_{ILI}}$$

Equation 2

Where,

d_A^o = Stochastically sampled flaw depth at the specific time assumed in the analysis;

d^o = Stochastically sampled flaw depth, derived from the analogue ILI dataset (incorporating stochastic adjustment for analogue ILI tool error)

T_A = Year of operation for the Northern Gateway pipeline that is being assumed in the analysis

T_{ILI} = Year of operation for the analogue pipeline when the ILI assessment was completed.

For the purposes of the Monte Carlo simulation, all pipe parameters that are contained in the limit state function shown in Equation 1 (i.e., pipe wall thickness, operating stress level, and flow stress) correspond to the Northern Gateway pipeline for which failure probability values were being sought.

Failure is predicted when the stochastically sampled flaw depth derived from Equation 2 exceeds the flaw depth that defines the limiting condition (derived from Equation 1). When the Monte Carlo simulation is performed through multiple iterations, the probability of failure for the given year of analysis is defined as the proportion of those iterations that return a failure prediction. This probability is defined as the probability of failure, given the presence of a corrosion feature, $P_{i,F}$. The overall probability of failure for a given dynamic segment of the new pipeline in the year of operation being considered in the analysis is defined as:



$$P_{f,DS} = \rho_{ILI} \cdot \frac{D_N}{D_{ILI}} \cdot L_{DS} \cdot P_{f,F}$$

Equation 3

- $P_{f,DS}$ = Probability of failure for the dynamic segment
- ρ_{ILI} = Corrosion feature density per unit length of pipeline derived from the analogue ILI dataset
- D_N = Diameter of the new pipeline
- D_{ILI} = Diameter of the pipeline from which the analogue ILI data was derived
- L_{DS} = Length of the dynamic segment in the new pipeline
- $P_{f,F}$ = Probability of failure, given the presence of a corrosion feature

By performing a separate analysis for each year of operation, and for each dynamic segment, a failure likelihood profile was generated for each year of operation of the Northern Gateway pipeline out to 20 years after installation. It is important to note that in the analysis, each corrosion feature is allowed to grow in an unmitigated fashion throughout the full time period covered for the analysis. This represents a significantly conservative assumption, as in reality, several measures will be employed to mitigate corrosion, including:

- Regular cathodic protection surveys will be conducted, and any lows will be immediately remediated;
- In-line inspections will be completed on a regular basis, and any features that exceed the acceptance criteria established in CSA Z662-11 will be excavated, examined, and repaired or re-coated.
- In practice, even when left unmitigated, corrosion growth rates tend to decline with the passage of time due to the accumulation of corrosion products. This natural tendency for decreasing corrosion growth rates with time has been disregarded in the analysis.

It was determined that the failure likelihood varied by wall thickness and pressure, however the failure probability for all segments was essentially zero for at least the first 11 years of operation. After that, failure likelihood increased to measurable values, starting with the lighter wall thickness pipelines operating at maximum operating pressure. For the heaviest wall thicknesses of 18.3 mm and 19.8 mm, failure likelihood didn't reach measurable levels even after 20 years' service.



2.1.3 Determination of Leak and Rupture

In order to support a risk analysis, the output from the failure likelihood analysis must be relevant to the consequence analysis. Therefore, the results of a failure likelihood analysis must specify more than frequency of occurrence; instead, the frequencies of occurrence must be tied to an outcome, with outcome being related to magnitude of release, and hence hole-size. In the reliability analysis described in the preceding Section, the proportion of ruptures are derived by first calculating the critical through-wall flaw size as a function of material properties and operating parameters of the Northern Gateway pipeline. The NG-18 flaw equation was used determining the critical through-wall flaw size⁴:

$$K_c^2 = \frac{12 \cdot C_v \cdot E}{A_c} = \frac{8 \cdot c \cdot \sigma^2}{\pi} \ln \sec \left[\frac{\pi \cdot M_r \cdot \sigma_h}{2 \cdot \sigma} \right]$$

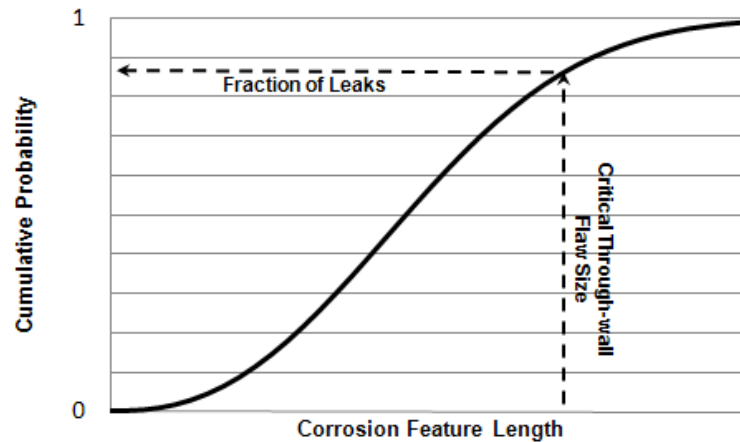
Equation 4

The above relationship is commonly used to determine the maximum size defect that will leak rather than rupture. At high toughness values, it represents a flow-stress or plastic instability criterion (typical of the failure mode of most corrosion features), whereas at lower toughness values, it may represent a conservative representation of the leak/rupture boundary for corrosion features.

As is illustrated in Figure 3, the cumulative distribution function for flaw length, derived from the analogue ILI dataset was compared against the critical through-wall flaw length for the Northern Gateway pipeline. Using this approach, the proportion of features that have the potential to penetrate through-wall at a length greater than the critical through-wall flaw length can conservatively be said to have the potential to fail in rupture mode, while the remainder of the flaws will fail as leaks.

⁴ Eiber, R.J., and Leis, B.N., "Fracture Control Technology for Natural Gas Pipelines Circa 2001, PRCI Report No. PR-003-00108, July, 2001.

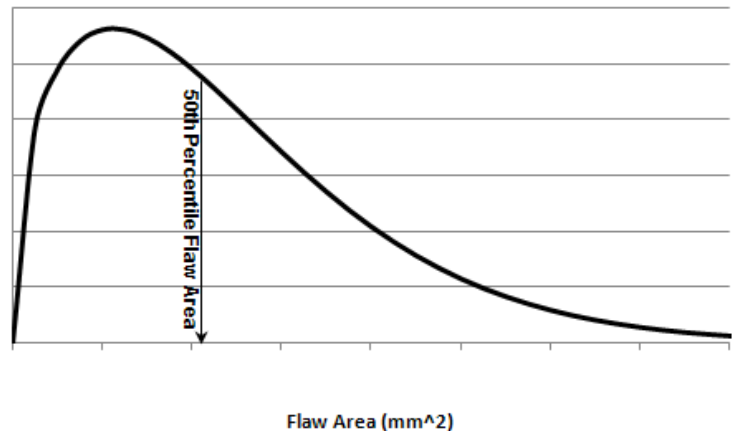
Figure 3
Determination of Fraction of Leaks and Ruptures from Corrosion Feature Length CDF and Critical Through-wall Flaw Size



Because critical through-wall flaw length is a function of wall thickness and operating pressure, the proportion of leaks was determined for each dynamic segment, based on the feature length distribution obtained from the Line 4 ILI dataset.

The breakdown of leak sizes were obtained from the distribution of flaw areas (length x width) obtained from the Line 4 ILI dataset for those flaws that are predicted to fail by leak mode. A reasonable, yet conservative representation of the outcome associated with a leak was represented by the 50th percentile of flaw size area, as is depicted in Figure 4.

Figure 4
Determining Hole Area from Distribution of Flaw Area
for Leak-Designated Corrosion Features



For the Northern Gateway dilbit pipeline, the through-wall critical flaw size for leaks was determined in this way to be 45 mm.

2.2. Internal Corrosion

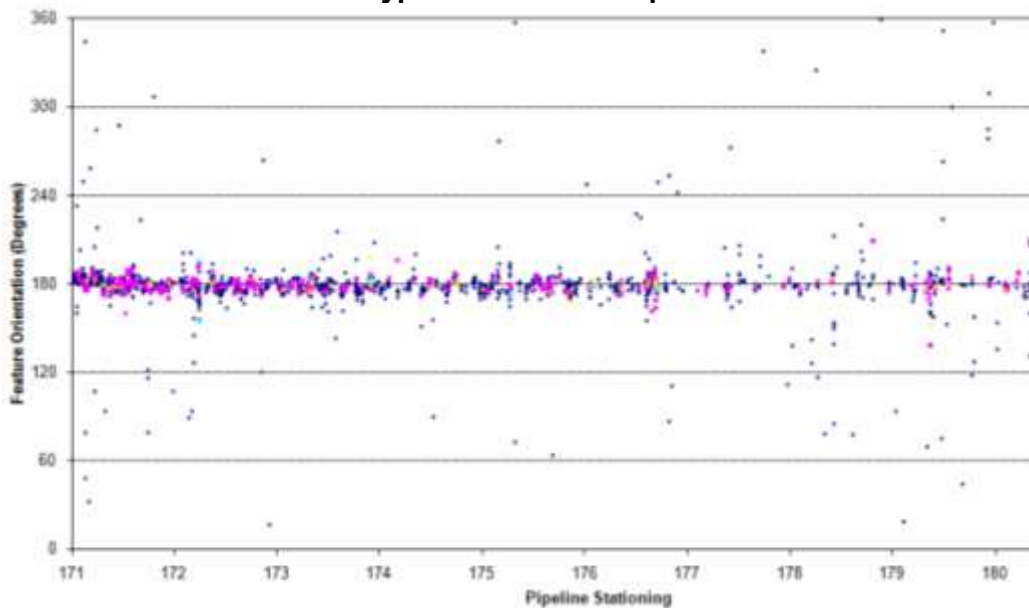
The reliability approach for internal corrosion is consistent with the approach described for external corrosion, although in the selection of candidate analogue ILI data, the considerations required to evaluate and compare the corrosion conditions between the proposed Northern Gateway pipeline and those of the candidate analogue datasets differ significantly over those employed for an assessment of external corrosion.

2.2.1 Selection of Analogue ILI Data

One of the simplest methods to perform screening for internal corrosion is to view orientation charts for internal wall loss features. Where water drop-out and accumulation is an essential aspect of the internal corrosion mechanism that is associated with the product and flow characteristics being considered (as is the case here), wall loss that is associated with internal corrosion should be expected at the bottom of the pipe, as illustrated in Figure 5. This is especially true where concentrations of internal wall loss can be seen to coincide with steeper pipeline inclination angles or receipt points.

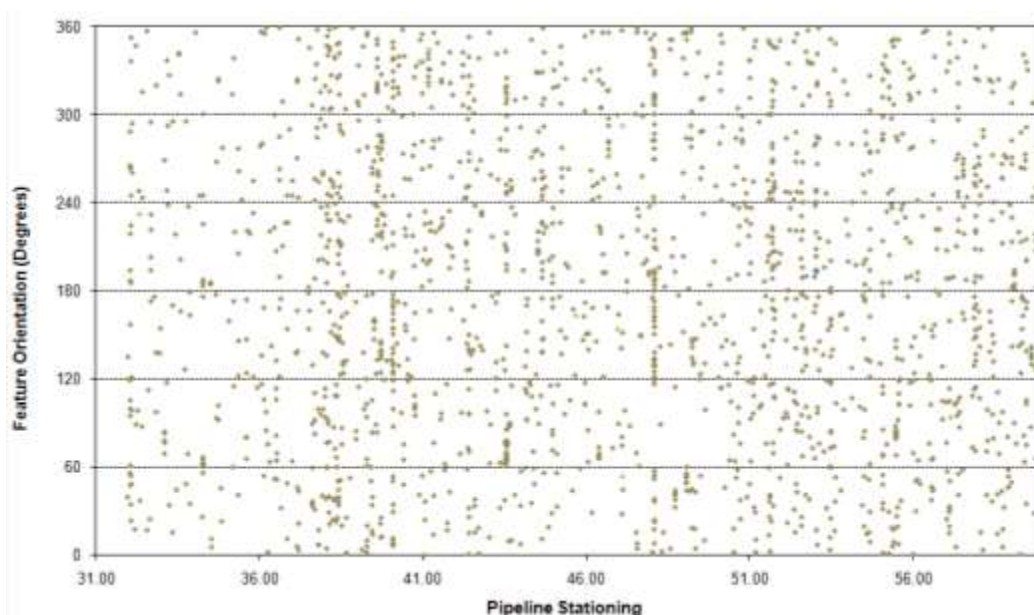


Figure 5
6 O'Clock Orientation Typical of Water Drop-out and Accumulation



On the other hand, a random distribution of internal wall loss features around the circumference of the pipe, with no apparent trends relative to inclination angle or receipt points might be more representative of benign manufacturing imperfections, as is represented in Figure 6.

Figure 6
Random Wall Loss Orientation Typical of Manufacturing Imperfections – No Apparent Active Internal Corrosion



Internal corrosion evaluation techniques are largely based on product stream characteristics and flow rates. For liquid products, the important parameters that should be included in a comparison of corrosivity are water content, erosion and erosion/corrosion, flow velocity, flow mechanism, temperature, susceptibility to under-deposit corrosion (solid deposition, MIC potential, and water chemistry), and mitigation measures (use of inhibition, biocides, or pigging). In order to ensure that the corrosion mechanism and corrosivity that is represented by the analogue ILI dataset is representative of that which would be expected in the Northern Gateway pipeline, an evaluation of all of these parameters were conducted. Through this process, it was determined that ILI data obtained from Enbridge's 36" Line 4 would be most representative of the corrosivity conditions expected on the Northern Gateway dilbit pipeline.

2.2.1.1 *Line 4 ILI Data (Analogue for Dilbit Pipeline)*

Approximately 10,000 km.yr worth of ILI data from the 36" Line 4 was reviewed, with no evidence of active internal corrosion. Discussions with Enbridge corrosion specialists confirmed that the 36" Line 4 is an excellent analogue for the Northern Gateway dilbit pipeline in respect of product stream composition and flow characteristics. With respect to the latter issue, both pipelines will operate in fully-turbulent mode, resulting in full entrainment of what little water is present (the maximum BS&W specification for the Northern Gateway dilbit pipeline is 0.5%). Therefore, because no water accumulation is expected, no significant internal corrosion is expected on this pipeline.

This conclusion is consistent with an API Publication "Pipeline Transportation of Diluted Bitumen from the Canadian Oil Sands"⁵, which states among its findings:

- Although oil sands diluted bitumen has been transported through Canadian and U.S. pipelines for more than a decade, there have been no instances of crude oil releases caused by internal corrosion from pipelines carrying Canadian diluted bitumen.
- Corrosivity of diluted bitumen is largely similar to crude oil, which is considered to be low. In addition, the threat of corrosion from diluted bitumen can be managed by conventional engineering practice in the same way as crude oil.

The above findings were also corroborated in a presentation given by Cheryl Trench to the 6th Annual Pipeline Safety Conference in November, 2011.⁶ The issue of crude oil sourced from Canadian oil sands was included in that presentation, and the results of an investigation into the internal corrosion history of pipelines carrying that product were provided. The study investigated PHMSA accident data for pipelines that have interconnections to Canadian crude sources. It also investigated data from the U.S. Energy Information Administration Form 814; shipment-by-shipment crude imports to determine which refineries were sourcing Canadian oilsands crude. Finally, it investigated pipeline industry information to determine all interconnections, including

⁵ <http://www.cepa.com/wp-content/uploads/2011/10/Facts-About-Pipeline-Transportation-of-Diluted-Bitumen.pdf>

⁶ Trench, C.J., "A Tour of Lessons Learned from PHMSA Accident Data", Pipeline Safety Trust 6th Annual Pipeline Safety Conference, New Orleans, LA, November 17, 2011.

storage hubs to determine which part of the pipeline infrastructure could have transported Canadian oilsands crude. The results of this analysis established that **there has not been one** failure in any of this infrastructure that is attributed to internal corrosion resulting from the transportation of Canadian oilsands crude.

In the absence of any evidence of active internal corrosion in any of the analogue ILI data, it was not possible to arrive at a finite value of expected failure likelihood for the Northern Gateway dilbit pipeline. An alternative strategy to obtain a finite (non-zero) estimate of internal corrosion failure likelihood for this pipeline might be to use Enbridge's operating Probability of Exceedence (POE) thresholds as an upper-bound (conservative) estimate.

2.3. 3rd Party Damage

The approach used for determining the reliability of a pipeline from the perspective of 3rd Party Damage was based on the approach developed by Chen and Nessim.⁷ In this approach, failure frequency can be established as the product of two independent variables; the frequency of incurring a hit by an excavator, and the probability of failure given such a hit:

$$FF_{3PD} = F_H \cdot P_{F,H}$$

Equation 5

Where,

FF_{3PD} = Failure Frequency due to 3rd Party Damage

F_H = Excavator Hit Frequency (hits/km.yr)

$P_{F,H}$ = Probability of Failure, Given a Hit

Chen and Nessim demonstrated that machines smaller than excavators do not significantly affect predicted failure probability.⁸ Based on this finding, only impacts by large machines such as excavators are addressed by this model.

⁷ Chen, Q., and Nessim, M., "Reliability-Based Prevention of Mechanical Damage", EPRG/PRCI Proceedings of the 12th Biennial Joint Technical Meeting on Pipeline Research, May, 1999, Paper 25.

⁸ Chen, Q. and Nessim, M.A., "Reliability-Based Prevention of Mechanical Damage to Pipelines", PRCI Project PR-244-9729, 1999.



2.3.1 Determination of Impact Frequency Due to 3rd Party Activity

The impact frequency due to 3rd party activity was determined by using a fault tree model developed by Chen and Nessim⁹. This fault tree model is summarized in Figure 7 and Figure 8.

⁹ *ibid.*

Figure 7
Impact Frequency Fault Tree

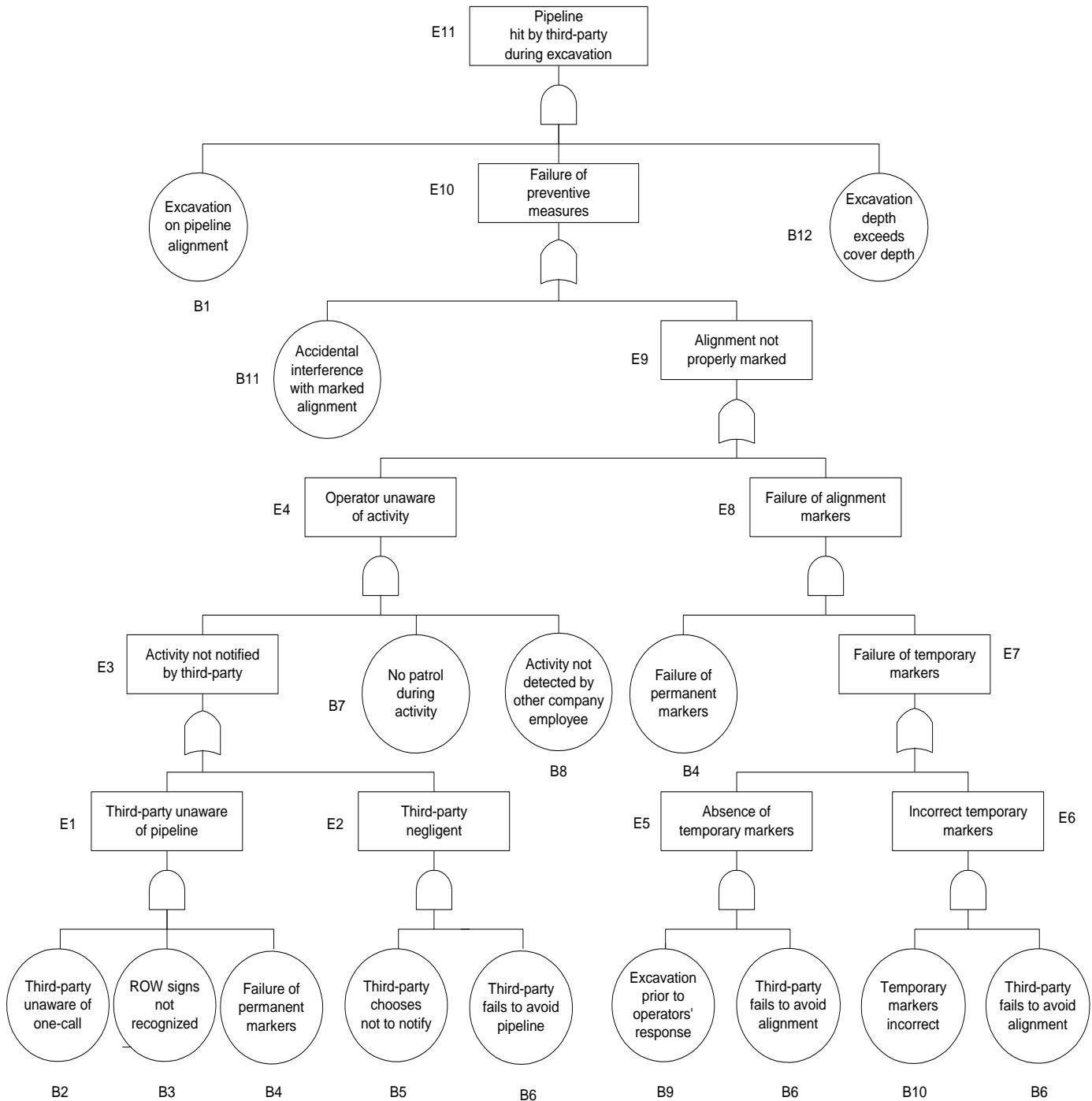


Figure 8
Probability Values for Fault Tree Modeling

No	Event	Conditions	Probability
B1	Excavation on pipeline alignment	Commercials/Industrial High density residential Low density residential Agricultural Remote	0.52/km-year 0.26/km-year 0.36/km-year 0.076/km-year 0.06/km-year
B2	Third-party unaware of one-call	Advertising via direct mail-outs and promotion among contractors A1+Community meetings Community meetings only	0.24 0.10 0.50
B3	Right-of-way signs not recognized	Signs at selected crossings Signs at all crossings All crossings plus intermittently along route	0.23 0.19 0.17
B4	Failure of permanent markers	No buried markers With buried markers	1.00 0.10
B5	Third-party chooses not to notify	Voluntary Mandatory Mandatory plus civil penalty Right-of-way agreement	0.58 0.33 0.14 0.11
B6	Third-party fails to avoid pipeline	N/A	0.40
B7	ROW patrols fail to detect activity	Semi-daily patrols Daily patrols Bi-daily patrols Weekly patrols Biweekly patrols Monthly patrols Semi-annual patrols Annual patrols	0.13 0.30 0.52 0.80 0.90 0.95 0.99 0.996
B8	Activity not detected by other employees	N/A	0.97
B9	Excavation prior to operator's response	Response at the same day Response within two days Response within three days	0.02 0.11 0.20
B10	Temporary mark incorrect	By company records By magnetic techniques By pipe locators/probe bars	0.20 0.09 0.01
B11	Accidental interference with marked alignment	Provide route information Locate/mark Locate/mark/site supervision Pipe exposed by hand	0.35 0.17 0.03 0.06
B12	Excavation depth exceeding cover depth	Cover depth = 0.8 m (2.5 ft) 0.9 m (3 ft) 1.2 m (4 ft) 1.5 m (5 ft) 1.8 m (6 ft)	0.42 0.25 0.08 0.07 0.06

The above fault tree model was used in conjunction with design, installation and operations data for the Northern Gateway pipeline that was supplied during the Threat Assessment Workshop, and which is summarized in Reference 1. Additionally, one-call notification time prior to response was determined to be 3 days¹⁰, and in Alberta it was determined to be 2 days.¹¹ Also, it was felt that the term “Remote”, with an expected frequency of excavation along the pipeline alignment of 0.06/km.yr did not realistically represent the very remote nature of much of the alignment through the mountainous areas of B.C. Therefore, a new designation of “Very Remote”, with a frequency of excavation along the pipeline alignment of 0.01/km.yr was added to address these areas.

2.3.2 Determination of Failure Probability, Given Excavator Impact

Given a failure in the measures to prevent the accidental contact of an excavator with the pipeline, a loss of containment may occur due to gouge-in-dent or puncture mechanisms, or alternatively a failure may not occur. The likelihood of having a gouge-in-dent or puncture failure given a contact with an excavator is a function of whether or not the pipeline resistance (a function of grade, wall thickness, and toughness) is greater or less than the driving forces for failure (a function of excavator force, bucket tooth dimensions, operating pressure). Where the resistance of the pipeline to failure exceeds the driving forces, no failure will occur. Otherwise, failure will occur.

Where failures occur that are related to external interference, the mode of failure is more likely to be gouge-in-dent than puncture.^{12,13} This is in part due to the fact that less force is required to cause a gouge-in-dent failure than is required to puncture a pipeline.

The model that determines the probability of failure, given a hit was derived on the basis of the work reported on in Reference 12, and utilizes a Monte Carlo analysis to assimilate the probability distributions of the various parameters employed. An overview of the approach is provided below.

2.3.2.1 *Test for Gouge-in-Dent*

Gouge-in-dent failure has been empirically described by the NG-18 Q-Factor Relationship:¹⁴

¹⁰ www.bconeccall.bc.ca

¹¹ www.alberta1call.com

¹² Fuglem, M.K., Chen, Q., and Stephens, M.J., “Pipeline Design for Mechanical Damage”, PRCI Report No. PR-244-9910, October, 2001.

¹³ Eiber, R.J., Leis, B.N., “Fracture Control Technology for Natural Gas Pipelines Circa 2001”, PRCI Report No. PR-003-00108, July, 2001, p. 57.

¹⁴ *ibid*, pp. 57-62



$$\sigma_h = \sigma_{fl} \left[\frac{(Q - C_2)^{0.6}}{C_3} \right]$$

Equation 6

Where,

σ_h = Hoop Stress at failure (ksi or MPa)

σ_{fl} = Flow Stress (ksi or MPa)

= Y.S. + 10 ksi or Y.S. + 68.9 MPa

C_2 = a constant

= 300 ft-lbs/in or 16 J/mm

C_3 = a constant

= 90 (ft-lbs/in)^{0.6} or 4.80 (J/mm)^{0.6}

$$Q = c_{v,2/3} \left[\frac{R t}{D d_g c_g} \right]$$

Equation 7

Where,

$C_{v,2/3}$ = 2/3 Upper-Shelf Charpy toughness (ft-lbs or J)

R = Pipe Radius (in or mm)

t = Wall Thickness (in or mm)

D = Maximum dent depth at the time of defect introduction (in or mm)

d_g = Depth of gouge (in or mm)

c_g = ½ gouge length (in or mm)

2.3.2.1.1. Input Parameters

The input parameters utilized in the analysis are described in this Section.

Flow Stress (σ_{fl})

As defined above, flow stress is a function of yield strength. Yield strength distribution parameters were obtained from Reference 12, which indicates that yield strength is normally distributed, with distribution parameters as follows:

μ = 1.1(SMYS)

COV = 0.035(SMYS)

Charpy Toughness (c_v)

The toughness for the Northern Gateway pipelines was conservatively estimated at 27J, full-size. This is considered quite conservative, since modern pipeline materials easily exceed this value.

Pipe Radius (R)

Pipe radius is a function of pipe diameter (D). Pipe diameter distribution parameters were obtained from Reference 12, which indicates that pipe diameter is normally distributed, with distribution parameters as follows:

$$\begin{aligned}\mu &= 1.0(\text{Nominal Diameter}) \\ \text{COV} &= 0.0006(\text{Nominal Diameter})\end{aligned}$$

Wall Thickness (t)

Wall thickness distribution parameters were obtained from Reference 12, which indicates that wall thickness is normally distributed, with distribution parameters as follows:

$$\begin{aligned}\mu &= 1.0(\text{Nominal Wall Thickness}) \\ \text{COV} &= 0.01(\text{Nominal Wall Thickness})\end{aligned}$$

Ultimate Tensile Strength (UTS)

Ultimate tensile strength distribution parameters were obtained from Reference 12, which indicates that ultimate tensile strength is normally distributed, with average and standard deviation values on Grade 483 pipe of 639.2 MPa and 22.4 MPa, respectively.

Excavator Force (F_d)

Maximum Excavator Force Capacity (F_d , kN) has been shown to be a function of excavator mass (m_{ex} , tonnes):¹⁵

$$F_d = 14.2 \cdot m_{ex}^{0.928}$$

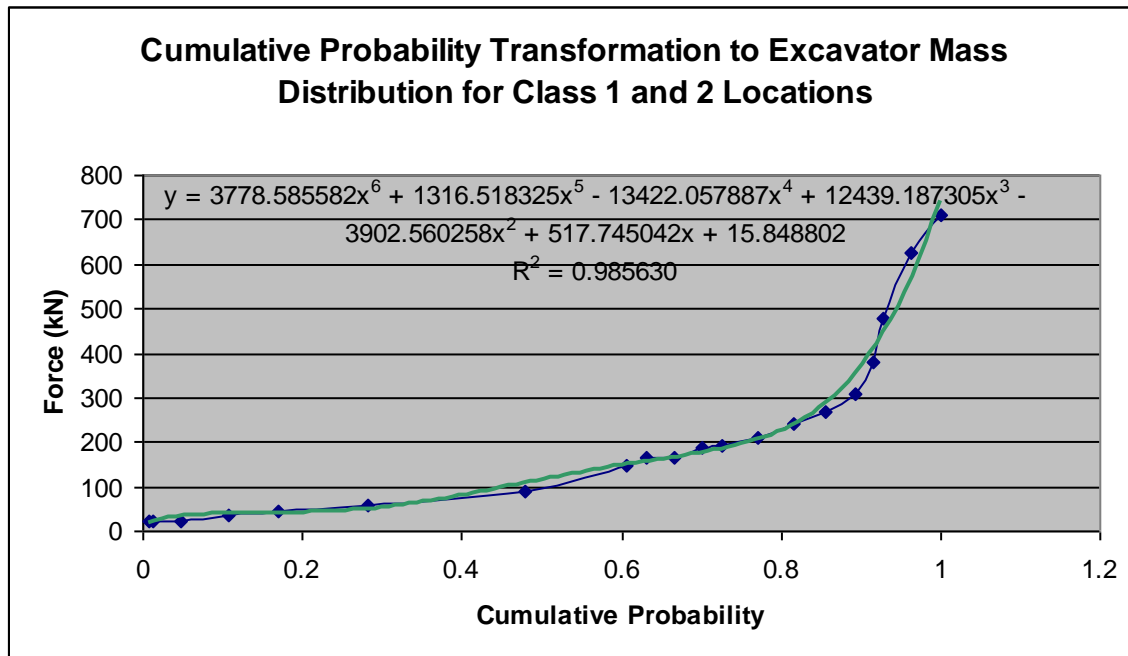
Equation 8

Driver and Zimmerman presented a distribution of excavators by machine mass.¹⁶ This is the same excavator mass distribution that was employed in Reference 12. As outlined

¹⁵ Roovers et al, "EPRG Methods for Assessing the Tolerance and Resistance of Pipelines to External Damage", Proceedings of Joint EPRG/PRCI Conference on Pipeline Technology, Vol. II, 2000, p 419.

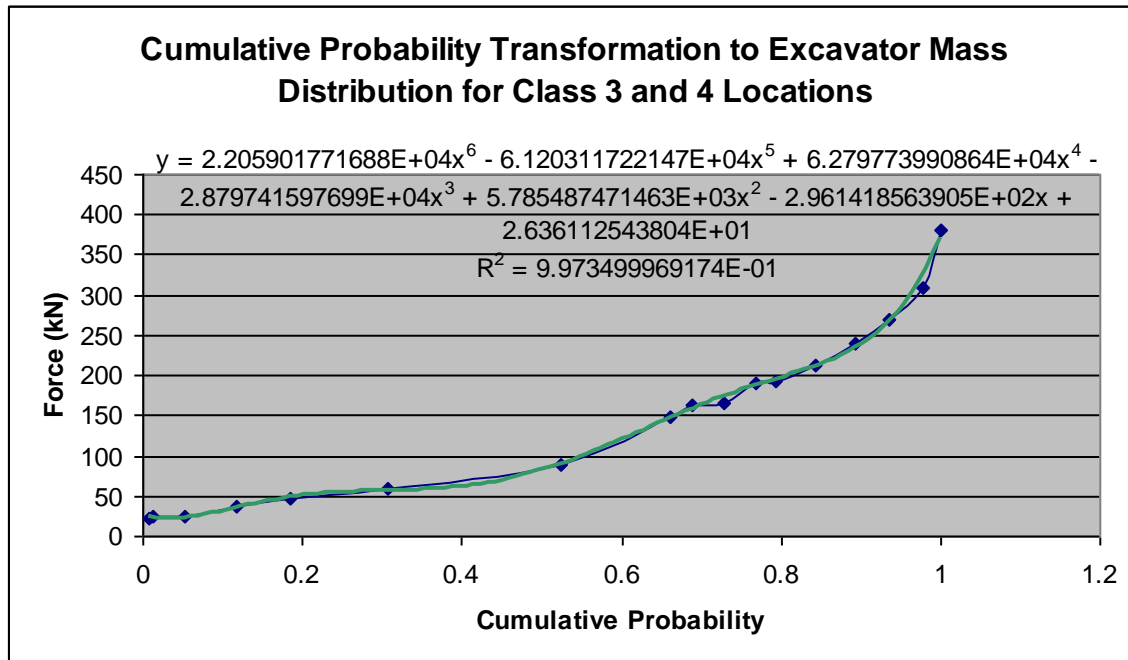
in that Reference, the entire excavator mass distribution may be applied for Class 1 and Class 2 locations, while a sub-set of that distribution (i.e., excluding excavator masses in excess of 40 tonnes) is applicable to Class 3 and 4 locations. By performing cumulative probability transformations of the excavator mass distributions, and applying Equation 8, an excellent 6th-order polynomial curve fit could be made to the data for both the Class 1/2 and Class 3/4 datasets, as illustrated in Figure 9 and Figure 10, respectively. These regression functions were employed directly in the Monte Carlo simulations.

Figure 9



¹⁶ Driver, R.G., Zimmerman, T.J.E., "A Limit States Approach to the Design of Pipelines for Mechanical Damage", Fig.1.

Figure 10



Excavator Tooth Dimensions: Length (L) and Width (W)

The excavator bucket tooth size parameters tooth length (L, mm) and tooth width (W, mm) have been shown to be a function of excavator mass (m_{ex} , tonnes):¹⁷

$$(L + W) = 29.4 \cdot m_{ex}^{0.400}$$

Equation 9

$$L = 24.6 \cdot m_{ex}^{0.420}$$

Equation 10

These parameters were therefore derived as functions of the excavator mass distribution.

Dent Depth (H)

Dent depth has been shown to be a function of pipe diameter, ultimate tensile strength, excavator tooth Length, wall thickness, operating pressure (P_{op}) and excavator force.¹⁸

¹⁷ Roovers et al, "EPRG Methods for Assessing the Tolerance and Resistance of Pipelines to External Damage", Proceedings of Joint EPRG/PRCI Conference on Pipeline Technology, Vol. II, 2000, pp 419-420.



$$P_r = \sqrt{t^3 \cdot UTS \cdot L} \left[1 + 0.7 \left(\frac{P_{op} \cdot D}{t \cdot UTS} \right) \right]$$

Equation 11

Where,

- UTS = Ultimate Tensile Strength (MPa),
L = Tooth Length (mm),
P_{op} = Maximum Operating Pressure (MPa),
D = Pipe Diameter (mm),
t = Pipe wall thickness (mm),
P_r = Pipeline Resistance Parameter (mm(N)^{0.5}), where:

$$\text{If } P_r \leq 2000 \text{ mm} \cdot \sqrt{N} : H = \left(\frac{F_d}{0.007 \cdot P_r} \right)^2$$

Equation 12

$$\text{If } P_r > 2000 \text{ mm} \cdot \sqrt{N} : H = \left(\frac{F_d}{0.31 \cdot \sqrt{P_r}} \right)^2$$

Equation 13

Where,

- F_d = Denting Force (kN),
H = Dent depth, measured after damage under pressure (i.e., after re-rounding under pressure) (mm).

A relationship exists between H and H_o (the dent depth prior to re-rounding under pressure):¹⁹

$$H_o = 1.43 \cdot H$$

Equation 14

¹⁸ ibid, pp 405-425.

¹⁹ ibid

Gouge Depth (d_g)

In Reference 12 reference was made to a judgment-based decision to assume that the gouge depth distribution could be defined as a random variable described by a Weibull distribution having $\mu = 0.5$ mm and $\sigma = 0.5$ mm. Conversations with researchers who were involved in full-scale experimental testing of 3rd Party damage revealed an unpublished dataset showing that gouge depth is a function of excavator force. A straight-line regression was found to fit this dataset having the form:

$$\text{Gouge Depth(in)} = 3.268 \times 10^{-4} \cdot F_d (\text{kN}) - 5.851 \times 10^{-3}$$

Equation 15

It should be noted that the 50th percentile force from Figure 9 is approximately 100 kN. If this value is substituted into Equation 15, a gouge depth of 0.027" is obtained, which corresponds very closely to the mean value of 0.5 mm that is cited in Reference 12.

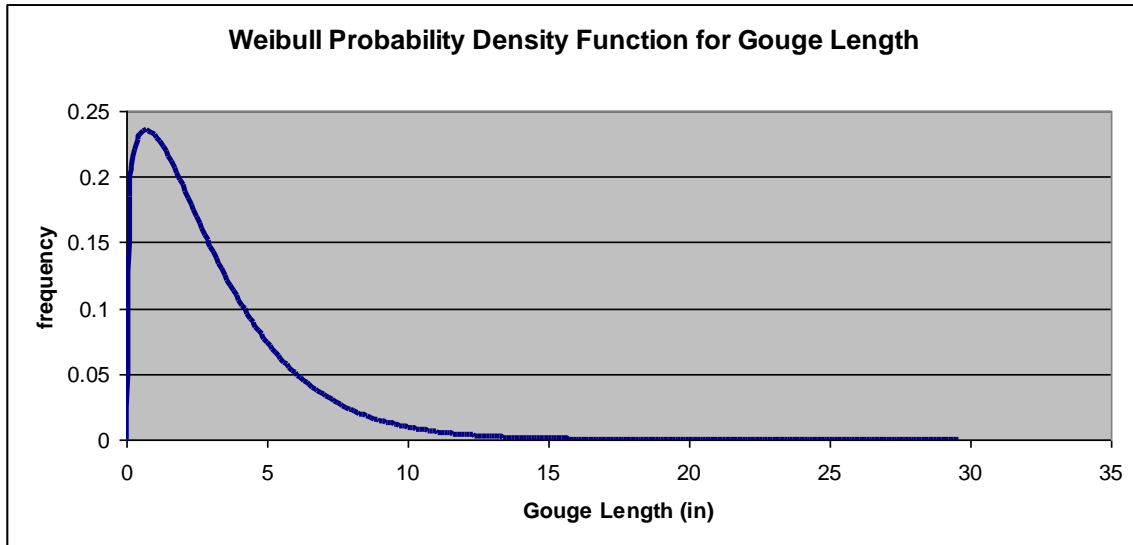
Accordingly, it was decided to correlate the gouge depth distribution to the excavator force distribution by means of Equation 15.

½ Gouge Length (c_g)

References 12 and 13 were cited for the purposes of establishing a basis for a gouge length distribution. It was determined that unlike gouge depth, gouge length is independent of other variables such as excavator force. In Reference 12, the gouge length distribution was described using a Weibull distribution having a mean of 6.0 in., and a COV of 1.25. In Reference 13, gouge length was described as having an approximate value of 3 in, and an upper-bound value of 25 in. It was noted that the dataset compiled in Reference 13 was derived from mechanical damage defects that failed in-service, and so the upper-bound gouge length may be taken as a statistical outlier. On the basis of this review, it was decided to describe the gouge length distribution as a Weibull distribution, having the shape parameters $\alpha = 1.2$ and $\beta = 3.2$. This distribution is illustrated in Figure 11.



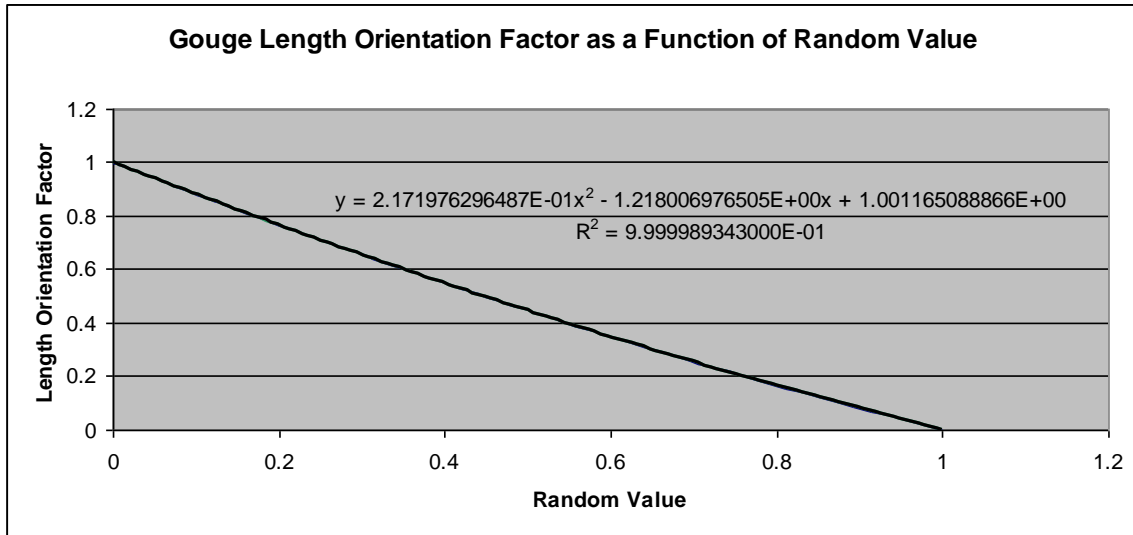
Figure 11



Because gouges may be randomly oriented with respect to the axis of the pipe, a Gouge Orientation Factor is applied against the gouge length. This is derived by recognizing the fact that the projected length of a gouge on the pipe axis is proportional to the cosine of the angle between the gouge and the pipe axis. The Gouge Length Orientation Factor, therefore varies between 0 and 1 and is equal to the cosine of a uniform distribution of random angles between 0 and $\pi/2$ radians. A cumulative probability transformation on this distribution was performed, and a 2nd order polynomial curve fit was derived for this function, as depicted in Figure 12.

This polynomial function was employed directly within the Monte Carlo simulation.

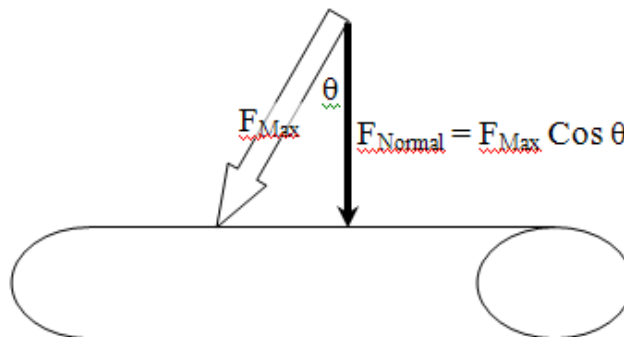
Figure 12



Off-Angle Force Reduction Factor

Only when the excavator force is applied normal to the pipeline can the full penetrating force of the excavation equipment be brought to bear against the pipeline. When the applied force is at an angle θ to the pipe, the component of the maximum applied force that is directed towards penetration of the pipeline is equal to $F_{\text{Max}} \cos \theta$, as illustrated in Figure 13.

Figure 13
Off-Angle Force Reduction Factor



As was argued in Reference 12, since the angle of the angle of application of excavator force may be equally likely to be any angle between 0 and 90 degrees, the Off-Angle Force Reduction Factor is best described as a uniform distribution between 0 and 1.



Operator Control Factor

As discussed in Reference 12, the operator of a piece of excavation equipment will, in most cases, apply a load that is considerably less than the maximum quasi-static load. The typical actual capacity at which the machine is used will depend on the soil type and how aggressively the operator digs. It may also be expected that an operator may dramatically cut back on the load if he detects a foreign object. This may be particularly true for gouge-in-dent type damage which is inflicted more gradually than puncture damage. Because of the uncertainty regarding the distribution of applied force, it was decided to follow the example of Reference 12 and calibrate the model against “Probability of Failure, Given a Hit” data contained in that Reference by means of the Operator Control Factor.

2.3.2.2 Test of Failure Due to Puncture

Puncture failure has been empirically described by the model described by Chen and Nessim.²⁰

$$R = \left[1.17 - 0.0029 \cdot \left(\frac{D}{t} \right) \right] \cdot (L + W) \cdot t \cdot \sigma_u + E_R$$

Equation 16

Where:

R	= The resistance to puncture (N)
D	= Pipe Diameter (mm)
t	= Wall Thickness (mm)
L	= Excavator Tooth Length (mm)
W	= Excavator Tooth Width (mm)
σ_u	= Ultimate Tensile Strength (MPa)
E_R	= Model Error (N)

This is the same limit state equation that was used to define puncture resistance in Reference 12.

²⁰ Chen, Q., Nessim, M., “Reliability-Based Prevention of Mechanical Damage to Pipelines”, PRCI Report No. PR-244-9729, August, 1999, p. 22.

Input Parameters

With the exception of the Operator Control Factor, all of the input parameters that are required for the puncture model have been defined in the discussion on the gouge-in-dent model. Therefore, in order to avoid repetition, only the Operator Control Factor will be described in this section.

Operator Control Factor

As was done for the gouge-in-dent model and in Reference 12, due to the lack of certainty regarding the distribution that describes the degree of operator control, the puncture model was calibrated against “Probability of Failure, Given a Hit” data contained in Reference 12.

2.3.2.3 Monte Carlo Simulation

Monte Carlo simulation is a numerical approach for arriving at a solution when the variables within a mathematical expression are best described as random variables derived from probability density functions, rather than discrete values, as is the case with a conventional deterministic analysis. When used as part of a reliability analysis, the mathematical expression is known as a ‘limit state equation’, and the usual objective of the analysis is to estimate the probability of an event or ‘limiting condition’ occurring.

The limiting condition is usually one which describes the onset of failure, or some other undesirable event. In the case at hand, two limit state equations are used; one to define the onset of gouge-in-dent failure (Equation 6) and the other to define the onset of failure due to puncture (Equation 16). The probability of failure given a hit due to gouge in dent is obtained by employing a Monte Carlo Simulation to determine the frequency of occurrence (over a set number of iterations) of events where the operating hoop stress due to internal pressure (σ_h) exceeds the operating stress at failure, as defined in Equation 6. Similarly, the probability of failure given a hit due to puncture is obtained by employing a Monte Carlo Simulation to determine the frequency of occurrence (over a set number of iterations) of events where the factored excavator force exceeds the resistance, R , as defined in Equation 16. The overall probability of failure given a hit is determined by executing the Monte Carlo Simulations for gouge-in-dent and puncture simultaneously, and determining the frequency of occurrence (over a set number of iterations) of events where either the limit state for gouge-in-dent OR puncture is exceeded.

2.3.2.4 Modern Pipeline Adjustment Factor

A previous study investigated the effect of decade of construction on failure rates in the oil pipeline industry.²¹ That report determined that the normalized rate of 3rd Party Damage incidents, expressed in terms of [(% Incidents)/(% Length of Infrastructure)] varied by decade of construction, such that the most modern pipelines that were considered in the study (those from the 1990s) had a normalized incident rate that was

²¹ Kiefner, J.F., and Trench, C.J., “Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction”, December, 2001.

30% of the pipeline infrastructure as a whole. In the report, this reduction in incidence rates for 3rd Party Damage was attributed to the damage prevention programs that are designed into modern pipelines due to the recent focus on this failure mechanism. To account for this effect of modern construction, a Modern Pipeline Adjustment Factor of 0.3 was applied to the failure frequency values derived from the reliability model described above.

2.3.2.5 Calibration

Calibration of this model was undertaken as described in the Sections describing the Operator Control Factor for each of the two limit states. This approach is consistent with what was done in Reference 12, and it was achieved utilizing the calibration data contained in that Reference.

As an added check on proper calibration, the results of the reliability analysis were compared against industry failure statistics due to 3rd Party Damage. A comprehensive report on failure statistics by cause for onshore hazardous liquid pipelines was published in 2010 by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration.²² That report covers accident statistics for the approximately 164,000 miles of onshore hazardous liquid pipelines in the United States for the period 2005 to 2009. Seventy-one failures were attributed to the cause “Excavation Damage” for that infrastructure over that time period. This equates to an average failure frequency of 5.412×10^{-5} failures/km.yr. This failure rate was compared against the predicted failure rates using the above approach (absent the Modern Pipeline Adjustment Factor) for the 36” dilbit pipeline operating in a land use classification of ‘remote’. Other factors assumed for the purpose of the analysis include a 3-day locate request response time, a wall thickness of 10.3 mm, and operating pressures ranging from 8707 kPa (80% SMYS) to 4354 kPa (40% SMYS). At 8707 kPa, the failure rate that was predicted using the above approach was 6.381×10^{-5} failures/km.yr, and at 4353 kPa, the predicted failure rate was 4.193×10^{-5} failures/km.yr. These values bracket industry average failure rates for 3rd Party Damage, which is a desirable outcome for a well-calibrated model.

2.3.3 Leaks Vs. Ruptures

It has been reported that the respective percentages of leak and rupture for 3rd Party Damage failures are 75% and 25%, based on the mechanical damage incidents reported to US Department of Transportation during 1984 to 1992.²³ Accordingly, 3rd Party Damage failure rates established by the reliability approach described above are sub-divided into leaks and failures in accordance with this guideline, with the hole-size for leaks assumed to be 1,000 mm², which corresponds to the approximate cross-sectional area of a back-hoe tooth, having dimensions of 10 mm x 100 mm.

²² U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration Report “Building Safe Communities: Pipeline Risk and its Application to Local Development Decisions”, October, 2010.

²³ Chen, Q. and Nessim, M., “Reliability-Based Prevention of Mechanical Damage to Pipelines”, PRCI Report No. PR-244-9729, August, 1999.

2.4. Equipment Failure

Equipment Failure encompasses the failure of non-pipe components and equipment, such as pumps, seals, valves, flanges, etc. By definition, therefore, all failures associated with this threat occur at stations where this sort of equipment is located, as opposed to along the pipeline right-of-way. Due to the varied forms, mechanisms of failure and associated materials that are included in this threat mechanism, no single limit state function or set of parameters can be defined that relate to this threat, and so no reliability-based approach exists to predict the frequency of occurrence of equipment failure. Instead, the approach that has been used to estimate the frequency of occurrence for this threat employs a baseline failure frequency derived from industry failure statistics.

A comprehensive report on failure statistics by cause for hazardous liquid pipelines was published in 2009.²⁴ These data report failure incidents for various causes and sub-causes occurring over the 170,000 mile hazardous liquid pipeline infrastructure in the United States over the period January 2002 to December 2005.* Failure incident data for four sub-causes were identified as being related to the major threat category of Equipment Failure. These were:

- Ruptured or leaking seal / pump packing (64 failures)
- Component failure (45 failures)
- Malfunction of control / relief equipment (45 failures), and,
- Stripped threads (30 failures)

Combined, these 184 failures over the four-year period over which data were collected represent a failure frequency of 1.691×10^{-4} failures/km.yr.

2.4.1 Leak, Rupture and Hole Size

In order to establish release outcomes associated with Equipment Failure, the PHMSA leak database (2002 -2009) was sorted for onshore, large-diameter (≥ 20 ") pipelines transporting hazardous liquids, and 21 failures were found that related to equipment failure. Spill volumes reported for these incidents were (in bbls): 0.024, 0.003, 75, 6, 700, 120, 2, 250, 3, 100, 788, 9762, 8, 12, 10, 10, 40, 13, 12, 10, 6.

Based on this information, it was decided to establish two frequencies; one for large leak, one for small leak.

Outflow calculations on a 1" hole operating at 8707 kPa established a leak rate of 971 bbls/hr. Therefore, assuming that the operators who reported their incident data would have achieved an average of a 10-hour response and containment time, we can

²⁴ Restrepo, C.E., Simonoff, J.S. and Zimmerman, R., "Causes, Cost Consequences, and Risk Implications of Accidents in US Hazardous Liquid Pipeline Infrastructure", International Journal of Critical Infrastructure", May, 2009.

* US incident statistics have been used in this report since they are more representative of a wide range of loss of containment incidents (for example, the NEB's incident database lists only those incidents that meet its definition of the term 'rupture'). Also, these statistics are recorded in a database that lends itself to sorting, and which contains information regarding individual incidents, such as contributing factors.

conservatively assume that the failures corresponding to leaks of 700 bbls, 120 bbls, 250 bbls, 100 bbls, 788 bbls, and 9782 bbls are 1" holes. For the remainder of the failures, a pinhole, with a diameter of 1.8 mm is assumed.

Therefore, the breakdown of failures by leak size is:

- 1" (25 mm) Hole: 29% of all Equipment Failures.
- 1.8 mm hole: 71% of all Equipment Failures

2.4.2 Segmentation

By definition, equipment failures occur only where non-pipe components and associated pressure-retaining equipment are present, such as at stations. For the purposes of the analysis, equipment failure frequency was therefore assigned at discrete locations corresponding to pumping stations. Failure frequency values (failures/yr) were derived by multiplying the failure frequency values obtained from industry failure statistics (1.691×10^{-4} failures/km.yr) by the length of the pipeline (1172 km). This gives a value of 0.1985 failures per year for the length of the dilbit pipeline. On this pipeline, there are 7 pump stations to distribute these 0.1985 failures each year among. Therefore, a failure probability was assigned to each pump station on the oil pipeline of $[0.1985/7] = 0.0284$ failures/year.

2.5. Incorrect Operations

Incorrect Operations failures are related to a failure to follow set procedures during the operation of a pipeline. The threat of incorrect operations does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Reflecting this fact, estimates of failure frequency were based on operating incident data related to this threat, modified by the results of the Operations Questionnaire that was administered during the Threat Assessment Workshop. This approach is similar to that described in the 2nd edition of API RP 581 "Risk Based Inspection Technology", where operations-related failure frequency is obtained by multiplying a baseline operations-related failure rate by a Management Systems Adjustment Factor, as highlighted below:

$$FF_{IO} = FF_{IO, Baseline} \times AF_{MS}$$

Equation 17

Where,

- FF_{IO} = Incorrect Operations failure frequency (failures/km.yr)
- $FF_{IO, Baseline}$ = Baseline failure frequency for incorrect operations derived from industry failure statistics
- AF_{MS} = Operational Management Systems Adjustment Factor (0.1 – 10.0)

2.5.1 Baseline Failure Frequency for Incorrect Operations

Reference 24 reports 61 failures attributed to incorrect operations over the 170,000 mile hazardous liquid pipeline infrastructure in the United States over the period January 2002

to December 2005. This equates to a failure frequency of 5.607×10^{-5} failures/km.yr. This value was employed as the baseline failure frequency for incorrect operations.

2.5.2 Operational Management Systems Adjustment Factor

During the Threat Assessment that was documented in Reference 1, an Operational Management Systems Questionnaire was administered. That questionnaire covered topics that were intended to gauge the performance of the Northern Gateway operations in terms of the causal factors of failures related to incorrect operations. As detailed in Reference 1, the results of the questionnaire were evaluated and scored, resulting in a score of 56.6 out of a possible 76 points (i.e., 74.3%).

Adopting the quantitative failure likelihood estimation approach of API RP 581, an Operational Management Systems Adjustment Factor is derived in accordance with the following expression:

$$AF_{MS} = 10^{[-0.02P_{Score}+1]}$$

Equation 18

Where,

P_{Score} = the percent score obtained on the Operational Management Systems Questionnaire.

Based on a P_{Score} value of 74.3%, AF_{MS} was determined to be 0.326.

From Equation 17, the Incorrect Operations failure frequency was therefore determined to be 1.828×10^{-5} failures/km.yr.

2.5.3 Leak, Rupture and Hole Size

In order to establish release outcomes associated with Incorrect Operations, the PHMSA leak database (2002 -2009) was sorted for onshore, large-diameter ($\geq 20"$) pipelines transporting hazardous liquids, and 10 failures related to incorrect operations were found. Spill volumes were (in bbls): 3416, 1821, 266, 45, 150, 325, 0.011, 10, 20, and 10.

Based on this information, it was decided to establish two frequencies; one for large leak, one for small leak.

Outflow calculations on a 0.6" hole operating at 8707 kPa established a leak rate of 350 bbls/hr. Therefore, assuming that the operators who reported their incident data would have achieved an average of a 10-hour response and containment time, we can conservatively assume that the failures corresponding to leaks of 3416 bbls, 1821 bbls, 325 bbls, 266 bbls and 150 bbls are 0.6" holes. For the remainder of the failures, a pinhole, with a diameter of 1.8 mm is assumed.

Therefore, the breakdown of failures by leak size is:

- 0.6" (15 mm) Hole: 50% of all Incorrect Operations Failures.
- 1.8 mm hole: 50% of all Incorrect Operations Failures

2.5.4 Segmentation

Dynamic segments were created based on pressure and wall thickness, and the length of each of those dynamic segments was determined. The failure probability due to incorrect operations per year of operation was then calculated by multiplying the length (in km) of each dynamic segment by the failure frequency (1.828×10^{-5} failures/km.yr).

2.6. Materials Defects

Materials Defects failures are failures that are attributed to pipe as a direct result of the presence of pipe body or seam weld defects.

The threat of manufacturing defects does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Therefore, the approach that was used to estimate the frequency of occurrence for this threat employs a baseline failure frequency derived from industry failure statistics, modified by an adjustment factor to account for modern pipeline materials, design, and installation practices, as illustrated in the equation below.

$$FF_{MD} = FF_{MD, Baseline} \times AF_{MC, MD}$$

Equation 19

Where,

- FF_{MD} = Estimate of materials defects failure frequency for Northern Gateway Pipelines (failures/km.yr)
- $FF_{MD, Baseline}$ = Baseline failure frequency estimate for materials defects failure, based on industry incident statistics
- $AF_{MC, MD}$ = Materials Defects Adjustment Factor to account for modern pipeline materials, design and construction

2.6.1 Baseline Failure Frequency for Materials Defects

Reference 24 reports 19 failures attributed to materials defects over the 170,000 mile hazardous liquid pipeline infrastructure in the United States over the period January 2002 to December 2005. This equates to a failure frequency of 1.746×10^{-5} failures/km.yr. This value was employed as the baseline failure frequency for materials defects.

2.6.2 Adjustment Factor to Account for Modern Construction

A review of the Materials Defects failure statistics contained in Reference 21 determined that the normalized rate of materials defects incidents, expressed in terms of $[(\% \text{ Incidents})/(\% \text{ Length of Infrastructure})]$ varied by decade of construction. In this respect, the most modern pipelines that were considered in the study (those from the 1980s and 1990s) had a normalized incident rate that was 15% of the pipeline infrastructure as a whole. To account for this effect, a Modern Construction Adjustment Factor of 0.15 was employed in the calculation of materials defects failure frequency in Equation 19, resulting in a failure likelihood of 2.619×10^{-6} failures/km.yr.

2.6.3 Leak, Rupture and Hole Size

In order to establish release outcomes associated with Materials Defects, the PHMSA leak database (2002 -2009) was sorted for onshore, large-diameter (≥ 20 ") pipelines with an installation year of 1990 or later, and transporting hazardous liquids. Two failure incidents were found; one a leak, and the other a rupture. Therefore, based on this industry experience, an assumption was made that 50% of all materials defects failures result in ruptures, and the other 50% result in leaks.

In order to establish a realistic hole size for leaks, crack mouth opening area calculations were performed based on the approach of BS 7910 "Guide on Methods for Assessing the Acceptability of Flaws in Fusion Welded Structures".

For the 36" dilbit pipeline, a crack length of 50 mm (1/2 of the critical through-wall flaw size for the 36" dilbit pipeline with a wall thickness of 10.3 mm, and operating at 8707 kPa) was modeled. These calculations established an equivalent hole diameter of 9.2mm. Therefore, this was the hole size assumed for leak-type failures attributed to materials defects on the 36" dilbit pipeline.

2.6.4 Segmentation

Dynamic segments were created based on pressure and wall thickness, and the length of each of those dynamic segments was determined. The failure probability due to materials defects per year of operation was then calculated by multiplying the length (in km) of each dynamic segment by the failure frequency (2.619×10^{-6} failures/km.yr).

2.7. Construction Defects

Construction Defects failures are failures that are attributed to construction or installation defects, such as girth weld defects.

The threat of construction defects does not lend itself to failure likelihood estimation using a reliability approach due to the lack of a limit state model that is supported by probability distributions for its input parameters. Therefore, the approach that was used to estimate the frequency of occurrence for this threat employs a baseline failure frequency derived from industry failure statistics, modified by an adjustment factor to account for modern pipeline materials, design, and installation practices, as illustrated in the equation below.

$$FF_{CD} = FF_{CD, Baseline} \times AF_{MC, CD}$$

Equation 20

Where,

- | | |
|---------------------|---|
| FF_{CD} | = Estimate of construction defects failure frequency for Northern Gateway Pipelines (failures/km.yr) |
| $FF_{CD, Baseline}$ | = Baseline failure frequency estimate for construction defects failure, based on industry incident statistics |
| $AF_{MC, CD}$ | = Construction Defects Adjustment Factor to account for modern pipeline materials, design and construction |

2.7.1 Baseline Failure Frequency for Construction Defects

Reference 24 reports for three sub-causes related to the major threat category of Construction Defects Failure. These were:

- Body of pipe (dents, etc.) (16 failures)
- Butt weld (15 failures), and
- Fillet weld (9 failures)

Combined, these 40 failures over the four-year period over which data were collected represent a failure frequency of 3.676×10^{-5} failures/km.yr. This value was employed as the baseline failure frequency for construction defects.

2.7.2 Adjustment Factor to Account for Modern Construction

A review of the Construction Defects failure statistics contained in Reference 21 determined that the normalized rate of materials defects incidents, expressed in terms of $[(\% \text{ Incidents})/(\% \text{ Length of Infrastructure})]$ varied by decade of construction. In this respect, the most modern pipelines that were considered in the study (those from the 1980s and 1990s) had a normalized incident rate that was 60% of the pipeline infrastructure as a whole. To account for this effect, a Modern Construction Adjustment Factor of 0.60 was employed in the calculation of construction defects failure frequency in Equation 20, resulting in a failure likelihood of 2.206×10^{-5} failures/km.yr.

2.7.3 Leak, Rupture and Hole Size

In order to establish release outcomes associated with Construction Defects, the PHMSA leak database (2002-2009) was sorted for onshore, large-diameter ($\geq 20"$) pipelines with an installation year of 1990 or later, and transporting hazardous liquids. Three failure incidents were found; all leaks. This is consistent with conventional wisdom that absent some large-scale outside force, failures due to construction defects (which are dominated by leaking girth welds, which are out-of-plane with the principal operating stresses) fail by a leak mechanism, rather than rupture. Therefore, based on this industry experience, an assumption was made that all Construction Defects fail by a leak mechanism, rather than rupture.

In order to establish a realistic hole size for leaks, crack mouth opening area calculations were performed based on the approach of BS 7910 "Guide on Methods for Assessing the Acceptability of Flaws in Fusion Welded Structures". For the purposes of the calculation, a crack length of 25 mm was assumed (which is conservative, given the detection thresholds for current girth weld inspection technology). When this analysis was applied to the 36" dilbit pipeline with a wall thickness of 10.3 mm w.t. and operating at 8707 kPa, these calculations established an equivalent hole diameter of 1.8 mm (i.e., a pinhole). Therefore, this was the hole size assumed for leak-type failures attributed to construction defects on the 36" dilbit pipeline.

2.7.4 Segmentation

Dynamic segments were created based on pressure and wall thickness, and the length of each of those dynamic segments was determined. The failure probability due to construction defects per year of operation was then calculated by multiplying the length (in km) of each dynamic segment by the failure frequency (2.206×10^{-5} failures/km.yr).



2.8. Geotechnical / Hydrological Failures

In order to assess the degree of threat that a pipeline will be exposed to, a thorough evaluation of all information along the length of the pipeline was completed. To ensure completeness, this review included published information such as soils maps, topographic maps, hydrological maps, pipeline alignment sheets, incident reports related to ground movement, hydrological events, and floods, studies, texts, and engineering reports.

A full description of the approach that was adopted is provided in the Report on Geohazard Assessment.²⁵

²⁵ Cavers, D.S and Davidson, C. "Report on Quantitative Geohazard Assessment for the Proposed Northern Gateway Pipelines", AMEC Report #1166-RE-20120417, April 30, 2012



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ENBRIDGE NORTHERN GATEWAY PROJECT

Semi-Quantitative Risk Assessment

**SUBMITTED IN RESPONSE TO JOINT REVIEW PANEL INFORMATION REQUEST NUMBER
8.1(B)**

**Attachment 3: Simulations of Hypothetical Oil Spills from
the Northern Gateway Pipeline Centerline
Rev-U**

REPORT

**Simulations of Hypothetical Full-Bore Rupture
Oil Spills from the Northern Gateway Pipeline
Rev-U**

ASA Project Number: 2011-298

PREPARED FOR:
WorleyParsons Canada

AUTHOR:
Chris Galagan

DATE SUBMITTED
13 March, 2012

Introduction

This brief report documents the model inputs, calculation methods and model outputs from simulations of full-bore rupture spills from the Rev-U pipeline.

Spill Scenarios

The OILMAP Land model was used to simulate 1165 individual spills along the length of the pipeline route. The full-bore rupture spills include volumes ranging from 986 to 8,484 m³ (see Figure 1). The spill point locations and volumes were provided by WorleyParsons Canada on 25 January, 2012.

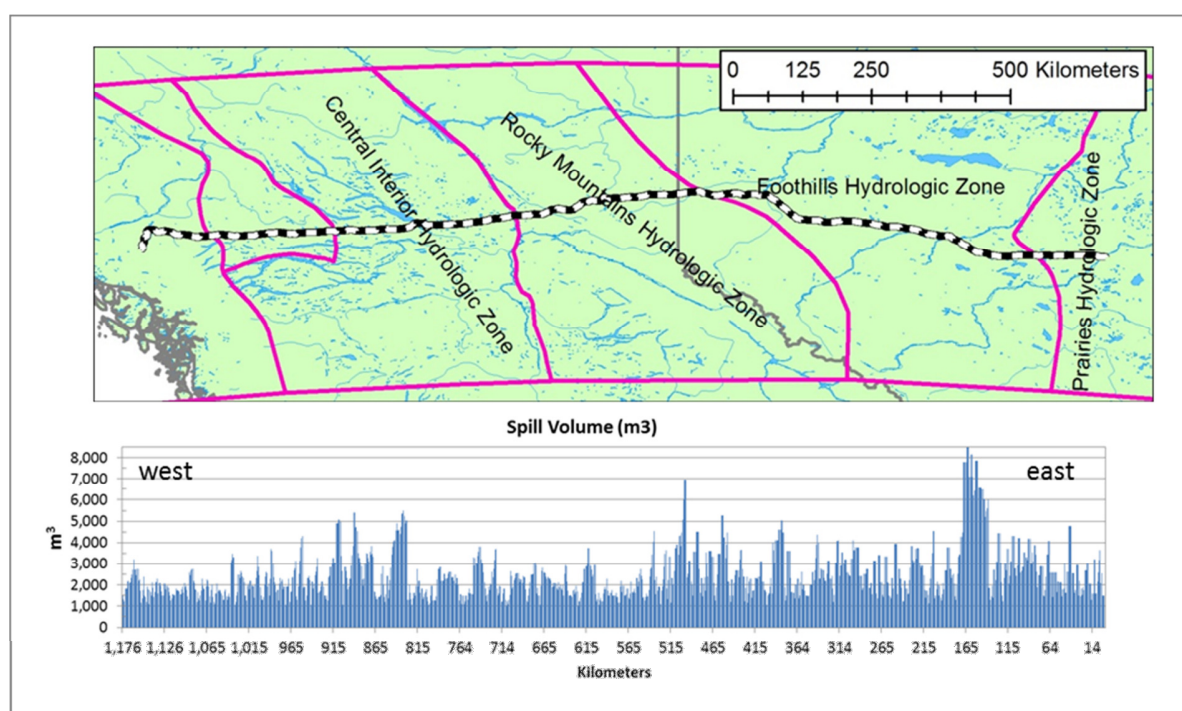


Figure 1. Map showing the pipeline route (above) and graph of the full bore rupture spill volumes used in the model simulations.

The model was allowed to run 12 hours from the start of the each spill, so the resulting spill pathways are time constrained. It is possible for any of these spills to stop flowing prior to 12 hours if all of the spilled volume has been released and this volume is accounted for. For example, if an individual release duration is 3 hours and the oil flows over land and pools in a depression in the land surface in less than 12 hours; the resulting pathway provides the maximum predicted oil path. In this case the oil cannot move any farther because the entire spill volume is contained on land. On the other hand, if the spill immediately enters a river and travels downstream, the model is stopped after 12 hours, even if there is oil available in the river to continue on downstream.

Environmental Conditions

River flow used for all of the modeling corresponds to the maximum monthly discharge condition. Maximum monthly discharge was computed using historical data from gages within each of the hydrological zones encompassing the pipeline route. The maximum monthly discharge is defined as the highest of the mean monthly flows recorded at each gage for the entire period of record. This flow condition frequently corresponds to the spring runoff period. Using the maximum monthly discharge data derived from the stream gages, AMEC (Monica Wagner, personal communication) determined the relationship between the drainage area and flow for each stream reach. ASA used this relationship to determine stream flow for every stream reach of a known drainage area. Drainage areas were determined using the CDED elevation data.

Table 1. Flow-drainage area relationships for maximum monthly flow conditions provided by AMEC (Monica Wagner, 23 March, 2011).

Hydrologic Zone	Maximum Flow Month	Applicable Drainage Areas (km ²)	Max Monthly Flow	
			$Q=a*DA^b$	
			a	b
Prairies	April	All	0.0077	0.923
Foothills	April	0 - 450	0.0093	0.9626
	May	> 450	0.0022	1.1978
Rocky Mountains	May	0 - 1,000	0.0341	1.0388
	June	> 1,000	0.0154	1.1524
Central Interior	May	0 – 1000	0.0815	0.7947
	April	> 1000	0.0257	0.9691
Central Mountains	June	All	0.0634	0.9808
Coastal Mountains	June	All	0.4887	0.8111

The mean annual flow for each stream reach was determined using the same methodology but with annual mean flow data from selected stream gages. Table 2 provides the drainage area and flow relationships for corresponding to the mean annual flow condition.

Table 2. Flow-drainage area relationships for mean annual flow conditions provided by AMEC (Monica Wagner, February, 2012).

Hydrologic Zone	Mean Annual Flow	
	$Q=a*DA^b$	
	a	b
Prairies	0.00060	1.1399
Foothills	0.00110	1.2252
Rocky Mountains	0.0117	1.0967
Central Interior	0.00930	0.960
Central Mountains	0.0242	1.0124
Coastal Mountains	0.3329	0.7797

ASA used the method developed by Jobson (Jobson, 1996) to calculate current speed for each stream reach using flow and drainage area values as defined above.

$$V_p = 0.094 + 0.0143 \times (D'_a)^{0.919} \times (Q'_a)^{-0.469} \times S^{0.159} \times \frac{Q}{D_a}$$

V_p = current speed

D_a = drainage area

S = reach slope

Q_a = mean annual discharge

Q = maximum monthly discharge

Land elevation data obtained from the Canadian Digital Elevation Data (CDED) web site (www.geobase.ca) were used by the model to determine overland flow pathways for the spilled oil. For oil in any single grid cell, the model moves the spill to the lowest of the 8 neighboring cells using the standard D8 method (O'Callaghan and Mark, 1984). The data have a vertical resolution of 1 meter, and because of this the land surface is represented as a series of flat terraces with a one-meter vertical separation. One way to calculate the downslope direction in the flat areas is to apply a very small (1 cm) offset, either positive or negative, randomly to every elevation grid cell. This random offset allows a downslope path to be calculated and because the elevation values are to the nearest meter, adjusting the values by 1cm has negligible effect. This method works well and the overland pathways determined are reasonable.

Description of the OILMAP Land Model

The OILMAP Land model is used to determine the overland and downstream pathways of spills from pipelines where data describing the terrestrial and surface water environments are minimal and hundreds of individual spill simulations are required to determine spill pathways from any point along the pipeline. The land surface is defined by an elevation grid, typically with cells no smaller than 10 meters by 10 meters, so that small features such as ditches that steer oil are not represented. Streams are represented by a network of single lines and lakes/ponds/estuaries as polygons. Streams are defined by a single width and no depth.

Overland Transport

Starting at the spill location, the model determines the steepest descent direction in the eight adjacent cells of the elevation grid. The oil moves to the neighboring cell with the lowest elevation. This process repeats successively until a flat area or depression is reached. In a depression area, the depression is filled before the spill continues down slope. Overland flow of the oil continues until the path reaches a stream or other surface water feature, or until the total spill volume is depleted from loss to the land surface and evaporation. The final spill path forms a chain of channels and pooled sections. A channel section is where no pooling occurs and the width of the spill path is dependent on the slope of the land surface. A pooled section consists of an area of one or more contiguous elevation grid cells that form a depression in which the spilled product has collected.

As the oil flows down slope, oil mass is lost through adhesion to surface vegetation, puddle formation on the ground surface and pooling in depressions. The rate of oil loss to these processes is dependent primarily on the physical characteristics of the land surface (vegetation type, land cover, soil type, and slope). Different land cover types retain different amounts of oil as a spill passes over the land surface. The volume of oil retained along the oiled path from the

adherence and puddle processes is defined as the path length times the path width times a constant oil thickness. The oiled path width is related to the slope of the land surface as determined from the elevation grid.

The constant oil loss thickness is specified for each land cover type defined in a land type grid that matches the size and extent of the elevation grid. Each cell in the land type grid is assigned an oil loss thickness so that as oil traverses the land the loss to each land type is calculated. This loss value varies between 2 and 200 millimeters for the range of land cover types typically encountered. These oil loss rates are based on surface hydrologic studies (ASCE 1969, Kouwen 2001, and Schwartz et al 2002) for surface water runoff modeling.

Separate from adhesion and puddle losses, oil lost to pooling on the land surface is the volume of oil retained within depressions defined in the land elevation grid. The oil lost as oil traverses the land is the sum of adhesion, puddle formation, pooling in large depressions and evaporation.

The predicted overland travel path is only as good as the elevation data. Even with high resolution gridded data, features that steer oil are only captured with a site visit and field mapping. Land spill model results should be viewed with a clear understanding of how accurately the elevation data capture the land features over which the oil travels.

Water Transport

Once the spilled oil enters a stream it is transported through the stream network at a velocity defined by the speed and direction of surface currents in each stream reach. While in the stream network, oil is lost by adhesion to the shore and by evaporation to the atmosphere. A maximum total travel time and stream velocity control the distance traveled downstream. Travel times are typically defined in spill response plans as the time required to respond to and stop a catastrophic release. Oil is modeled to travel downstream until all available oil is lost to the shoreline or to evaporation, or the simulation reaches the maximum downstream travel time.

When oil encounters a lake the slick will spread across the lake surface until it covers the entire lake or it reaches a minimum thickness. If the minimum thickness is reached, spreading stops and the oil travels no farther. The minimum thickness can be varied according to the oil type. If oil covers the lake surface before reaching the minimum thickness it continues down any out-flowing streams at the surface current velocity specified for the stream reach.

Oil loss to stream shorelines occurs as oil is transported downstream by surface currents. Five different stream shore types are defined, each with a specified bank width and oil loss thickness. Oil volume lost to the shoreline is calculated as the length of the shoreline oiled times the specified bank width times the thickness. Typical shoreline loss values are shown below:

Shore Type	Shore Width (m)	Oil Thickness (mm)	Hydrologic Zone(s)
Bedrock	0.5	1 – 4	
Gravel	1	2 – 15	Rocky Mountains Central Mountains
Sand/Gravel	2	3 – 20	Foothills Central Interior Coastal Mountains
Sand	5	4 – 25	Prairies
Marsh	20	6 – 40	

Because streams are defined by single lines with a fixed width, braided streams and streams with numerous islands and sand bars are underrepresented in terms of the length of shoreline available to accumulate oil.

Aside from the processes described above, the OILMAP Land model does not account for a number of oil fate processes that occur when oil travels down rivers. These processes include: collection of oil in quiescent pools which may exist in meander bends or in other places where currents are slow enough for oil to collect; entrainment of oil into the water column by turbulent mixing present in rapids or spillways; adherence of small oil droplets to fine sediment particles that potentially sink to the bottom and accumulate in river bed sediment; creation of tar balls and tar mats from weathered oil that may collect on the river bed; sequestration of oil to the groundwater or hyporheic zone below the river bed. All of these processes are important in determining the ultimate fate of the spilled oil, but they are beyond the capabilities of the data utilized and the OILMAP Land model.

Evaporation

Oil evaporates as it spreads over land or water. The most volatile hydrocarbons (low carbon number) evaporate most rapidly, typically in less than a day and sometimes in under an hour (McAuliffe, 1989). The spill model uses the Evaporative Exposure model of Stiver and Mackay (1984) to predict the volume fraction evaporated.

Several simplifying assumptions are made that directly affect the amount of oil predicted to evaporate. In general, the rate of evaporation depends on surface area, oil thickness, and vapor pressure, which are functions of the composition of the oil, wind speed and air and land temperature. The mass of oil evaporated is particularly sensitive to the surface area of the spreading oil and the time period over which evaporation is calculated. On the land surface, area and evaporation time are functions of the slope defined by the elevation grid. Steeper slopes cause the oil to travel faster but along a narrower path, while a lower slope slows the speed of advance and increases the width of the oiled path.

In the stream network, oil surface area and evaporation time are functions of the stream surface area (total length of the oiled stream times the fixed width) and stream velocity. Oil loss to evaporation ceases once the total oil spill volume is released and overland travel stops, or if oil enters a stream, once the stream maximum travel time is reached and flow in the stream network stops. In reality, oil will continue to evaporate from the ground or water surface, increasing the total evaporation amount. This conservative calculation of evaporative loss is consistent with a worst-case scenario approach.

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ENBRIDGE NORTHERN GATEWAY PROJECT

Semi-Quantitative Risk Assessment

**SUBMITTED IN RESPONSE TO JOINT REVIEW PANEL INFORMATION REQUEST NUMBER
8.1(B)**

**Attachment 4: Report on Quantitative Geohazard
Assessment**

**Report on
Quantitative Geohazard Assessment
Proposed Northern Gateway Pipelines**

Submitted to:

Northern Gateway Pipelines Inc.
Calgary, Alberta

Submitted by:

**AMEC Environment & Infrastructure,
a Division of AMEC Americas Limited**
Burnaby, BC

April 30, 2012

AMEC File: EG0926008 2100 800

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IMPORTANT NOTICE

This report was prepared exclusively for Northern Gateway Pipelines Inc. by AMEC Environment & Infrastructure, a wholly owned subsidiary of AMEC Americas Limited. The quality of information, conclusions and estimates contained herein is consistent with the level of effort involved in AMEC services and based on: i) information available at the time of preparation, ii) data supplied by outside sources, and iii) the assumptions, conditions and qualifications set forth in this report. This report is intended to be used by Northern Gateway Pipelines Inc. only, subject to the terms and conditions of its contract with AMEC. Any other use of, or reliance on, this report by any third party is at that party's sole risk.

EXECUTIVE SUMMARY

This report presents the results of an expanded quantitative geohazard assessment to identify and characterize geohazards that could potentially affect the proposed Northern Gateway Pipeline Project diluted bitumen and condensate pipelines proposed to be constructed between Bruderheim, Alberta and Kitimat, British Columbia. The geohazard assessment discussed in this report is part of a wider hazard and risk assessment for the pipelines and other infrastructure being carried out by others and the results are intended to be incorporated into an overall pipeline risk assessment.

An initial geohazard assessment for the Project was carried out based on Route Revision (Rev) R, and was presented in the May 2010 filing in Appendix E, "Overall Geotechnical Report" in Volume 3. The current study expands on the existing qualitative geohazard assessment presented in the previous Project filings but excludes discussion of the consequences since they are discussed within the overall pipeline risk assessment. The present geohazard assessment was undertaken with respect to a Loss of Containment (LoC) event. The previous qualitative assessment included definition of 170 individual geohazard occurrences within 13 categories which were incorporated into the present updated work as applicable. However, it should be noted that the present report work deals strictly with events with the potential for loss of containment and thus some of the geohazards in the previous work, such as wind erosion, do not appear in the present assessment.

The assessment was made on the basis of the Rev U route. The hazards assessed included mass movement events (deep-seated slides, shallow to moderately deep slides, and rockfall), stream flow and erosion events (scour, lateral migration, avulsion and debris flow), avalanches, and seismically triggered movements such as lateral spreading. No rock topples, rock avalanches, or sackung failures that would affect the proposed route have been identified and so are not included in the foregoing list. The locations of all geohazards were reassessed relative to the previous work and were defined to resolutions of 50 m along the route. Start and end kilometre locations were assessed relative to the route stationing. A total of 346 geohazard occurrences were defined.

The assessments of certain hazards were not limited to the Project Assessment Corridor, which is typically 1 km wide. Thus, hazards outside this corridor that could potentially affect the pipeline were assessed as far from the Rev U centerline as necessary to make sure that all applicable geohazards were included. Thus, rockfall, avalanches, debris flows and various forms of slides were assessed to distances of sometimes several kilometres from the Rev U route and were typically assessed to the height of land. Assessments of other hazards also extended outside the corridor as necessary, for example, lateral erosion and avulsion.

A susceptibility assessment approach was used as defined in Rizkalla (2008) within the framework of a quantitative hazard assessment to determine a predicted likelihood of failure. The method developed for this project uses four key index values, or factors, to provide a numerical expression to estimate the susceptibility of the pipeline to particular geohazards at discrete locations.

In this study, the following definitions were used:

Risk = Probability of Hazard Occurrence x **Vulnerability** of the Pipeline to the Hazard x **Consequences**

Probability of a geohazard causing a LoC event = **Probability** of Hazard Occurrence x **Vulnerability** of the Pipeline to the Hazard

For the purposes of this assessment, the probability of pipeline loss of containment due to discrete geohazards has been approximately assessed based on expert judgement including input from an expert panel. Results are expressed as events/year per linear section of pipeline. Because the results are expressed quantitatively, the assessment is considered to be quantitative and has been based on judgement.

As defined above, susceptibility is the product of the factors for occurrence, frequency, vulnerability and mitigation. Susceptibility to a loss of containment (FLOC) event expressed in terms of events per year at any location or segment (i) is expressed numerically as:

$$\text{Susceptibility} = F_{\text{LOC}(i)} = I_{(i)} \times F_{(i)} \times V_{(i)} \times M_{(i)}$$

A similar form of this method was used for geohazard assessment of the Mackenzie Valley Gas Pipeline Project, previously reviewed by the National Energy Board, and was accepted as a suitable approach in the NEB's Reason for Decision (National Energy Board, 2010).

It should be recognized that the results of the assessment are conditional on the application of the proposed or equivalent mitigations. The mitigations have been selected in accordance with standard and appropriate pipeline construction practices. The mitigation strategies and locations shown are preliminary and will be further considered and refined at the detailed engineering stage of the Project. A summary of the mitigation methods considered for each defined geohazard is contained in the report appendices.

The results of the geohazard analyses are summarized relative to the various geohazards as well as individual description sheets for each individually identified hazard listed sequentially by Rev U kilometre post.

The frequency of loss of containment is presented for each specified hazard impact location relative to the Rev U chainage. The mitigated frequency values typically ranged from 1×10^{-10} to 1×10^{-4} events/year.

1.0 INTRODUCTION

AMEC Environment & Infrastructure (AMEC), a division of AMEC Americas Limited, was retained by Northern Gateway Pipelines Inc. (Northern Gateway) to provide geotechnical engineering services in support of geohazard assessments for the proposed Northern Gateway Pipeline Project route. The purpose of the geohazard assessments were to identify and characterize geohazards that could potentially affect the planned diluted bitumen and condensate pipelines proposed to be constructed between Bruderheim, Alberta and Kitimat, British Columbia.

The present geohazard assessment was undertaken with respect to a Loss of Containment (LoC) event. The geohazard assessment has considered that all loss of containment events would be full rupture events regardless of the actual size of the opening in the pipeline. This is a conservative assumption because there is a broad spectrum of opening sizes from full bore rupture down to pin-holes that could be considered under various geohazard scenarios.

At this time, non LoC events such as damage to pipeline coating are not included in this assessment. The assessment was made with respect to pipeline route Revision (Rev) U. Note that some of the previous geotechnical documentation refers to Rev R. While the kilometre posts and differences vary along the route, Rev R route is approximately 3.4 km shorter than Rev U.

The geohazard assessment discussed in this report is part of a wider hazard and risk assessment for the pipelines and other infrastructure being carried out by others.

1.1 Purpose and Nature of a Geohazard Assessment

Relative to other types of hazards, geohazards represent a special class of potential threats to a pipeline (Rizkalla, 2008). A geohazard, as defined in this report, is a threat related to a geological, geotechnical, or hydrotechnical condition or process that may exist along the pipeline route.

A geohazard assessment is a means of identifying and characterizing potential geohazards for the purposes of evaluating the susceptibility of the pipeline to damage along the planned right-of-way. In this report, the geohazard assessment is viewed from the perspective of vulnerability. Vulnerability considers the potential for a given geohazard occurrence to damage the pipeline and that not all geohazard occurrences may damage the pipeline to the point that a LoC event occurs.

The purpose of this report is to present the methods, assumptions and results of the geohazard assessment. As indicated, the results are intended to be incorporated into an overall pipeline risk assessment. The study expands on the existing qualitative geohazard assessment presented in the previous Project filings. As noted above, the present study specifically focuses

on geohazards that might result in a loss of containment of the pipeline, but excludes discussion of the consequences since they are discussed within the overall pipeline risk assessment.

1.2 Organization

This geohazard assessment report includes the following subjects and sections:

- Section 2.0: Key definitions of concepts used in this assessment and limitations of the assessment.
- Section 3.0: Discussion of the difference between the present quantitative geohazard assessment and the previous qualitative geohazard assessment that was included in the Project filings to date.
- Section 4.0: Discussion of the present Quantitative Geohazard Assessment for the Project.
- Section 5.0: Results.
- Appendix A: Ranking sheets for each geohazard type to guide the assignment of factors to determine the frequency of loss of containment.
- Appendix B:
 - List of geohazards sorted by kilometre including start and end of the hazard along the route.
 - List of geohazards sorted by geohazard type.
 - Detailed records of the individual geohazards.
- Appendix C: Summary of proposed mitigations and engineering controls to reduce the frequency of loss of containment events from identified geohazards.

2.0 KEY DEFINITIONS AND CONCEPTS

2.1 Geohazard

A geohazard is a threat from a naturally occurring geological, geotechnical or hydrotechnical process or condition that may lead to damage. The process may be triggered by natural or anthropogenic causes. For the purposes of this assessment, the damage considered is loss of containment.

2.2 Risk

In the present assessment, a modified definition of the general expression of risk is adopted which incorporates pipeline vulnerability (the conditional probability of damage given the occurrence of a geohazard).

Risk = Probability of Hazard Occurrence x Vulnerability of the Pipeline to the Hazard x Consequences of Pipeline Failure

Probability of a geohazard causing a LoC event = Probability of Hazard Occurrence x Vulnerability of the Pipeline to the Hazard

This report discusses the probability or likelihood of various geohazard events and the conditional probability of loss of containment based on pipeline vulnerability. As discussed elsewhere in the report, the consequences of the event and, therefore, the risk will be discussed by others. However, it should particularly be noted that the terms risk and hazard are not interchangeable.

2.3 Qualitative, Semi-Quantitative and Quantitative Assessments

The results of a hazard assessment, and ultimately a risk assessment, can be expressed in the form of qualitative expressions (high/low), semi-quantitative (ranked indices) or quantitative (numerical probabilistic) expressions. The choice between these different forms of hazard assessment is often based on the availability and type of data and may evolve over the course of the project. It should be noted that all three approaches are recognized as appropriate in CSA-Z662 if applied within a well-defined framework in a systematic manner.

For the purposes of this assessment, the probability of pipeline loss of containment due to discrete geohazards has been approximately assessed. The assessment incorporates factors evaluated using expert judgement yielding results suitable for incorporation within the overall pipeline risk assessment. Results are expressed as events/year per linear section of pipeline. Because the results are expressed quantitatively, the assessment is considered to be quantitative and has been based on judgement.

2.4 Hazard Impact Zone

The hazard impact zone is defined as the overall zone of influence of a specific geohazard, and is defined in a 3-dimensional sense. That is, the start and end of the hazard zone along the proposed pipeline route have been defined relative to Rev U kilometre posts, and the depth of cover over the pipeline has been taken into consideration. The potential for a specific hazard to affect a buried pipeline affects the choice of mitigation for several hazards such as scour or lateral erosion.

The kilometre post locations used for this study were defined to a 50 m resolution which is considered appropriate given the level of detail provided in available imagery and previous reports.

2.5 Locations Assessed

The assessment was made on the basis of the Rev U route. As discussed in other filed materials, the Rev U route is the centerline of an assessment area and the actual pipeline centerlines may vary as additional work is undertaken. However, for the purposes of the assessment, a centreline is needed and the Rev U route was selected.

It should also be noted that the assessment of certain hazards was not limited to the Project Assessment Corridor, which is typically 1 km wide. Thus, hazards outside this corridor that could potentially affect the pipeline were assessed as far as necessary to make sure that all applicable geohazards were included. Thus, rockfall, avalanches, debris flows and various forms of slides were assessed to distances of sometimes several kilometres from the Rev U route and were typically assessed to the height of land. Assessments of other hazards also extended outside the corridor as necessary, for example, lateral erosion and avulsion.

2.6 The Necessary Role of Engineering Judgement in Geohazard Assessment

2.6.1 Engineering Judgement

Engineering judgement plays a key role in the hazard assessment presented in this report. Engineering judgement is the expression of the familiar experience and considers the form of the problem, location of the study area, type of development, methods of analysis and construction operational practice. In many geotechnical engineering applications, engineering judgement is relied upon to provide suitable bounds on potential outcomes based on a range of potential inputs and scenarios. The reliance on judgement in the geotechnical engineering community is necessary due to geological uncertainty that may vary over short and long distances. Engineering judgement has been and will be complemented by site specific ground investigations, available literature, case histories, and other such information. However, since subsurface knowledge is necessarily always incomplete, some level of engineering judgement is always required in geotechnical engineering.

2.6.2 Expert Panel

An expert panel was used to review the engineering judgements and assignments of the various factors on a general basis for the Project. The panel consisted of the following personnel:

- Gregg O'Neil, P.Eng., Klohn Crippen Berger, Calgary
- Pete Barlow, P.Eng., AMEC Environment and Infrastructure, Edmonton
- Rod Read, Ph.D., P.Eng. P.Geol., WorleyParsons, Calgary
- Clive MacKay, P.Eng. P.Geol., WorleyParsons, Calgary

2.6.3 Order-of-Magnitude Approach

During the assignment of the factors in the hazard assessment, a general order-of-magnitude approach was used in most cases. The order-of-magnitude approach is appropriate since the factors assigned were based on judgement. For example, a geohazard with annual probabilities of occurrence of 0.1, 0.01, 0.001 would correspond to 10 year, 100 year and 1000 year return periods, respectively. Other factors were similarly assessed based on orders of magnitude.

2.7 Susceptibility Assessment

A susceptibility assessment approach was used as defined in Rizkalla (2008) within the framework of a quantitative hazard assessment to determine a predicted likelihood of failure. The method developed for this project uses four key index values, or factors, to provide a numerical expression to estimate the susceptibility of the pipeline to particular geohazards at discrete locations. The evaluation relies on expert judgement. The factors, defined below, include Occurrence, Frequency, Vulnerability, and Mitigation.

$$\text{Susceptibility} = F_{\text{LOC}(i)} = I_{(i)} \times F_{(i)} \times V_{(i)} \times M_{(i)}$$

$I_{(i)}$ = Factor from 0 to 1 expressing the potential for the geohazard to occur at location i.

$F_{(i)}$ = Frequency of occurrence for a specific geohazard at location i expressed in events per year;

Where; $V_{(i)}$ = Vulnerability is the conditional probability of total system loss (LoC event) given the occurrence of a specific geohazard at a specific location. It can also be expressed as a fraction of total geohazard occurrences that would result in loss of containment. The unmitigated case assumes standard mainline construction and operation conditions.

$M_{(i)}$ = Mitigation effects expressed as a reduction factor on either $V_{(i)}$ or $F_{(i)}$ representing the resultant reduction in geohazard occurrence or reduced potential for loss of containment due to the geohazard occurrence at location i.

Thus, Susceptibility, $F_{\text{LOC}(i)}$ has units of frequency (events per year). The various parameters are discussed further below.

2.8 Occurrence Factor

The occurrence factor ($I_{(i)}$) expresses the potential for a particular geohazard to occur in a specific hazard impact zone. The factor is expressed as a value from 0 to 1, with 0 being defined as “not possible”, and 1 being “defined or documented occurrence”. Intermediate values were chosen based on comparison of the route conditions to the screening criteria based on expert judgement.

2.9 Frequency

The frequency values ($F_{(i)}$) used in this assessment represent the inverse of return period for the occurrence of a particular geohazard, expressed as events per year. The return periods provided are based on expert judgement. Guidance for the definition of the appropriate return period at each site is provided in the detailed process descriptions discussed later in this report.

In general, the return period considered provides an estimated frequency for all occurrences of a specific hazard at the given location, including damaging and non-damaging events. This is appropriate for many hazards such as deep-seated slides where the nature of the hazard means that all of the potential events might lead to a LoC event. However, there are a few

hazards (for example, avalanches) where both small and large events might occur. The small events are not considered to be events that would lead to a LoC event. In these cases, the frequency was selected for events sufficiently large to possibly trigger a LoC event.

2.10 Vulnerability Factor

Vulnerability ($V_{(i)}$) estimates the ability for the pipeline to withstand the imposed effects of a geohazard. The factor ranges from 0 (no damage in the event of the hazard occurrence) to 1 (loss of containment in all situations). For the purposes of this assessment, vulnerability is the fraction of geohazard occurrences at a specific location that would lead to a damaging event and, specifically, the fraction that would result in a loss of containment.

The fraction of events that could potentially cause a loss of containment was approximately evaluated and assigned for each specific geohazard type. This fraction within each hazard type was often based on relevant parameters such as the hazard scale, local terrain conditions and alignment geometry relative to the hazard. For example, the vulnerability of a pipeline crossing a channel subject to debris flow and avalanche hazards depends, in part, on channel gradient (which affects whether erosion or deposition are likely to occur). While many hazard attributes and terrain conditions that affect the vulnerability can easily be measured; the assigned numerical value must be estimated based on professional judgement and previous experience or records of events that have occurred on other pipelines.

As a further example, the authors are not aware of debris flows, avulsion or snow avalanche causing a LoC within British Columbia/Alberta on other large diameter pipelines such as the Vancouver Island and Kinder Morgan TransMountain lines. These hazards therefore have been assigned lower vulnerabilities relative to other hazards such as deep-seated slides which have several known cases where pipeline rupture has occurred.

The vulnerability is also linked to the properties of the pipeline steel including strength, wall thickness, resistance to fracture propagation and other factors. For some cases, such as lateral erosion, damage thresholds have been estimated based on previous work with similar pipelines. For example, the pipeline was considered to be relatively resistant to failure for unsupported lengths of up to 25 m if exposed by lateral erosion by a river; however the vulnerability to failure increases where longer spans may be exposed. Appendix A provides details on the criteria used to evaluate each individual hazard including their vulnerabilities.

It is assumed that the pipelines will be designed and constructed in general accordance with good pipeline design and construction as practiced in western Canada since the behaviour of previously constructed pipelines, including pipelines through the Coast Mountains, is part of the experience base used to assess the hazards. A further assumption was made that steel with adequate toughness to prevent fracture propagation will be used in areas subject to geohazards, similar to other recently constructed pipelines in western Canada which formed part of the experience base of the expert panel and authors.

2.11 Mitigation Factor

Mitigation ($M_{(i)}$) is a factor operating either on the vulnerability or frequency of occurrence, depending on the nature of the mitigation and is implemented in the design, construction and/or operation of the pipeline where elevated hazard levels are identified. This factor is an expression of the effects of implementing mitigation strategies in the project design that either increase the resistance of the pipeline to potential damage by a particular geohazard, or reduce the frequency of occurrence of a particular geohazard. Potential mitigation options are identified in each of the detailed geohazard process descriptions referenced later in this report.

The mitigation methods were defined for each identified geohazard occurrence. The mitigation options are preliminary and will be revised and adjusted during further more detailed investigations and design. Further review, adjustment and implementation of mitigation options is expected throughout the design, construction and operation of the pipelines as part of the ongoing hazard and risk assessment process that will occur throughout the life of the pipelines. The mitigation factors were established based on engineering judgement and previous experience of the performance of such measures on other pipelines. For locations where more than one mitigation option is chosen, the factors are multiplicative, unless there is reason to expect that this treatment is overly optimistic. Where the mitigative factors were considered not to be independent, the overall mitigation was adjusted. For example, the combined mitigation of surface water control (0.1), groundwater control (0.1) and grading (0.1) were, in some cases, assigned an overall mitigation factor of 0.01 rather than 0.001.

2.12 Considerations for the Work

The following points discuss some key considerations with respect to the work:

1. The work was based on available information including air based and ground based site reconnaissances and investigations, interpretation of available satellite and airphoto imagery, topographic mapping, published information and other unpublished information. As additional investigative work is undertaken, the assessments provided may be revised.
2. The general methods of proposed mitigation have been outlined. Detailed mitigation design will be undertaken during the detailed investigation and design phases of the Project.
3. It is likely that some of the assessments will change as additional information is received.
4. Where there is not sufficient information available, the assessments have been made using assumptions that may be conservative. For example, for rockfall hazard areas, the assumption has been made that very large blocks sufficient to cause a LoC event could fall and would impact on the pipeline in such a way as to cause an LoC event. In reality, it is possible that future work will show that the geology of a particular outcrop is not

conductive to falls of very large rock blocks, the blocks would not have sufficient impact velocity to penetrate to and puncture the pipeline, or the pipeline is not located within the run out pathway of a potential rockfall.

5. Some of the mitigation techniques may require construction methods or routing that vary from those previously filed. In some cases, routing changes may be required from a mitigation point-of-view. In other cases, variations in stream crossing methods may be required for mitigation of slope stability conditions.
6. The assessment of the hazard impacts on the pipeline system assumes that the pipe steel has adequate toughness such that fractures will not propagate.
7. Secondary events triggered as a result of an initial event have not been considered at this point since the probability of the chain of two events leading to a LoC event is relatively low. For example, a seismic event is one potential trigger for slide movements, but the hazards of such slide movements are already included and other trigger events such as extreme precipitation events would likely have a higher probability. Seismic triggers of slides will be further considered during detailed design in the event that weak materials on which failure has not occurred to date are found during further investigations.

3.0 PREVIOUS GEOHAZARD ASSESSMENT FOR THE PROJECT

An initial geohazard assessment for the Project was carried out based on Route Rev R, and was presented in the May 2010 filing in Appendix E, "Overall Geotechnical Report" in Volume 3. The initial assessment ranked various geohazards along the project route using a five by five matrix defined by estimates of likelihood of occurrence of the geohazard and consequence of occurrence. The preliminary geohazard risk assessment was qualitative and included definition of 170 individual geohazard occurrences within 13 categories. This dataset included an evaluation of the unmitigated and mitigated scenarios for pipeline design through the defined hazard impact areas.

The existing inventory of 170 geohazards was reviewed and incorporated into the present updated work. However, it should be noted that the present report work deals strictly with events with the potential for loss of containment and thus some of the geohazards in the preliminary work, such as wind erosion, do not appear in the present assessment. It is noted that future work related to geohazards may include consideration for the effects of geohazards on other project elements and geohazards that may result in damage that does not immediately involve loss of containment, such as coating damage.

The present assessment differs from the previous assessment in several key areas:

1. In many cases, hazards were defined at specific points along the pipeline in the previous assessment. For example, a debris flow might be defined as intersecting the pipeline at

a specific kilometre post. In the present study, the pipeline length affected has been defined in all cases.

2. In some cases in the previous assessment, a specific hazard was defined over a broader area of pipeline route than it actually affected. For example, the present study defines seven potential avalanche hazards along Hoult Creek, each with a specific defined length, whereas the previous study indicated that avalanche hazard was present along the entire length of the route in the Hoult Creek valley. This previous approach would overestimate the risk in the present study since the hazard (avalanches in this case) is only present in specific areas.
3. In the previous study, some hazards were lumped together where they occur at the same location. Co-location of debris flows and avulsion is an example of this. In the present study, these hazards are discussed separately, although it is noted that the mitigation methods may overlap and need to be coordinated in the design and construction of the pipeline.
4. Some additional hazard locations were added to the present study. These were not included in the previous study because they had a low potential for posing a serious threat to the pipeline. In other cases, hazards were added on the basis of additional knowledge that has been acquired during further investigations since the original assessment was compiled. In this respect, the potential for occurrence of various hazards has been reassessed along the entire pipeline using the most recently available information.
5. Some hazards have also been added in areas where the pipeline route has been significantly revised since route Rev R. In other cases, reroutes have routed the pipeline away from some hazards. These have been retained in the database but have been assigned $F_{(i)} = 0$.

4.0 GEOHAZARD ASSESSMENT PROCESS USED TO SUPPORT PIPELINE RISK ASSESSMENT

As discussed above, the geohazard assessment presented in this report was carried out from the perspective of a susceptibility assessment. A susceptibility assessment includes the consideration of the potential for occurrence and the return period, but also includes the recognition that some processes may occur without damage to pipeline (vulnerability), and that mitigation will reduce the exposure to a threat.

As defined above, susceptibility is the product of the factors for occurrence (I), frequency (F), vulnerability (V) and mitigation (M). Susceptibility to a loss of containment (FLOC) event expressed in terms of events per year at any location or segment (i) is expressed numerically as:

$$\text{Susceptibility} = F_{\text{LOC}(i)} = I_{(i)} \times F_{(i)} \times V_{(i)} \times M_{(i)}$$

A similar form of this method was used for geohazard assessment of the Mackenzie Valley Gas Pipeline Project, previously reviewed by the National Energy Board, and was accepted as a suitable approach in the NEB's Reason for Decision (National Energy Board, 2010).

The geohazard assessment work included establishing the list of geohazards along the route that could result in a potential LoC event, identification of the possible occurrence areas, definition of the unmitigated susceptibility factors at each location and definition of appropriate mitigation strategies. The assessment process is discussed further in the following sections.

4.1 Geohazard List used for Geohazard Assessment

Table 1, below, lists the geohazards considered in the current assessment. The list was developed based on the work of the Project team to date, and as noted above, is restricted to events that could potentially lead to loss of containment. Detailed descriptions of each of the geohazards are presented in Appendix A.

Table 1: List of Geohazards Assessed

Category Name	Acronym	Description
Avulsion	AVU	Channel switching or erosion of a new channel on an alluvial fan. Does not include channel changes or lateral erosion in streams not on alluvial fans.
Debris Flow	DF	A very rapid flow of saturated debris in a steep, confined channel.
Avalanche	AVA	Rapid down-slope movement of snow and ice, possibly with entrained debris. Does not include rock avalanches (note that no rock avalanche hazard was found along or close to the route).
Rockfall	RF	Direct fall and rolling rocks from rock bluffs, rock or rock cuts, and/or colluviums or soil slopes.
Slide – shallow to moderately deep	SM	Translational sliding of soil or rock with a rupture surface less than 10-15 m deep.
Deep-seated slide	DS	Translational, rotational or compound sliding of soil or rock with a rupture surface greater than 15 m deep.
Scour	SC	Erosion of particles from a stream bed to produce either temporary or permanent downcutting.
Lateral Migration	LM	The lateral movement of a stream channel as a result of erosion and undercutting of banks. Reoccupation of subchannels and channel switching in meandering or braided systems is also considered to be lateral erosion for the purposes of this study and not avulsion.
Lateral Spreading	LS	Lateral ground displacements as a result of liquefaction or weakening of loose or soft geological units as a result of seismic shaking. Includes lateral movement toward a topographic break as well as Transient Ground Deformation (TDG) that may not move toward a topographic break.

No rock topples, rock avalanches, or sackung failures that would affect the proposed route have been identified and so are not included in the foregoing list. Karst hazards were identified in the previous assessment along former version of the route; however, no karst has been identified on route Rev U.

4.2 Detailed Descriptions of Geohazards

Appendix A includes detailed ranking sheets for the geohazards outlined in Table 1. The ranking sheets summarize the basis for the susceptibility approach as well as assumptions and guidance on the assignment of the I, F, V, and M factors for site specific evaluation. Additional comments providing the rationale for choice of various factors are included in the detailed geohazard summary sheets attached in Appendix B.

4.3 Definition of Potential Geohazard Impact Areas

Using the ranking sheets in Appendix A and existing project data, the pipeline route was evaluated to determine potential geohazard impact areas. The assessment area used for the purposes of the geohazard assessment included areas beyond the nominally 1 km wide assessment corridor where potential initiation zones or run-out lengths for geohazards that could potentially impact the pipeline route warranted.

4.4 Database Management of Site Specific Data

A total of 346 geohazard occurrence locations were identified in the present study. To handle the increased amount of data, a project specific geohazard database was created. The output from the database is included in Appendix B and is described below.

Each hazard is presented in the database as a “Geohazard Detail” record. The records have a unique number (ID) for each identified hazard. The identification number does not imply location but is simply assigned in serial fashion as the data is uploaded. Note that the geohazard identifications for the original 170 geohazard occurrences in the Overall Geotechnical Report are included as the “Feature” number. These numbers are not actively used in the present data base but are included to allow correlation with the previous report. Reference information is provided which allows the user to determine the source from which the particular hazard was identified.

As discussed above, certain hazards identified at earlier stages of the Project that pertain to former revisions of the proposed route are included in the database for consistency with previously filed reports. These relict or “Legacy” records are no longer considered to have potential impacts on the current Rev U alignment since they have been mitigated by routing changes. These records have been flagged and their occurrence, frequency and vulnerability factors have been set to zero. This treatment maintains consistency with previous filing and retains the hazard for detailed consideration in case of future reroutes in the general area.

Other hazards within the database have been flagged as requiring a “Reroute” for mitigation purposes. The reroutes are relative to the current Rev U alignment but at the time of writing have not been formally accepted in the Project Routing Process (Route Committee).

5.0 RESULTS OF GEOHAZARD ANALYSES

The results of the geohazard analyses are attached in Appendix B which contains both a summary of the results and the individual description sheets for each individually identified hazard listed sequentially by Rev U kilometre post. Appendix C provides a summary of the mitigations considered for each defined geohazard.

The frequency of loss of containment is presented for each specified hazard impact location relative to the Rev U chainage. The mitigated frequency values typically ranged from 1×10^{-10} to 1×10^{-4} events/year. The statistical compilation and assembly of frequency data into an overall probability of failure for the full length of the pipeline is beyond the scope of this report.

It should be recognized that the data presented in the Appendices are conditional on the application of the proposed or equivalent mitigations. The mitigations have been selected in accordance with standard and appropriate pipeline construction practices. Note that the mitigation strategies and locations shown are preliminary and will be further considered and refined at the detailed engineering stage of the Project.

6.0 LIMITATIONS AND CLOSURE

Assessments and related information presented herein are based on a geotechnical evaluation of the work and other information noted. The results of the geohazard assessment are intended to provide baseline information to be used within the context of an overall pipeline risk assessment. It is assumed that the assessments will continue to be updated as the Project evolves. If conditions other than those reported are noted during subsequent phases of the project, AMEC should be notified and be given the opportunity to review and revise the current recommendations, if necessary. The assessments presented herein may not be valid if an adequate level of review or inspection is not provided during construction.

This report has been prepared for the exclusive use of Northern Gateway Inc and its consultants for specific application as discussed in this report. The assessments are intended to be used within the overall framework of risk assessment by persons and organizations familiar with and having suitable skills in risk assessment. Any use which a third party makes of this report, or any reliance on or decisions made based on it, are the responsibility of such third parties. AMEC accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions based on this report. It has been prepared in accordance with generally accepted geotechnical and hydrotechnical engineering practices. No other warranty, expressed or implied, is made.

Respectfully submitted,

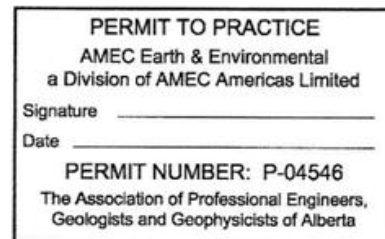
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