National Transportation Safety Board
Washington, D.C. 20594

Liquid Pipeline Accident – Marshall, Michigan

Integrity Management Group Chair's Factual Report

Accident Identification:

Location:	About 0.6 mile downstream of the Marshall, Michigan, pump station; near milepost 608.
Date:	July 25, 2010
Time:	About 5:58 p.m., Eastern Daylight Time
Product:	Crude oil
Component:	30-inch diameter transmission pipeline
Accident No.:	DCA10MP007
Group Chair:	Ravindra M. Chhatre.

Parties to the Investigation:

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Brief narrative of the Accident:

On the evening of Sunday, July 25, 2010, about 5:58 p.m.[1], a 40-foot long pipe segment in Line 6B, located approximately 0.6 of a mile downstream of the Marshall, Michigan, pump station, ruptured. The Line 6B is owned and operated by the Enbridge Energy Inc. (Enbridge). The Enbridge control center in Edmonton, Alberta Canada was in the final stages of executing a scheduled shutdown of their 30-inch diameter crude oil pipeline (Line 6B) when the rupture occurred. The initial and subsequent alarms associated with the rupture were not recognized as a line-break through two start-ups and over multiple control center shifts. Residents near the rupture site began calling the Marshall City 911 dispatch center to report odors at 9:25 p.m. on Sunday; however, no calls were placed to the Enbridge control center until 11:17 a.m. the following day. Once the Enbridge control center was notified, nearly 17 hours after the initial rupture, remote controlled valves were closed, bracketing the ruptured segment within a three-mile section.

The accident resulted in an Enbridge reported release estimate of 20,082 barrels (843,444 gallons) of crude oil with no injuries or fatalities. The rupture location is in a high consequence area[2] within a mostly rural, wet, and low-lying region. The released oil pooled into a marshy area over the rupture site before flowing 700 feet south into Talmadge Creek which ultimately carried it into the Kalamazoo River.

Line 6B was constructed in 1969 as a 293-mile long extension of the Lakehead pipeline system, stretching from Griffith, Indiana to Sarnia, Ontario, Canada. The failed segment was a cathodically protected, tape coated pipe manufactured by Italsider s.p.a.[3] per the 1968 API[4] Standard 5LX *Specification for High-Test Line Pipe* X52 specification with 0.25-inch thick wall and a double submerged arc welded (DSAW) longitudinal seam. The maximum operating pressure (MOP) for Line 6B was 624 psig; however, at the time of the accident, Marshall Station discharge pressure was limited to 523 psig due to a 2009 Enbridge imposed pressure restriction

[1] All times are expressed in local accident time, Eastern Daylight Time.
[2] As defined by PHMSA under 49CFR§195.450.
[3] Societa Per Azioni (Italian). The Italsider pipe was purchased from Siderius Inc. of New York.
[4] American Petroleum Institute, New York, New York

between Stockbridge and Sarnia. The maximum-recorded discharge pressure at Marshall, prior to the rupture, was 486 psig.

Integrity Management Rule:

The Pipeline and Hazardous Material Safety Administration's (PHMSA) Office of Pipeline Safety (OPS) amended title 49 *Code of Federal Regulation* (CFR) 195 to include pipeline integrity management (IM) in High Consequence Areas (HCA) for hazardous liquid pipeline and carbon dioxide pipeline operators with 500 or more miles of pipelines (Subpart F, Section 195.452). The regulation became effective March 31, 2001. Later, OPS extended this regulation to include operators who owned or operated less than 500 miles of hazardous liquid and carbon dioxide pipelines. The regulation became effective February 15, 2002,

Based on the comments PHMSA received by March 31, 2001, it amended the IM rule, particularly repair and mitigation provisions (§195.452(h).) in the regulation. The revised regulation became effective on May 29, 2001, except for paragraph (h), which became effective on February 13, 2002. According to the PHMSA, the API had objected to the word "repair" throughout the paragraph (h). PHMSA agreed that the word "repair" may be too narrow to cover the range of actions an operator could take to address a safety issue. PHMSA replaced the word "repair" with the word "remediate" throughout paragraph (h) in the regulation. PHMSA also stated that though it firmly believes that repair is necessary to address many anomalies, it may not be necessary in all cases. Pertinent portion of the regulation is given below:

Covered pipelines are categorized as follows:

(1) Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this part.
(2) Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this part.
(3) Category 3 includes pipelines constructed or converted after May 29, 2001.

In 49 CFR Subpart F, Section 195.452, paragraph (e) of the regulation, risk factors (that is, pipe size, material, leak history, repair history, coating type, ….) that should be considered by an operator for establishing both baseline and continued assessment schedule have been listed. The elements of integrity management program also have been listed in paragraph (f). Specifically, paragraph (f)(3) states that an operator must include, "*An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure*" in its written integrity management program

The actions an operator must take to address integrity issues in HCA are addressed in 49 CFR 195.452, paragraph (h). The regulation states, "*Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a* *potential threat to the integrity of the pipeline*" and provides special requirements for scheduling remediation. Under 180-day condition, amongst other thing, the regulation states that

> *an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:*
>
> *(G) A potential crack indication that when excavated is determined to be a crack.*
> *(H) Corrosion of or along a longitudinal seam weld.*
> *(I) A gouge or groove greater than 12.5% of nominal wall.*

Appendix C of the regulation provides guidance about "*other conditions*" that an operator should evaluate. The appendix addresses anomalies that are longitudinal in orientation and anomalies over a large area. However, the regulation does not define "a large area."

Actions that an operator must take to prevent and mitigate the consequences of a pipeline failure that could affect a HCA are addressed in 49 CFR, 195.452 (i). In the section titled, General Requirements, "*establishing shorter inspection intervals*," has been mentioned as a preventive and mitigative measure.

Enbridge Integrity Management Program for Liquid Lines:

Risk Management:

The operational risk management department at Enbridge is responsible for the development, implementation and revisions of the mainline risk assessment model.

Enbridge stated that it started risk management approach in early 1990, and a steering committee was created to identify, quantify, and prioritize hazardous to people, property and environment. The OPS in 1997 did not consider Enbridge's Lakehead facility for the risk management demonstration project, because it did not have a comprehensive integrated risk management program at that time. With the goal to develop a system-wide mainline and facility risk assessment model, the operational risk management (ORM) program at Enbridge was started in 1999, and the operational risk management advisory committee (ORMAC) was created. According to Enbridge the intent was to develop a comprehensive and integrated approach to risk identification, assessment, and control. It was expected that amongst other things, the ORM program would help operational districts to identify risk drivers on their facilities and provide Enbridge management an enhanced understanding of the relative risk profiles of pipeline segments and facilities.

Mainline risk assessment working group consisting of subject matter experts within Enbridge was established in late 1999 and was tasked, amongst other things, to define a pipeline risk model using an indexed approach, and to develop the data gathering process.

Risk assessment model pilot tests on Line 3 from Bethune to Strome and on Line 6A from Dundee to Griffith were completed in late 2000, and efforts to implement the model system-wide were started in January 2001. An OPS audit was conducted in May and June 2003. Audit findings and their resolution, were provided to the NTSB by Enbridge. The OPS believed that in general, the IM was the place to bring all elements of the Enbridge integrity management programs together, and noted as one of the audit findings that integration of information/risk analysis results did not appear to have a central role in the overall evaluation of integrity challenges. Enbridge acknowledged that the OPS was correct in pointing out this deficiency, and stated amongst other thing that "*Studies have been initiated in 2006 to see a) how CP data can be better included and b) how the risk assessment results and denting data can be used to request additional geometry ILI runs.*" To give consideration to cumulative effect of other multiple threats during risk analysis was not mentioned.

PMHSA conducted a comprehensive audit of Enbridge liquid pipeline system in June 2006. Their audit findings and their resolution were provided to the NTSB by Enbridge. In one of the audit findings, PMHSA noted a "*Lack of a requirement to verify that all information is up to date prior to use in the risk assessment model.*" PMHSA felt that it was important for the risk model to consider most current data. In response, Enbridge stated that it is initiating a process that would record the accuracy and completeness of the data. PMHSA also noted that Enbridge lacked clear decision basis to determine which general preventive and mitigation measures should be implemented, and quoted "impact on risk" as one example. In response Enbridge stated that a decision making process was under development. Information clearly showing whether such processes were developed and were in effect at the time of the accident was not provided by Enbridge. The PMHSA also noted that Enbridge lacked "*a formalized periodic evaluation process- that includes all rule-required evaluation factors.*" Enbridge responded that "*Starting in the fall of 2007, Operational Risk Management and Pipeline Integrity will meet to discuss / share the results of the mainline risk assessment and integrity related assessments.*" Documentation clearly showing when such a process was developed and implemented, how often the two groups met and what was discussed prior to the accident, were not provided by Enbridge.

The operational risk management organization that existed at the time of the accident was supported by five groups (mainline risk assessment model working group, facility risk assessment model working group, process hazard assessment (PHA) steering committee, top risk areas committee, region/department contacts) which supported operational risk mgmt supervisor. Individual group members belong to different units within Enbridge and were assigned by their respective supervisors. During 2004-2005, the mainline risk assessment model working group, facility risk assessment model working group, and region / department contacts supported the operational risk management supervisor.

The mainline risk assessment model involved risk analysis and risk evaluation. Risk analysis involved threat likelihood and consequences (that is, Risk = Threat Likelihood x Consequence). Enbridge believes that this risk management approach would allow Enbridge to pursue those projects or activities that accomplish cost effective risk control. The consequence part of the equation included three components: impact on customers, impact on environment, and impact on population. These components were given values of 20, 30 and 50 percent respectively. Starting in 2004, likelihood of various threats, such as internal and external corrosion, stress corrosion cracking, fatigue cracking, ground movement, etc., were assigned percentages based on working group discussion, and other available information. In 2008, the likelihood factors values were based on Enbridge failure frequency (70 percent) and industry failure information (30 percent). With this information, the risk management group gave risk scores to different pipe segments. In November 2009, there were 58,513 sections of 1,000 feet each that were ranked in this manner. The 1,000-foot long section containing the ruptured pipe joint was ranked 1750.

According to the supervisor of risk management modeling group, the index model that Enbridge was using prior to the Marshall rupture had limitations. The model was not very useful in giving a risk acceptance criterion, and he believed that it was due to limitation of the index modeling methodology in general. He further stated that so far the regions have made very limited use of risk model results. Whether to implement any risk mitigation project or not was the responsibility of regional or department management. If the regions want, they can act on the information provided by the risk management (that is, improve maintenance) or if they want, they may decide to do nothing. He also stated that the pipeline integrity group does their own quantitative risk assessment of pipeline sections, and that risk management modeling group/the risk assessment group does not provide direct input in that process.

The director of integrity stated that around 2001, the pipeline integrity group had an established approach to decide re-inspection intervals and tool selection, and the results of the risk model were "nominally" utilized to support inspection planning in high consequence area. Enbridge stated that around 2005, the consequence information generated from the risk model was used to reduce the pipeline inspection interval by up to 1 year for some segments. No documentation was provided by Enbridge showing if and how the critical information from ILI findings (e.g., locations requiring immediate action) was immediately related to risk management modeling group prior to the rupture.

Integrity Management:

In 2004, the Enbridge pipeline system in the United States consisted of 13 individual pipelines with a total of approximately 3,883 miles of pipe. From its inception in 2005, the Enbridge pipeline integrity department has been responsible for monitoring and mitigating activities that are pertinent to mainline pipelines. The department is responsible for evaluating the risks associated with metal loss, cracks, geometry-related issues and determining the appropriate inspection timeline for each pipeline segment. Enbridge claims that it has had a dedicated group with similar responsibilities since late 1980. The focus of the pipeline integrity program has been to prevent failures resulting from operation-related damage caused by various factors (including corrosion and cracks). Enbridge stated that it monitored its pipelines to determine the nature and extent of the damage. If damage was detected, Enbridge stated that "*the pipeline condition is restored so that a constant-base integrity level is preserved.*"

Enbridge applies a fitness-for-purpose approach as a principal methodology to manage integrity of its pipelines. The pipeline integrity program's goals are: prevention, identification and managing defect growth, and the timely repair of defects in pipelines. The integrity department has several internal groups: materials technology, integrity programs, technical services and integrity analysis.

The materials technology activities included defect assessment, fracture mechanics, failure investigation, steel properties, non-destructive testing, and welding. The integrity programs activities included excavation and repair, In-Line inspection (ILI), internal corrosion mitigation and station piping integrity. The integrity analysis activities included integrity science (that is, cathodic protection, coating), data management and trending, risk assessment, process audits and improvements.

Enbridge stated that

The types of damage that deteriorate the fitness of the pipeline system over time, and are managed through planned programs by the pipeline integrity department, fall into one or more of the following categories:

- *Metal loss such as corrosion or gouging.*
- *Pipe deformation such as denting.*
- *Cracking related to steel manufacturing or forming processes.*
- *Cracking related to exposure to the operating or natural environments.*
- *Combination of the above items.*

Internal and External Corrosion Management:

Internal corrosion control guidelines provide methodology and core activities to manage internal corrosion of Enbridge pipelines. Enbridge evaluated internal corrosion susceptibility by integrating and evaluating data on: pipeline characteristics, ILI data, operating conditions, pipeline cleanliness, crude and sludge sampling and historical leak data. Use of appropriate cleaning pigs, biocide, and inhibitors were listed as mitigation methods in the guidelines. In 1996, Enbridge began a chemical inhibition program to prevent internal corrosion of Line 6B by using a two-phase inhibitor. The NTSB's Materials Laboratory investigation found no significant internal corrosion in the ruptured pipe joint.

According to Enbridge, Line 6B was coated with field-applied Polyken number 960 tape coating and the application was done by machine. The coating had a 9-mil[5] thick polyethylene (PE) backing and a 4-mil thick synthetic rubber/synthetic resin adhesive; and tape overlap was 0.5 and 1 inch respectively. Enbridge believed that the type of external coating broadly determines the potential susceptibility to SCC. Since Line 6B utilized a PE tape coating Enbridge considered it susceptible to SCC.

Also, Line 6B was under impressed current cathodic protection system. Close-interval survey was conducted by an outside contractor after the accident. The contracted reported that pipe to soil potentials data collected over the top of the pipeline in the vicinity of rupture indicated acceptable level of cathodic protection.

[5] 1mil=1/1,000 inch

Enbridge provided a procedure to establish corrosion growth rates and associated re-inspection intervals. This undated document did not identify who prepared or approved it, nor had an effective date. According to Enbridge, this document was not in effect at the time of the accident. Enbridge stated that subsequent documents were dated and approved.

The earlier approach mentioned in this undated document was to assume linear growth and use maximum corrosion rate from the available information. According to the procedure,

> *The inspection interval was based on the time for a corrosion feature to grow from a depth of 50% to 80% wall thickness assuming a corrosion growth rate double the maximum estimated. The rationale was that following an in-line inspection (ILI), all external corrosion features with a depth of 50% or greater would be excavated. Based on depth alone, all features in the field with a depth of 80% wall thickness or greater would be repaired. In order to account for the effect of length and depth, not considered by this approach, the inspection interval was conservatively defined as half of the calculated time period.*

According to this document, Enbridge's inspection interval was tied directly to results of the most recent ILI run and the excavation program associated with it. The procedure states:

> *…if excavation results (Field Metrics) show one or more defects with a Rupture Pressure Ratio[6] (RPR) <0.8 and/or external corrosion greater than 80% of pipe wall thickness and/or internal corrosion greater than 50% of pipe wall thickness, the corrosion growth rate from which the last inspection interval was derived is interpreted to be more aggressive than projected and the subsequent inspection interval for that segment could be shortened to accommodate this higher growth rate. In general, the subsequent revalidation interval will be reduced by one year.*

Enbridge stated that according to July 7, 2007, procedures it determines corrosion re-assessment intervals using up to three complimentary processes: subject matter expert metric review, deterministic growth and probabilistic based analysis. For non-HCA areas, defects are targeted either for repair or re-assessment in half the time it would require them to reach the tolerance level; whereas for HCA, features are targeted either for repair or re-assessment in one third the time it would require them to reach the tolerance level. Enbridge stated that several revisions to the document were made since 2007 until 2010 which were dated and approved.

Defect evaluation and repair procedures 06-02-02 dated December 19, 2005 and April 1, 2006, in Enbridge's Operation and Maintenance (O&M) procedures provide guidance for repairing cracks. These procedures stated that "*surface cracks are considered defects and must be removed by grinding and then evaluated*." In a footnote, the procedure mentioned that defect depth should include crack depth and the wall loss. The procedure also stated that "*crack-like indications are considered defects unless an Engineering Critical Assessment (ECA) determines*

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[6] Enbridge defines Rupture Pressure Ratio (RPR) as:
RPR = predicted defect failure pressure / pressure at 100% specified minimum yield strength (SMYS) of the pipeline. An RPR value of 1.0 equates to 100% of SMYS

that they are acceptable." Though the procedure identified "cracks" and "crack-like indications" as different features, the procedure did not elaborate difference between them.

Corrosion Excavation Program:

Enbridge's 2009 excavation program criterion is to excavate any features in excess of 50% wall thickness loss or with a Rupture Pressure Ratio (RPR) of less than one. During a March 26, 2012, phone conversation, Enbridge stated that the same criteria existed from 2004 through 2007.

The procedure PI-03 to develop a final dig list dated April 12, 2006, was provided by Enbridge. The materials technology engineer and integrity analysis engineer are responsible to develop a list of features to be excavated from the crack ILI and corrosion ILI data respectively. The final list includes all features that meet the Enbridge excavation criteria that have not been excavated, assessed and repaired in the past. Enbridge considers the day the final dig list is approved as the date of discovery.[7] From the final dig list Enbridge would decide if there is a need for pressure restrictions.

The procedures and guidelines for non-destructive examination of excavated mainline pipelines were provided by Enbridge. This unapproved document, dated 2005, covers instructions for internal and external corrosion damage, excavations, dent and geometric anomaly excavations and crack anomaly excavations. One of the instructions to a non-destructive examination technician looking for external corrosion damage states: "*If the nominal wall thickness indicated on the Dig Package is different than the nominal wall thickness for that joint as found in the ditch, contact Pipeline Integrity to confirm the appropriate nominal thickness to use at that location.*" Enbridge supplied no documentation showing that the materials engineer and integrity analysis engineer were required to compare the wall thickness data reported by the vendor after an ILI inspection with the nominal wall thickness for various pipe joints during his/her analysis, and when preparing the dig list. According to this procedure, for any corrosion or crack feature, if the rupture pressure ratio (RPR) is less than 1.0, Enbridge would establish pressure restrictions to establish the design safety factor.

According to Enbridge procedures for any features requiring immediate repair, a pressure restriction would be taken. For corrosion feature the pressure restriction would be according to ASME/ANSI B31.4, for geometry feature the pressure restriction would be 80 percent of the highest pressure that had been experienced at that location within the past 3 months. For a crack feature the pressure restriction would be based on a remaining strength calculation in order to maintain a safety factor of 1.25. The MOP was 624 psig for rupture segment. The procedure further stated that

> *In cases where multiple features (i.e. corrosion or cracking in a dent) or unusual features are present, the Excavation Program Coordinator will complete an Engineering Assessment to determine whether additional restrictions are required*

[7] Part 192.452 states: "*Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. –* "

to safeguard pipeline facilities, and if so, what restrictions are appropriate. Some of the factors or options to consider include:

- *Behaviour and shape of the defect (i.e. sharp dents)*
- *NG18 or CorLAS Crack Calculations*
- *Potential multiple defects such as cracks inside corrosion and the proximity of the defects to sensitive areas along the ROW.*

The procedure also provides detail guidelines for assessment and field reporting. No formal procedure that described if and how to share this information with other groups, such as crack management, crack excavation, or risk analysis groups was provided. Enbridge provided the 2007 and 2009 ILI data to NTSB. The data shows that there were 594 entries (that is, locations). Of these, 488 entries had an RPR value of less than or equal to 1.0, and many had an RPR value of less than 1. For corrosion features, a total of 185 excavations were performed: 14 excavations were performed in 2009 and 164 excavations were performed in 2010. Enbridge stated that this was related to the report re-issue that occurred following the 2007 inline inspection of line 6B.

Crack Management:

The hazardous liquid transmission pipelines that Enbridge owned/operated were constructed between 1950 and 2010 using steel pipe. At the time of the accident, Enbridge was aware that these pipelines are susceptible to time-dependent cracking depending upon type of coating, operating conditions and environment. As stated earlier, Enbridge believed that since Line 6B utilized a PE tape coating it was susceptible to SCC.

Enbridge's crack management plan focused on fatigue and stress corrosion cracking (SCC) and "*expected*" that the procedure would be applicable to other mechanisms, such as corrosion fatigue. The materials technology group was responsible for crack management, and the plan included engineering assessment, pipeline monitoring, mitigative repairs, and preventive activities. Pipeline monitoring for cracks involved ILI, direct assessment, and Fitness for Service[8] assessment techniques.

Enbridge was utilizing BMT Fleet Technology (BMT) software, which utilized industry-standard equations to analyze the pressure data, determining the predicted failure pressure of a defect, and predicted the expected life of a crack. According to the company brochure, the BMT flaw assessment tool, FlawCheck, was developed to support integrity programs for metallic structures and determines the potential for failure due to the presence of flaws in steels. Also, the tool utilizes loading data for fatigue analysis. The fracture mechanics approach given in British standard BS 7910 and American standard API 579 was used to calculate fatigue crack growth. RainFlow[9] analysis of operating pressure data, material properties, and Paris Law[10] constant are used in fatigue analysis.

8 Fitness-for-Purpose and Fitness for Service terminologies have been used interchangeably, representing engineering assessments which calculate the adequacy of the structure for continued service under current conditions.

9 RainFlow is a method of counting cycles in a random load history. (see ASTM E 1049)

Enbridge also evaluated operating pressure data to determine the pipe pressure loading rate. This information was used in determining the likelihood of SCC growth. Fatigue analysis and a pressure loading rate analysis are used to determine susceptibility to cracking, and results are used in mitigative activity.

Crack Management Excavation Program

The length, orientation, and radial depth information for various features obtained from ILI data are used to determine if an excavation is needed to further evaluate the feature by using a Fitness-for-Purpose method. For cracks, each defect that is predicted to fail below the hydro-test pressure is selected for excavation and assessment. Field personnel were required to contact the excavation coordinator if there was a gouge in or near the dent, or if there was cracking in or near the dent.

Either NG-18 log-secant formulae[11] or the CorLAS[12] techniques are used to determine Fitness-for-Purpose. The analysis identifies all features that would result in failure if the line was to be pressure tested at 1.25 times the maximum operating pressure (MOP) of the line. The features are evaluated in the field to accurately determine the length and depth of the features. These data are shared with the vendor and are compared to the ILI data to obtain unity plots.

To determine the degree of pressure cycling experienced by pipeline segments Enbridge had developed an automated pressure cycling analysis tool and stated that

> *The pressure cycling analysis is completed on a monthly basis. Discharge pressure data from the previous month for the given pipeline segment is fed through the analysis routine to generate a predicted fatigue life (using BS7910 failure criteria, pure fatigue failure). The fatigue analysis assumes a starting flaw length of 2a = 6 inches, and starting flaw depth of 20% wall thickness.*

The operating pressure data are utilized to determine fatigue life of segments and are used to determine if a re-inspection is needed. Enbridge stated that *"This analysis is completed on a quarterly basis to ensure that operating pressure trends are captured on a timely basis and modifications to ILI planning can be made as necessary.*" No formal process requiring using information or data from other groups, or sharing this information with other groups such as risk management (except on an annual basis), was noticed.

Enbridge provided its 2005 crack tool ILI data to the NTSB. The data shows that a total of 929 crack-like features were identified, of which 64 were excavated. Of these 64 features, 23 had calculated rupture pressure that was less than hydro-test pressure. Of the 929 total crack-like

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[10] Paris-Erdogan law: The relationship between stress intensity factor and crack growth rate assumed BMT Fleet Technology analysis is defined as: da/dN = C (ΔK) m where C and m are material specific constants.

[11] Log-secant formulae: According to some research paper authors, the NG-18 LnSecant methods are considered very conservative, particularly, for fatigue life predictions. However application of this method to SCC predictions of failure pressure and critical (flaw) size could be non-conservative due to the use of overly estimated fracture toughness values for the assessment.

[12] CorLAS is a tool/software developed by CC Technologies Systems, Inc

features that were identified, 61 features had calculated rupture pressure less than pressure at 100 percent SMYS, but only 29 features had calculated rupture pressure less than hydro-test pressure. The ruptured pipe joint had 6 crack-like indications, but their calculated rupture pressure was more than hydro-test pressure and the joint was not excavated. The calculated rupture pressure to hydro-test pressure ratio for the 51.6 inch-long feature in the rupture pipe joint was 1.077; whereas for the same feature, calculated rupture pressure to pressure at100 percent SMYS ratio was 0.99. This feature was not excavated.

Also, for two locations in the rupture area, at the NTSB's request, Enbridge ran fitness for purpose calculations using ILI tool data for: (1) corrosion (wall loss) plus minimum and maximum crack depths, and (2) corrosion (wall loss) plus minimum and maximum crack depths and one tool tolerance. Next day, after performing the calculations, Enbridge stated amongst other things, that Enbridge believes that "*Simply adding the maximum ILI reported depths plus additional generically specified tool tolerances is inappropriate and not a recommended approach (by Enbridge) to establish an accurate crack depth estimate. Instead, adding depths based upon calibrated information using detailed field NDE results from Integrity digs is recommended. Such calibrated results should also include engineering based conservatism.*" However, the data provided by Enbridge and PII (Attachment–I, Tables I and II) indicated that in all cases, including when minimum crack depths with wall loss, were used without tool tolerance, predicted rupture pressure was below both, the hydro-test pressure and pressure at 100 percent SYMS.

Stress Corrosion Cracking:

The stress corrosion cracking (SCC) program is part of Enbridge's overall crack management program and Pipeline Integrity has been responsible to develop the plan. About 39 percent of the Enbridge pipeline system is considered to have susceptibility to SCC. Of the 39 percent, about 90 percent has higher susceptibility to SCC.

Enbridge was a member of the Canadian Energy Pipeline Association (CEPA), and participated in the development of a basic framework for a SCC management program and had adopted the CEPA framework (discussed later) as the basis for the Enbridge SCC management program system wide. The program's primary focus was directed to selecting excavations based on ILI results.

As a policy, Enbridge examined all excavated sites for SCC regardless of the intent, and utilized the definition of "significant" SCC that has been adopted in the CEPA's "Stress Corrosion Cracking Recommended Practices." For the discovery of "significant" SCC the pipeline integrity department was responsible to establish the reporting requirements to the National Energy Board (NEB) of Canada. There is no reporting requirement to PHMSA under Part 195-452. If the severity SCC found was deemed not to be "significant", then Enbridge's policy was to conduct periodic monitoring. Long term measures to mitigate SCC were reviewed annually.

In an undated Enbridge document on SCC management program that was in effect in 2005, it was stated that "*If SCC is found and the severity is deemed to be "significant", a* *thorough analysis of the characteristics pertaining to the site where the SCC was found will be performed. Similar locations along the pipeline or pipeline segment can then be identified for potential additional excavations or periodic monitoring*."

According to Enbridge, all crack-field features 2.5 inches or longer, were scheduled for excavation. Enbridge used CorLAS program to evaluate integrity/rupture pressure and to make remaining life prediction when evaluating the observed SCC in Line 6B. The software uses flow strength failure criteria for estimating the residual strength of the corroded pipe; and either inelastic fracture toughness or flow strength criteria are used for estimating the residual strength when cracks are present in the pipe steel.

In-Line Inspections:

In-line inspection tools and technology are typically used to measure the size and location of defects. Depending upon the technology, ILI tools can detect and size nature and extent of damage caused by corrosion, cracks, dents, gouges etc., and may identify if the defect is present on the internal or external surface of the pipe. Verification digs (excavations) are typically performed to build confidence in the ILI data and/or to take remedial actions to ensure integrity of the pipeline. Though subsequent in-line inspections may yield information about defect growth, the detection capability of the ILI tools is somewhat limited by the probability of detection and identification. In one of the responses to NTSB, Enbridge stated: "*Throughout industry, ILI using appropriate technology and processes has been shown to be more effective than hydrostatic testing at maintaining a reliable pipeline*." CEPA has made no such distinction in its 1997 "Stress Corrosion Cracking Recommended Practices" document. CEPA's recommended SCC mitigation approach included hydrostatic retesting, in-line inspection if appropriate tools are available, extensive pipe replacement, and re-coating. According to CEPA, hydrostatic retesting has been shown to be an effective means for removing near-critical axial defects, such as SCC, from natural gas and hazardous liquid pipelines.

Metal loss tools are typically used to detect wall loss in the pipeline. In magnetic flux leakage (MFL) techniques, pipe wall is magnetized, and damage due to corrosion (pitting, general corrosion) results in magnetic flux leakage. In ultrasonic wall measurement technique, sound echo is used to measure the remaining wall thickness.

Crack detection tools are used to detect longitudinal defects (cracks) in the pipe wall. Ultrasonic crack detection tool uses reflected ultrasonic signal from the pipe wall to detect cracks. The tool requires liquid coupling. Transverse magnetic flux leakage tool is useful in detecting defects (crack, corrosion) in the longitudinal seams. Elastic wave tool works by sending ultrasound in two directions along the pipeline and is useful in detecting longitudinal defects.

Geometry tools, such as caliper or deformation tools, are used to find dents (that is, damage caused during the construction or by the third party) in the pipeline. Typically, cleaning pigs and geometry tools are run first before metal loss or crack detection ILI are performed.

Enbridge has been conducting various In-Line-Inspections (ILI) of Line 6B since 1976. Attachment II lists various inspections that were performed on Line 6B since 1976. Enbridge stated that it is engaged in a long-term service agreement with PII Pipeline solutions (PII), a GE Oil & Gas and Al Shaheen joint venture, to supply inspection tools and service and further stated that when needed, Enbridge has used services from other vendors.

The tools and technology used in inspecting Line 6B were provided by PII and are summarized below:

Magnetic Flux Leakage Tool (MFL):

This high resolution MFL tool can detect any metal loss feature that has a depth greater than10% of the pipeline wall thickness (WT) and minimum length and width of 0.276”x 0.276” respectively.

For pitting corrosion the tool detection limits are:

Minimum surface area of 0.276” x 0.276”	Minimum depth detected 20% WT
Sizing +/- 10% WT (at 80% confidence level)	Length accuracy +/- 0.393”

For general corrosion the tool detection limits are:

Surface area > (4 times WT x 4 times WT)”	Minimum depth detected 10% WT
Sizing +/- 10% WT (at 80% confidence level)	Length accuracy +/- 0.787”

For gouging damage the tool detection limits are:

Minimum surface width of 0.276”	Minimum depth detected 20% WT
Sizing +/- 10% WT (at 80% confidence level)	Length accuracy +/- 0.787”

Maximum WT for full specification is 0.82”

Ultrasonic Wall Measurement Tool (USWM):

This metal loss inspection tool requires a liquid coupling of the ultrasound sensors and the inner pipe wall to allow sound waves to pass between the tool and the pipeline. The speed of the sound returning allows a measurement of both internal and external corrosion. It also has the added benefit of being able to detect and measure any mid pipe wall defects such as inclusions and laminations in the steel itself. A USWM tool can detect any metal loss feature that has a depth greater than (1mm) 0.0393” and minimum length and width of (20mm) 0.787”.
For pitting and channeling corrosion, the tool detection limits are:

Minimum surface area of 0.787” diameter	Minimum depth detected 0.0393”
Sizing +/- (0.5mm) 0.0197” (at 80% confidence level)	Length accuracy +/- 0.393”

General Corrosion the tool detection limits are:

Surface area > (4 times WT x 4 times WT)”	Minimum depth detected 0.0393”
Sizing +/- (0.5mm) 0.0197” (at 80% confidence level)	Length accuracy +/- 0.393”

Maximum WT for full specification is 0.866”

Ultrasonic Crack Detection Tool (USCD):

This tool is designed to detect, locate and size, axially aligned cracks in liquid pipelines, as it requires a liquid coupling between the ultrasound sensors and the inner pipe wall to allow sound waves to pass between the tool and the pipeline. The amplitude of the sound returning at 45 degrees allows estimation of the depth of a crack or cracks in the pipeline. A crack must be both greater than 1.18" long and deeper than 0.0393" (30 mm x 1 mm) to be detected by the tool and included in inspection report. The tool reports single (crack-like) and multiple cracks (crack fields) that are axially aligned; both in the body of the pipe and the seam weld area.

The sizing in 2005 was supplied in depth range buckets as follows:

0% - 12.5%, 12.5% - 25%, 25% - 40%, >40% wall thickness (WT)

Tolerance of Sizing +/- (0.5mm) 0.02" of the minimum and maximum bucket value. **"***PII no longer reports sizing in depth range buckets i.e. percent wall thickness, but reports as actual depth in mm or inches +/- (0.5mm) 0.02." Maximum WT for full specification is 0.866.*"
The tool can detect and report the following defect types[13] :

Crack Like –	Single individual cracks in a given orientation
Crack Fields –	Multiple cracks in a given orientation
Notch Like –	Manufactured or construction damage
Inclusion like –	Mid wall inclusion or laminations
Irrelevant –	Reflectors of known none injurious features
Non decidable –	Reflectors that do not fall in any of the above categories

Regarding the presence of cracks in corroded areas of the pipe, PII stated that: "*For significant perpendicular cracks (above detection threshold) in shallow corrosion, detection and identification would be distinctive and based on the reflected echo – see figure 1 below. The estimated depth would relate to the cracking indications only, not the depth of the metal loss. It is therefore important to note the metal loss depth should be combined to the crack estimated depth in order to establish the estimated extent of the crack. Consideration of the pipeline wall thickness, ILI tool tolerances and the appropriate engineering analysis guidelines should be used when evaluating such Complex features"* (Note: When asked, PII stated that this information was not mentioned in their brochures or was not explicitly given to Enbridge. Enbridge told NTSB that it disagrees with PII's last statement and stated that "*an operator should consider both the corrosion and crack features reported from ILI inspection tools.*" However, Enbridge's 2005 and 2006 procedures, 06-02-02 do state that defect depth should include crack depth plus wall loss when conducting direct assessments of the features in the field to make repair decisions.)

[13] PII stated 4/1/2012 e-mail that in 2005 inspection metal loss was also reported. *Indications caused by metal loss – Similar reflectors to SCC caused by surface roughness from corrosion or low level SCC (below reporting spec.)*

PII further stated that

Shallow crack fields (below detection threshold) and corrosion could diffuse the ultrasonic signal and therefore reflect more or less identical signals with low amplitude and cannot be discriminated.

In order to ensure consistency in the analysis, these features are classified as crack fields; the previously used 'Metal Loss' classification in USCD data has been discontinued.

<u>Impact on performance</u>

- *POD – Signals reflected by corrosion could be diffused and overlaid on the signals of shallow cracks.*
- *POI – Weak signals could be identified as rough surface and therefore not sized and reported.*
- *Depth Estimation – The sizing performance could be affected by diffused and overlaid signals of the corrosion.*
- *Integrity assessments – When evaluation a crack in shallow external corrosion without any excavation results, and only utilizing ILI data, then the respective tolerances of both the ILI tools, wall loss and cracking must be taken into account.*

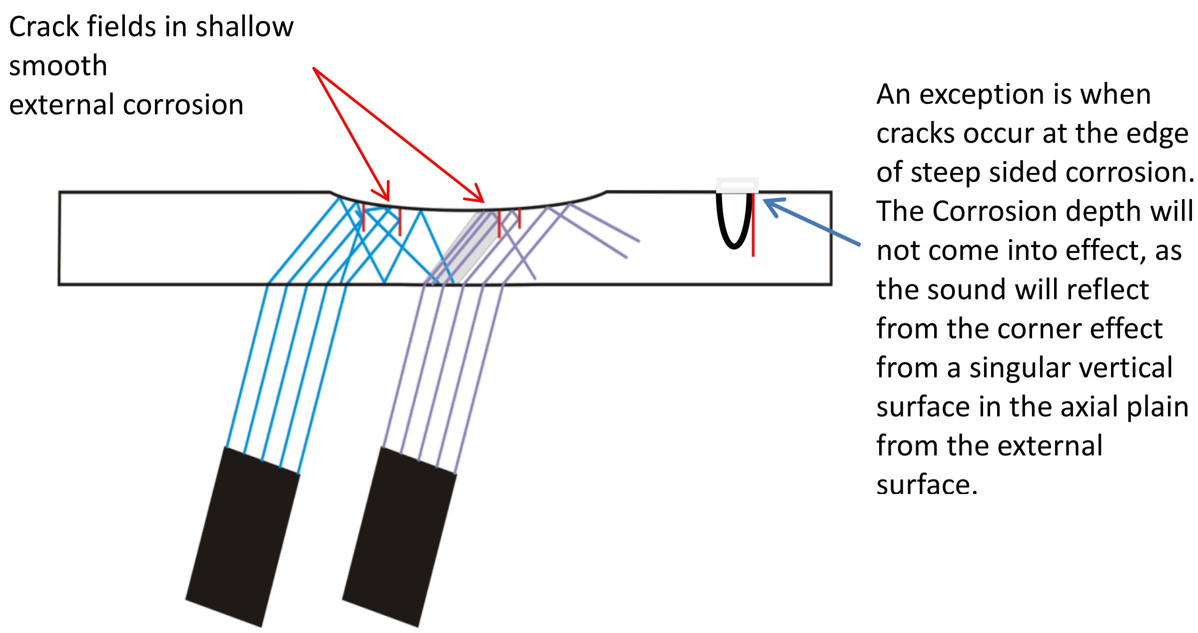

Figure 1: A schematic provided by PII showing external cracks in corrosion

Summary of Line 6B In-Line Inspections by PII:

In November 1994, a MFL inspection of the entire 294 miles of Line 6B, from Griffith to Sarnia was conducted. A report was issued in April 1995.

Starting in October 1999 and completing in November 2000, an inspection of Line 6B was conducted in two steps using USWM tool. Initial report was issued in May 2000, and a revised report was issued in July 2003. The ILI data showed external metal loss between 47 to 55 mills deep; by 1.1 to 11.5 inches long by 0.2 to 0.5 inches wide in the ruptured pipe joint. According to PII, the revision was necessary to correct characterization discrepancies between internal and external metal loss. But the data for the external metal loss features on the failure pipe joint did not change as a result of this revision.

In February 2004, an inspection of entire Line 6B from Griffith to Sarnia was conducted using USWM tool. Initial report was issued by PII in May 2004, and Enbridge received it in June 2004; and a first revised report was issued in June 2004. This revision was made to correct the above ground reference location marker listing. No changes to the metal loss features were made, therefore the feature data for the ruptured pipe joint did not change. The second revised report was issued on May 30, 2008, after the June through October, 2007 MFL inspection, and included pertinent information from the 2007 MFL report. This revision was made at the request of Enbridge to confirm or correct the number and locations of full circumferential containment sleeve repairs made by Enbridge. These features that had already been repaired were removed from the integrity evaluation (RPR) listing and the repairs information was included in the pipeline listing. Another revision to the report was made on September 15, 2008. This final report contains corrections to the nominal wall thickness values. As a result of this revision, the remaining wall thickness numbers of the reported features in the ruptured joint (GW 217720) did not change.

In September 2005, an USCD inspection was conducted, but it failed because of incorrect tool parameter programming. The test was conducted again in two runs - October 2005, and December 2005. After the recorded data was analyzed, a report that included the crack features list was submitted to Enbridge Pipelines in March 2006. A total of 6 indications were noticed in the rupture pipe joint. According to PII, initially these indications were classified as "crack field" by the analyst, but were identified as "crack-like" indications in the report submitted to Enbridge, for consistency.

In June through October 2007, an MFL inspection of the entire Line 6B was conducted. A final report was issued in November 2008, and received by Enbridge in December 2008. When PII compared the inspection tool odometer distance to the above ground marker (AGM) distance, PII noticed that in the second half of the ILI run the tool was reporting consistently and significantly shorter inline distance than the distance between the AGM's. After the appropriate corrections to the lengths of the reported features due to the tool odometer wheel slippage were made, a revised final report was issued on in May 2009.

PII stated that "*corrections to the length of the features (occurred) after GW 235350. This did not affect the reported features in the failure pipe joint GW 217720, as this is located in the* *first half of the pipeline, and was inspected prior to the odometer wheel slippage problems occurring.*" As a result of this inspection, Enbridge decided to pursue an alternate repair strategy that included pipe repair or replacement. To support this strategy Enbridge sent a long-term pressure reduction notification to PHMSA on July 15, 2010.

In June 2009, an inspection of the entire Line 6B was conducted using USWM tool. A report was issued by PII in November 2009, and received by Enbridge in December 2009. After PII debugged their "river bottom profile software," the river bottom profiles were corrected and a revised report was issued in May 2010, and was received by Enbridge in June 2010According to PII, *The program (river bottom profile software) generates the shape of the metal loss in terms of its remaining wall thickness along the axial length of a metal loss feature.*" As a result of this correction, the Rupture Pressure Ratio (RPR) of the corrosion feature in the ruptured pipe joint associated with the long seam at a relative distance 28.2 feet downstream of the reference girth weld 217720, changed from 1.067 to 1.056. The maximum depth remained at 27% and the axial length remained at 68.03 inches.

In July 2010, an inspection of Line 6B from Griffith (MP 465.58) to Stockbridge (MP 650.58) was being conducted using USCD tool. However, because of the Line 6B rupture the inspection was not completed.

The 1999 and 2004 through 2007 ILI data for the ruptured pipe joint are presented in Attachment – III, Tables IV and V and are summarized in Attachment – IV, Figures 4 -7. The data shows many areas of overlap for corrosion and cracking in the ruptured segment.

Pipeline and Hazardous Material Safety Administration

Regulatory oversight for the nation's pipeline transportation system is provided by the Pipeline and Hazardous Material Safety Administration (PHMSA), within the U.S. Department of Transportation (DOT). As one of ten agencies within DOT, PHMSA was created under the Norman Y. Mineta Research and Special Programs Improvement Act (P.L. 108-426) of 2004, which was signed into law by President Bush on November 20, 2004. The creation of PHMSA provides the Department a modal administration focused solely on its pipeline and hazardous materials transportation programs. Through PHMSA, the Department develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.3 million mile pipeline transportation system, and the nearly 1 million daily shipments of hazardous materials by land, sea, and air.

PHMSA's Office of Pipeline Safety (OPS), administers the Department's national regulatory program to assure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline. OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Since 1986, the entire pipeline safety program has been funded by a user fee assessed on a per-mile basis on each pipeline operator OPS regulates.

PHMSA – NTSB Meeting Summary:

On March 15, 2012, NTSB staff met with PHMSA representatives to discuss regulations covering hazardous liquid pipelines, particularly Part 195.452. During the meeting, the Director of Engineering and Research Division stated that under paragraph (h), sub paragraph (4) (iii) (G), PHMSA expects that all cracks are excavated. He further stated that "*integration of all threats*" in paragraph (f), sub paragraph (3) means that all threats are evaluated using an overlay or side-by-side analysis that would include cathodic protection, coating surveys, ILI tool findings, (e.g., geometry, crack, corrosion), previous dig reports, etc. He expected inspectors to look for this (during the inspection) to make sure that operators are doing this.

During the discussion PHMSA also mentioned that though regulation does not specifically mention it, operators need to perform some analysis of the crack features that are discovered on the pipeline so that segments can be prioritized for excavation.

Past Integrity Management Audits/Inspections:

PHMSA has developed an inspection process to periodically evaluate the adequacy and effectiveness of the procedures and programs that pipeline operators are required to implement. With respect to the integrity management regulations the PHMSA staff from the Central and Eastern Regions conducted an Integrity Management Segment Identification and Completeness Check of Enbridge Energy's integrity management program on February 26 - 27, 2002. The audit found deficiencies in the process Enbridge was using to identify segments that could affect high consequence areas. The PHMSA issued a Notice of Amendment (NOA) to Enbridge on May 15, 2002. Enbridge, in their final response of September 3, 2002, Enbridge agreed to modify their segment identification plan.

The first comprehensive integrity management inspection of Enbridge was conducted during the weeks of May 12 and June 2, 2003. This inspection utilizes an inspection format where the regulatory requirements are evaluated in the context of a detailed inspection protocol, in an effort to ensure a thorough and consistent review is performed on all pipeline operators. As a result of this inspection, OPS issued CPF 3-2004-5038 on December 21, 2004, which included a Notice of Probable Violation, Warning Letter, Notice of Amendment, and Letter of Concern, identifying a total of 14 separate issues that included 3 probable violations, 5 procedural issues and 6 areas of concerns. The 3 probable violations were changed to "Warning Letter" by PHMSA because no civil penalty or compliance order was proposed. One violation involved Plummer to Clearbrook pipeline section of Line 4. The discovery of several anomalies was made within 180 days of completion of ILI of the line, but these anomalies were erroneously classified as "previously repaired" and were excluded from the remediation plan. In another violation OPS stated that "Enbridge's *information analysis procedures did not adequately consider data from other inspections and tests. Also, the process of evaluation of each pipeline segment by analyzing all available data was insufficient to gain a complete understanding of pipeline integrity (195.452 (f)(3)(g)(3))*." Applicable regulations are stated below:

> *§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available*

information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

§452(g) what is an information analysis? In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure.

Enbridge responded to CPF 3-2004-5038 on January 28, 2005. A part of Enbridge's response to citations pertinent to the above mentioned regulations stated that for all hazards (external corrosion, internal corrosion, SCC, weld cracking, mechanical damage), specific defect analysis is conducted. Based on Enbridge's response the PHMSA ultimately closed file on March 20, 2007.

PHMSA conducted a second comprehensive integrity management program review of Enbridge in the weeks of June 12 and June 26, 2006. The detailed protocol inspection format was utilized again to review Enbridge's processes for:

- Identifying pipeline segments that could affect High Consequence Areas (HCAs);
- Integrating information from all relevant sources to understand location-specific risks for these segments;
- Developing and implementing a Baseline Assessment Plan;
- Reviewing the results of integrity assessments;
- Identifying and implementing remedial actions for anomalies and defects identified during integrity assessments;
- Identifying and implementing additional preventive and mitigative measures to reduce risk on pipeline segments that can impact HCAs;
- Performing periodic evaluations and on-going assessments of pipeline integrity; and
- Evaluating Integrity Management Program performance.

This inspection also included review of the implementation and results of the Enbridge integrity management program to-date, including completed integrity assessments, any repair and mitigation actions taken as a result of these assessments, progress in determining and implementing preventive and mitigative measures, periodic evaluations and re-assessments, performance metrics and improvement actions.

A summary report was prepared by PHMSA at the conclusion of the inspection identifying 13 recommendations concerning Enbridge's integrity management Plan, With respect to a Continual Process of Evaluation and Assessment, PHMSA noted during the inspection that: *"The lack of a periodic evaluation process was indicative of the Enbridge approach to integrity management, where the pigging/PIM activities are largely done separate from risk assessment activities. Utilization of available information/risk analysis information appears to be limited to the evaluation of certain additional P&M measures and is not well integrated with key integrity/assessment decisions. In effect, Enbridge IM-related groups operate semi-independently, and it is not clear that overall integration of knowledge and data is occurring on a consistent basis."* No formal enforcement action was taken by PHMSA as a result of the 2006 inspection.

Other PHMSA Actions Related Marshall Accident:

On July 28, 2010, PHMSA issued a Corrective Action Order (CAO) to Enbridge requiring the operator to take specific steps to ensure the safety of the pipeline before it is allowed to return to service. The CAO required Enbridge to submit a return to service plan including procedures for repairs and monitoring the pipeline if it is allowed to resume service. It also required Enbridge to submit an integrity verification plan that includes a comprehensive review of the operating history of Line 6B, further inspections, testing, and repairs within and beyond the immediate failure area. On September 17, 2010, based upon the information gathered, PHMSA proposed an amendment to the CAO setting out expectations for repair of known defects and the collection of additional integrity data. Enbridge agreed to the proposed CAO amendment and PHMSA issued a Final CAO on September 22, 2010. On August 9, 2010, Enbridge submitted its response to CAO and its proposed restart plan. On August 10, after reviewing the response and the restart plan, PHMSA stated that "(the plan) *does not contain sufficient technical details or adequate steps to permit a conclusion that no immediate threats are present elsewhere on the line that require repair prior to any restart of pipeline, even at a further reduced pressure*." After review of the revised plan that was submitted by Enbridge on September 24, 2010, PHMSA approved Enbridge's proposed Line 6B restart plan on September 26, 2010, and authorized a staged restart of Line 6B at a reduced maximum operating pressure (MOP) to begin on September 27, 2010. Enbridge plans to replace a portion of Line 6B in Michigan and Indiana. Integrity verification and remedial work activities on Line 6B are still continuing.

Previous Enbridge Crack Related Failure Investigations:

On March 3, 1991, the 34-inch Enbridge's Line 3 (then Lakehead Pipeline) ruptured near Grand Rapids, MN, releasing an estimated 40,000 barrels of crude oil in an agricultural field, which migrated approximately ¾ of a mile to the Prairie River, upstream of the Mississippi River. An outside laboratory determined that the rupture was caused by a fatigue crack at the toe of the longitudinal seam weld of the pipe. The rupture was not immediately recognized by control center personnel, and no mitigating action was taken. As a result, the pipeline continued operating for approximately 53 minutes after the rupture while the abnormal SCADA indications were being investigated. As a result, the Lakehead's procedures were modified as follows: "*If an operator experiences pressure or flow abnormalities or unexplained changes in line conditions for which a reason cannot be established within a 10 minute period, the line shall be shut down, isolated, and evaluated until the situation is verified and/or corrected.*"

The entire U.S. portion of Line 3 was subjected to hydrostatic pressure testing in 1991 and 1992. Within 2 1/2 years of hydrostatic testing, two subsequent seam leaks occurred on Line 3. OPS stated that efforts to develop alternative technology (to hydrostatic testing) to identify seam related defects in the pipe were being supported industry wide. An Elastic Wave tool, which used wheel-mounted shear wave ultrasonic sensors to identify seam related defects in the pipe, was being developed by the British Gas. In 1995, PHMSA (then RSPA) gave conditional approval to a program utilizing Elastic Wave tool inspections in lieu of additional hydrostatic testing of Line 3. One of the purposes of the program was to determine whether crack detection

ILI technology was capable of identifying sub-critical defects that would not result in a failure during a hydrostatic test. Multiple tool runs were conducted on the 34-inch pipeline, which resulted in numerous excavations and defect examinations. The results of the program were ultimately sufficient for RSPA to accept the use of crack detection ILI on the 34-inch pipeline. The Consent Order which resulted from the March 3, 1991 rupture was closed in May of 1999, and the 34-inch pipeline was allowed to return to full operating pressure.

About 2:12 a.m., central daylight time, on July 4, 2002, a 34-inch-diameter steel pipeline (Line 4) owned and operated by Enbridge Pipelines, LLC ruptured in a marsh west of Cohasset, Minnesota. Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline as a result of the rupture. This accident was investigated by the NTSB.[14]

The cause of the failure was determined to be a fatigue crack at the toe of the longitudinal weld seam of the pipe. The rupture defect had not been reported by any previous ILI inspection that was conducted using the British Gas Elastic Wave tool. RSPA (PHMSA's predecessor agency) issued a CAO as a result of the rupture, which, among other things, required Enbridge to implement an integrity verification program. A portion of the integrity verification program included ILI crack detection inspection using the PII USCD tool, which was the successor to the Elastic Wave tool.

On November 13, 2007, Enbridge discovered a leak on the 34-inch Line 3 at Mile Post 912, near Clearbrook, MN. The failure analysis performed by an outside consultant indicated that the leak was also due to a fatigue crack at the inside toe of the longitudinal weld seam of the pipe. On the inside surface, the crack was reported to be approximately 15 inches long, and grew towards the outside surface of the pipe in an elliptical fashion. This section of pipeline had been previously inspected multiple times using crack ILI technology, including PII's USCD tool, but no defect had ever been reported at this location. Post-accident analysis of the most recent crack ILI data indicated that though there were ultra-sonic reflectors corresponding to the defect location, they were insufficient to meet the reporting criteria that were established at the time.

Enbridge's 26-inch Line 2 ruptured on January 8, 2010, at Mile Post 774, near Neche, ND, spilling a reported 3784 barrels of crude oil. According to the consultant hired by Enbridge, the failure was attributed to a fatigue crack at the toe of longitudinal weld seam on the inside of the pipe. The failure defect was approximately five inches long, with a maximum depth of approximately 75% of the local wall thickness. This pipeline also had previously been inspected for cracks in August of 2009 using PII's USCD tool. The crack feature was classified as a "weld inhomogeneity (IHG)" by PII, and was not reported to Enbridge. As a result of this accident, PHMSA issued a CAO to Enbridge on January 19, 2010. According to PII, post-accident analysis of the ILI data associated with the rupture location indicated local peaking and misalignment at the longitudinal weld seam contributed to a misinterpretation of the ultra-sonic signal.

Enbridge discovered a leak on the 26-inch Line 2 on April 17, 2010, at Mile Post 997.8, near Deer River, MN. This leak was due to a crack-like feature associated with the longitudinal weld seam on the inside of the pipe. This pipeline section had been inspected for cracks in 2009

[14] The NTSB report: NTSB/PAR-04-01; PB2004-916501

using PII's USCD tool. In this instance, PII reported a crack-like defect to Enbridge at this location, but the reported depth did not result in the reported defect being targeted for excavation prior to the failure. Additional analysis work is being performed by Enbridge to reconcile the apparent discrepancy between the tool reported depth and the actual depth.

Recent Accidents in Enbridge Pipeline System:

Enbridge has experienced two cracking related crude oil releases in 2012 that are currently being investigated by PHMSA. Information provided by Enbridge for these two accidents is summarized below.

On February 15, 2012, in Arenac County, MI, oil was discovered in the soil around the 30-inch diameter transmission line, Line 5, at the mile-post 1606. Though no through wall damage was indicated by previous ILI inspections, this joint was selected for excavation based on the 2011 crack ILI results. Enbridge's field analysis showed a short ID initiated crack near the long seam of the pipe. The crack grew radially from the toe of the weld on an angle resulting in breaking the surface on the OD away from the long seam.

On February 17, 2012, oil was discovered in the casing around a dent in a 34-inch diameter transmission line, Line 6A, at mile-post 461.75, at/near girth weld 338420. This joint was selected for excavation based on a dent greater than 2% that was reported with metal loss (a stress concentrator) by a 2011 transverse MFL tool. During the initial stages of excavation oil in the casing was discovered. Field investigation found a dent with cracking. Again, no through wall damage was indicated by previous ILI inspections and previous crack inspections did not report a crack in this dent. Enbridge felt that this is not unexpected of the depth of the dent (>2%) as this would affect the correct entry of the ultrasonic beam.

National Energy Board of Canada Audit

Because the pipeline infrastructure in Canada and the United States is interconnected, in November 22, 2005, PHMSA and NEB entered in to an agreement to improve pipeline safety and enhance cooperation. With this agreement in place, a representative of the NEB was able to attend a portion of PHMSA's 2006 integrity management inspection of Enbridge. Also, some of the NTSB staff investigating the Marshall accident did visit NEB in December, 2011, to discuss NEB's Integrity Management audit findings of Enbridge.

The National Energy Board (NEB) of Canada completed an audit of Enbridge on July 18, 2008, according to Onshore Pipeline Regulations, 1999 (OPR-99). The final NEB audit report was issued on December 19, 2008. In its Integrity Management Program (IMP) findings, NEB identified 7 areas of improvement related to pipeline integrity management program:

1. *The integration of pipeline IMP processes across the Enbridge organization;*
2. *The definition and evaluation of level of training, qualification and competency of contractors;*

3. *A complete and integrated process for identification of pipeline integrity hazards/threats;*
4. *A risk assessment process with results that are integrated validated and applied by all responsible departments for their integrity-related programs;*
5. *A complete, integrated and validated pipeline integrity re-assessment process;*
6. *A complete monitoring and inspection program ensuring qualified personnel provided with all relevant records; and*
7. *A complete, integrated and documented pipeline integrity hazard/threat prevention program.*

Within these seven areas: monitoring and inspection, hazard/threat identification; IMP role interaction among teams, team communications for IMP development and implementation; complete hazard/threat assessment and repair records; Engineering assessments; IMP document management process and documents for some IMS elements; were some of the fourteen sub-areas that were identified by the NEB as findings of noncompliance in the Enbridge pipeline integrity management program.

Because of the involvement of multiple departments in the IMP (e.g., integrity management, engineering, and risk management) and interconnected areas of responsibility, the NEB felt that Enbridge needs structured management program and formal documentation process across the Enbridge organization for the pipeline integrity management program to be effective. Materials Technology team was involved in ILI, NDE work related to the crack and dent management, but was not listed as responsible party in related Enbridge documents.

In addition to qualifications and competency of non-destructive examination (NDE) technicians, the NEB believed that Enbridge IMP needed a complete hazard and threat identification assessment process that should include fatigue-dependent cracking, amongst other threats. The NEB noted that "*assessment process and data for determining the crack and corrosion ILI frequency are required to be improved to prevent failures from reoccurring. Ongoing evaluation of the effectiveness of the crack management plans is required such that ILI frequency can be reliable. Subsequently, the following areas, but not limited to, are required to be improved upon:*

a) ILI Accuracy of crack detection and sizing;
b) Validity of Crack Growth Modeling in regards to input data (i.e. material properties and growth coefficients) and ongoing field verification of assumptions; and
c) Determination of the crack—susceptible pipelines accounting for the level of identified data uncertainty (i.e. unknown and non-reliable input data) and continuous validation by field investigation."

Lack of integration between Operations Risk Management (ORM) and Pipeline and Facility Integrity Management, particularly in the area of risk assessments performed by these departments, was identified as other area of noncompliance. In another finding, NEB stated that "validation of *the corrosion assessment interval results and the evaluation of their influence in the external corrosion mitigation and monitoring programs are required. Similarly, validation of crack detection ILI performance, crack growth modeling, re-inspection frequency, susceptibility to cracking of Enbridge's pipeline segments, and* *the evaluation of their influence in the crack mitigation and monitoring programs are also required."*

During the audit NEB discovered that coincidental features were being assessed independently by each team. The NEB also felt that a complete integrated process amongst all departments involved is needed to identify, monitor, assess, and mitigate, threats for the IMP to be effective in preventing them.

Enbridge submitted its corrective action plan to NEB on February 2, 2009.

Transportation Safety Board of Canada

Transportation Safety Board (TSB) of Canada investigated Enbridge Line 3 rupture that occurred at MP 506.2217, near Glenavon, Saskatchewan on April 15, 2007. This 34-inch (864 mm) crude oil pipeline was installed in 1968, had 0.28 inch (7.1 mm) thick wall, DSAW longitudinal seam and was manufactured according to 1967 edition of the API 5LX52 pipe standard. It spiral-wrapped polyethylene tape coating, and the maximum operating pressure (MOP) was (4495 kPa). The failure was attributed to cracking that initiated at a shallow corrosion groove with a depth of less than 0.4 millimeters (mm) (5 per cent of the pipe wall thickness) along the top toe of the longitudinal weld that propagated by fatigue in a flat manner through the pipe.

Prior to the eventual rupture in 2007, the ruptured pipe joint was excavated in 2002 following an ILI inspection in1999. In 1999 ILI inspection the anomaly that eventually resulted in rupture was sized at less than 12 per cent in depth and was not identified as requiring immediate attention. In 2005 operation of line 3 was changed that increased pressure cycles in the Line, but Enbridge's fatigue analysis indicated that the service life would still be acceptable. The ultrasonic crack detection tool ILI conducted in 2006 sized the anomaly that resulted in rupture in 2007 in the 12.5 to 25 per cent range and its estimated failure pressure was greater than the hydrostatic test. TSB stated in the report that "*The verification procedure used by Enbridge was to compare ILI estimated crack sizes, and associated calculated failure pressures, with results obtained in the field by non-destructive ultrasonic inspection or crack grinding, or a combination of the two. Enbridge considers field and ILI data to be sufficiently accurate if the data falls within an error band of plus or minus 10 per cent.*"

The TSB determined that "*The accuracy of the predictions of the crack growth model depends on the accuracy of the input parameters, including initial crack size. If any of these parameters have been underestimated, actual crack growth rates will exceed predicted values."* The TSB also noted that the 2006 ILI data that Enbridge used to calculate failure pressure ratios did not have non-conservative bias. The TSB also felt the accident indicates that some uncertainty can exist in the field non-destructive examination of the pipe. Some of the key findings of the TSB's investigations were:

- During the field inspection in February 2002, the weld cap on the longitudinal weld may have masked the identification of the severity of the fatigue crack.
- Although Enbridge recalculated the crack growth rate to reflect the more aggressive

pressure regime which began in November 2005, the input parameters used by Enbridge during that analysis did not accurately reflect the actual crack growth rate.

- The analysis of the 2006 in-line inspection data resulted in the underestimation of the depth of the deepest section of the fatigue crack.
- The depth of short, deep sections of cracks may be underestimated during both the analysis of in-line inspection data and the non-destructive examination of the pipe in the field which would affect the identification of cracks requiring repair.

Other Pertinent Information:

Managing System Integrity for Hazardous Liquid Pipelines-API Standard 1160:

In this standard, the API points out to the hazardous liquid pipeline operators that compliance approach alone may not be enough to develop a high quality integrity management (IM) program, rather regulation should be used as a foundation to build their program upon. Some of the "Guiding Principles" identified by the standard are summarized below:

1. *An integrity management program must be flexible.*
   The program should be customized and must be continually evaluated and modified as appropriate to accommodate changes in the pipeline system
2. *The integration of information is a key component for managing system integrity.*
   It is important to integrate all available information from various sources in the decision making process
3. *Preparing for and conducting a risk assessment is a key element in managing pipeline system integrity.*
   This analytical process involves the integration and analysis of design, construction, operating, maintenance, testing, and other information about a pipeline system.
4. Assessing risks to pipeline integrity is a continuous process.
   Analyzing for risks in a pipeline system is an iterative process. The operator will periodically gather additional information and system operating experience. This information should be factored into the understanding of system risks.

The standard points out that using the existing data, all "coincident occurrence" of suspected high-risk conditions or events should be compared, and stresses importance of timeliness, quality and completeness of data.

The standard also gives overview of in-line inspection and hydrostatic testing methods, and briefly describes advantages and disadvantages of these two techniques in evaluating pipeline integrity.

CEPA Stress Corrosion Cracking Recommended Practices:

The 1997 Canadian Energy Pipeline Association (CEPA) Stress Corrosion Cracking (SCC) Recommended Practices were developed[15] to address longitudinally oriented near-neutral or low pH[16], SCC in the pipelines, and were based on experience of CEPA's membership companies. CEPA has found that polyethylene coated pipes are more susceptible to low pH SCC and SCC will occur if external coating is disbanded. Some correlation between corrosion and SCC has also been observed.

For discrete "significant"[17] SCC, CEPA recommended grinding the cracks, replacing the impacted pipe, or sleeving the pipe once the cracks have been ground out as acceptable mitigation methods. According to Enbridge, for Line 6B significant crack length would be approximately 1 to 2.5 inches. Enbridge stated that definition of "significant" SCC has been removed from CEPA's 2007 revision of "Stress Corrosion Cracking Recommended Practice."

If "significant" SCC could potentially be present at many locations within a pipeline segment, CEPA's recommended mitigation approach included hydrostatic retesting, in-line inspection if appropriate tools are available, extensive pipe replacement, and re-coating. CEPA considered hydrostatic retesting and in-line inspection as temporary mitigation techniques, where as re-coating, sleeving and grinding repairs and replacing the pipe could permanently mitigate SCC threats.

CEPA was aware that crack detection ILI tools can find various longitudinal defects (cracks) and not just from SCC and stated that "*Some types of cracks, such as corrosion fatigue in the toe of the long seam, are easier to identify than SCC because they occur as isolated defects with a fairly wide opening in one specific area of the circumference.*"

Enbridge Post-Accident Threat Assessment Review:

Dynamic Risk Assessment Systems, Inc., conducted a system-wide threat assessment review for Enbridge in 2011. Based on the Enbridge's "1984 to 2010 leak" report database, the report concluded that 26.8 percent mainline failures were caused by the manufacturing defects, and were attributed to seam defects. The report recognizes that *"While manufacturing defects are commonly thought of as being stable, flaw growth in service does occur, especially in liquids pipelines where operating pressure cycles have the potential to be significant."* Also, 14 percent

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[15] CEPA issued a second edition of the Stress Corrosion Cracking Recommended Practice document in 2007.

[16] CEPA defines Low pH SCC as "*pipeline SCC associated with an electrolyte which has a pH in the neutral range (pH 6-8); the reference to "low-pH" is simply used to differentiate it from the "high-pH" SCC form which is associated with a more alkaline water; the cracking in this form of SCC is wide, non-branching and follows a path across the grains of the steel (i.e., transgranular).* " CEPA defines High pH SCC as "*pipeline SCC which is associated with an electrolyte which has a pH in the alkaline range, specifically greater than pH 9.3 and in which the cracking follows an intergranular path and is often branched which is associated with a more alkaline water*."

[17] According to CEPA, a SCC colony is assessed to be "*significant*" if the deepest crack, in a series of interacting cracks, is greater than 10% of wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical crack length of a 50% through wall crack at a stress level of 110% of SMYS.

failures were attributed to external corrosion and narrow axial external corrosion was noted in at least one failure (Figures 2 and 3). Environmentally assisted cracking (EAC) was responsible for 3 percent of the failures. The report stated that "*external metal loss is one of the morphological traits associated with near-neutral pH SCC and corrosion fatigue.*" Because external corrosion was associated with most of the failures, the report further stated that *"environmentally assisted cracking mechanism that is most prevalent along Enbridge's liquid pipeline system is either near-neutral pH SCC or corrosion fatigue."*

For Line 6B the report attributed manufacturing defects and external corrosion as significant threats and SCC as moderate threats. Though all of the Enbridge's pipeline failures involving manufacturing defects were attributed to seam related defects, no potential considerations for future mitigation were identified in the report.

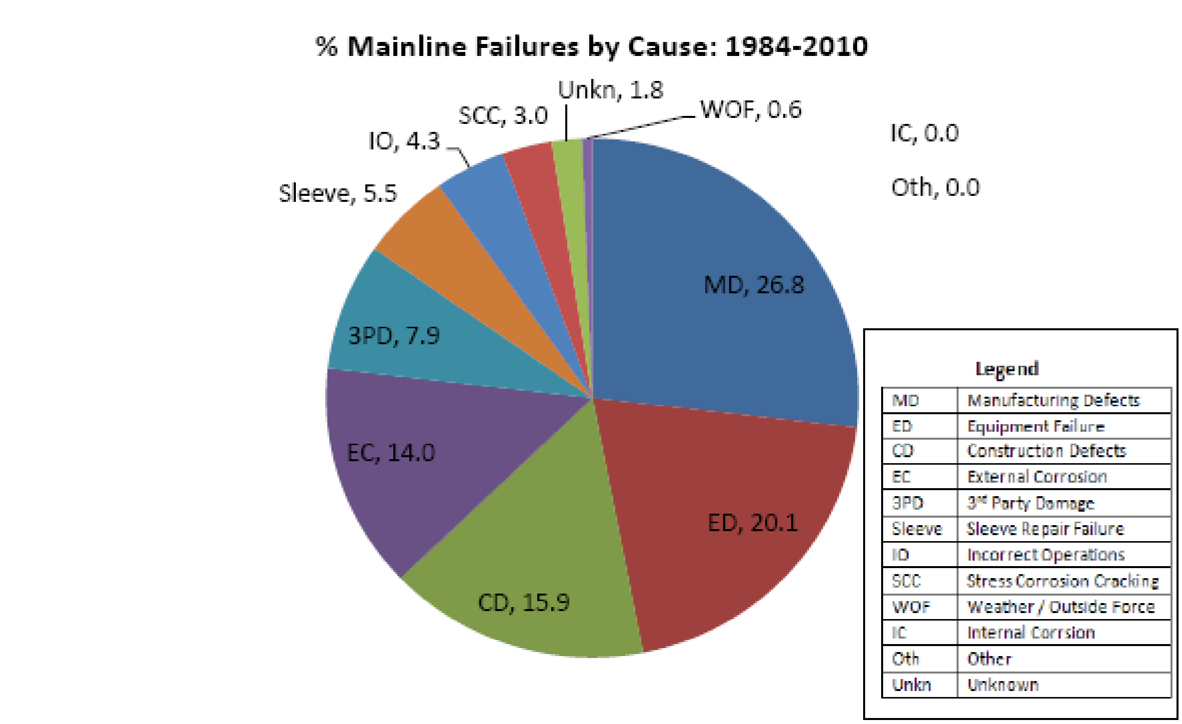

Figure 2: Percent of Enbridge Main-Line Failures by Cause.

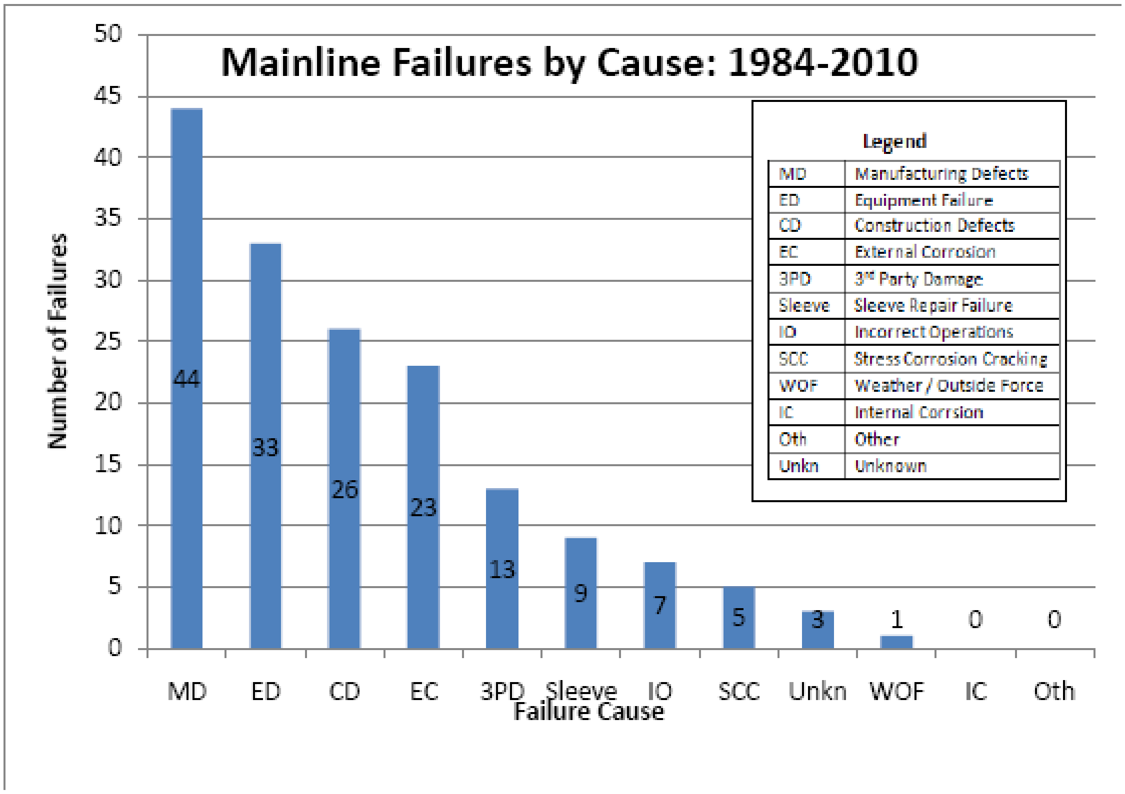

Figure 3: Number of Enbridge Main-Line Failures by Cause.

List of Attachments

Attachment–I:	Table I:	Fitness for service calculations performed by Enbridge at NTSB's request using corrosion, crack and tool tolerance data.
	Table II:	The ILI data provided by PII for cracks in corrosion at two locations in the ruptured pipe joint.
Attachment–II:	Table III:	Enbridge Line 6B in-line inspection information.
Attachment–III:	Table IV:	Enbridge Line 6B USWM 1999 in-line inspection information.
	Table V:	Consolidated ILI listing provided by PII for GW 217720 for 2004 to 2009.
Attachment–IV:	Figures 4 through 7, summarizing ILI data.	
Attachment–V:	List of references.	