

May 22, 2012

**ENBRIDGE ENERGY, LIMITED PARTNERSHIP
PARTY SUBMISSION
INVESTIGATION OF JULY 2010 LINE 6B ACCIDENT
NEAR MARSHALL, MICHIGAN; NTSB ID: DCA 10MP007**

PREAMBLE

Enbridge Energy, Limited Partnership (“Enbridge”) appreciates the opportunity to provide this Party Submission. Enbridge has also appreciated the opportunity to work side-by-side with other Party members in the pursuit of the facts of this accident with the common objective of making improvements in the safety of Enbridge’s operations as well as those of the entire pipeline industry. As of the filing of this Party Submission, Enbridge understands that not all Factual Reports have been completed as Enbridge continues to respond to inquiries and requests for information from certain fact report working groups. As a result, Enbridge is not certain whether the conclusions stated in this Submission will necessarily accord with the findings of all of the Factual Reports in all respects. If, upon review of all Factual Reports, Enbridge determines that it is necessary to address any factual finding, Enbridge will promptly file a supplemental Party Submission.

1. INTRODUCTION

Enbridge’s Line 6B is a 30-inch diameter pipeline that runs from Griffith, Indiana, to Sarnia, Ontario. Constructed in 1969, Line 6B has an average daily capacity of 283,000 barrels. The line, which generally carries light synthetic and heavy and medium crude oil, supplies refineries in Ohio, Michigan, Pennsylvania and eastern Canada.

Line 6B was operating normally on July 25, 2010 when it was shutdown to facilitate a routine scheduled delivery of product into Stockbridge, Michigan. At approximately 17:58, at the initiation of the scheduled shutdown, a loss of containment occurred near mile post 608 (the “Accident”). The Accident occurred as the result of a confluence of events that collectively contributed to the release of approximately 20,082 barrels of crude oil. The Accident site is located approximately 0.6 miles downstream of Enbridge’s Marshall pumping station.

Enbridge has determined the following as a result of its internal investigation and participation in the NTSB investigation:

- The probable cause of the loss of containment was stress corrosion cracking (“SCC”) in the pipeline.
- Enbridge has a well-established and comprehensive integrity management program implemented on Line 6B and has conducted various in-line inspections (“ILI”) of Line 6B since 1976. In particular, between 2004 and 2009 Line 6B was inspected three times for metal loss, once for cracking, three times for geometry features and once using an innovative approach for identifying mechanical damage. Based upon the comprehensive data from all the inspections, the potential for the release at the location near Marshall was neither anticipated nor foreseen. The SCC feature identified as likely

responsible for the leak represented an unusual circumstance, far more severe than anything else identified or projected on the pipeline before or since the Accident.

- The NTSB's Materials Report showed no significant internal corrosion in the ruptured pipe joint.
- Although the maximum operating pressure for Line 6B was 624 psig, Enbridge was operating the pipeline with a maximum discharge pressure of 523 psig at the Marshall station prior to the Accident. The maximum-recorded discharge pressure at the Marshall station around the time of the failure was 486 psig, well below both the maximum operating pressure of Line 6B and the maximum discharge pressure at the Marshall station.
- The unanticipated failure occurred during a scheduled shutdown, when a significant loss of pressure is normal. Thus, the initial mass balance system (MBS) alarm that occurred in the main control room at the time of the scheduled initiation of the shutdown was attributed to a column separation after being investigated by an MBS analyst. (Column separation, a well-known operating condition on liquids pipelines, forms when depressurization of a section of pipe occurs and some of the oil in the pipe is vaporized and moves from liquid to vapor state.) Because the frequency of alarms during a shutdown process was not unusual, the experienced crew did not regard the alarms, by themselves, to suggest a loss of containment.
- When the scheduled restart of Line 6B began at 4:04 a.m. on July 26, the new shift in the control room also attributed the MBS alarms to a column separation. Because of the unusual circumstances surrounding the pipeline failure described above and subsequent human errors, the trouble-shooting of very experienced personnel in the control room over the next seven hours focused on resolving the multiple alarms and column separation rather than a potential loss of containment.
- Hours before the scheduled restart of Line 6B, numerous 911 reports from members of the public about a possible gas leak in the area were made, prompting both the Marshall City and Marshall Township Fire Departments to investigate these reports. Neither team of investigators located the source of the odor and departed the area without resolution or report to Enbridge (or to any other local oil or gas company). As part of Enbridge's ongoing public awareness program, both fire departments had recently participated in a safety awareness training program conducted by Enbridge.
- The torrential rains in the area immediately prior to the failure (totaling over 5 inches) accelerated the spread of the release into Talmadge Creek and thereafter into the Kalamazoo River, as well as significantly hindered the efforts to limit and clean up the release. Had this amount of rain not fallen before the Accident, or had Enbridge received notification of the Accident at any time before the early morning restart of Line 6B, the oil would not likely have reached even Talmadge Creek.

As a result of an unusual coincidence of events described above, positive identification of a crude oil release did not come until approximately 11:16 a.m. on July 26 – over 17 hours after the Accident occurred – when Enbridge's Control Center Operations ("CCO") received a call from a local natural gas company advising of oil in a creek near Division Road in Marshall.

Enbridge management responded immediately. Within a half hour, at 11:45, an Enbridge first responder confirmed oil on the ground and called the CCO emergency line. Regional management in Chicago contacted Enbridge executive management and initiated Enbridge's emergency response protocol, including calls to enlist internal and external resources and to notify the appropriate regulatory agencies. Remote controlled valves were closed by the CCO, thereby confining the failure within a three-mile section.

Along with a team from Enbridge's regional offices throughout North America, Patrick D. Daniel, Chief Executive Officer of Enbridge Inc., arrived on scene that evening and spent the next two months on site overseeing the extensive containment efforts, meeting with federal, state and local officials, and working with health care providers, community leaders and affected individuals to ensure that Enbridge put things right. Mr. Daniel pledged that Enbridge would take full responsibility to address the impacts of the release on the natural environment and on individuals and businesses in Marshall, Battle Creek and the surrounding area. Enbridge is doing so.

Given the dedication of Enbridge's employees, the experience of its pre-identified emergency crews, the efforts of the approximately 1,200 field personnel deployed at the peak of the response (including 500 Michigan residents) and the local, state and federal officials who worked with Enbridge, the release was quickly contained. Within one week, Enbridge succeeded in removing most of the released oil off the Kalamazoo River. By the end of August 2010, Enbridge had met the Unified Command's goal of cleanup at the leak site and along Talmadge Creek. By the end of September, Enbridge had completed the bulk of the cleanup. Enbridge continues with remediation efforts, working with the Environmental Protection Agency (EPA), the Michigan Department of Natural Resources and Environment and other officials to restore the affected areas and to establish a long-term monitoring plan.

In September 2010, Mr. Daniel testified before Congress about the Accident. He said in part: "Once the investigations into this incident have been completed, Enbridge is fully committed to addressing whatever changes might need to be implemented so that we and others in the industry can avoid a repeat of this incident. We intend to work with you to ensure that the Committee's concerns and those of the communities in which we operate are fully addressed." Enbridge is doing so.

Since the Accident, Enbridge has reviewed all relevant pipeline integrity documentation to assess what may have caused the pipe section to fail and to prevent the recurrence of this type of loss of containment anywhere on the Enbridge system. Numerous process and procedure modifications and improvements have been implemented by Enbridge. Examples of these actions are described in section 5.

2. BACKGROUND ON ENBRIDGE

Enbridge is a leader in the energy delivery industry in North America. Enbridge's core values of integrity, safety and respect guide the way it makes decisions and conducts business. Enbridge strives to operate with high standards in all interactions with customers, investors, employees, partners, regulators and in the communities through which it operates. Moreover, Enbridge is committed to ensuring compliance with applicable laws in every jurisdiction in which it operates.

Enbridge has grown its business substantially over the past 60 years. Today, Enbridge operates one of the world's longest petroleum liquids pipeline systems, serving customers

throughout Canada and the United States. Last year, Enbridge delivered approximately two million barrels per day of oil to markets throughout the United States and Canada. The Enbridge pipeline system currently delivers more than 12 percent of the total daily imports of crude oil into the United States.

As the operator of North America's largest crude oil pipeline system, Enbridge is committed to safely and reliably delivering energy to people across the continent. The goal is to have no leaks or releases, ever. Based on miles of pipeline Enbridge operates, its line break rate is well below the industry average. The substantial sums spent annually on pipeline integrity programs support activities such as corrosion control, monitoring and advanced inline inspection technologies that provide a view of a pipeline at fractions of an inch. Enbridge also runs regular ground and aerial pipeline patrols, and maintains a comprehensive program of digs to test the integrity of its pipelines. In addition, Enbridge has developed strong public awareness programs.

3. FIELD RESPONSE TO THE ACCIDENT

Approximately 20,082 barrels of crude were released as a result of the failure. Some of the oil entered Talmadge Creek and from there a lesser amount entered the Kalamazoo River; the rest remained in the vicinity of the failure. There were no fatalities.

Upon first notification of the release of oil on the morning of July 26, the pipeline was further isolated, which as noted above already had been shut down for a planned delivery. That day, crews began installing containment boom that had been pre-positioned in Marshall. The initial focus during the first week was collecting the oil from the Kalamazoo River and then recovery of free oil from the immediate ground around the leak site.

To address the needs of the local communities and to make information available as quickly and reliably as possible, Enbridge began that day contacting residents in the areas of greatest direct impact along Talmadge Creek. By 9:45 p.m. on July 26, a hotline was set up and the number was provided to the local media to publicize. Enbridge also quickly published a website for the Accident – www.response.enbridgeus.com – where area residents could find up-to-date information on the Accident, measure the Enbridge's response to it and submit comments or questions. Within two weeks, Enbridge had opened two community centers staffed with a team of employees to work directly with residents to provide appropriate assistance.

After arriving on scene on July 26, Mr. Daniel made it a point to meet with as many people as possible, often in their homes, so that they could share their concerns directly with him and so that Enbridge could respond as quickly as possible to address their concerns. Enbridge established processes to provide direct assistance for pre-paid hotel stays, equipment and services; reimburse for cost of living expenses and other qualified expenses incurred directly as a result of the leak, voluntary evacuation and clean-up activities; receive and pay claims for property and personal damages (such as business interruption, nuisance and inconvenience and temporary land access and use); pay medical expenses for those individuals without insurance or a primary care physician; and purchase homes from adversely affected individuals at the pre-release appraisal value.

4. PIPELINE INTEGRITY, INSPECTION TECHNOLOGY AND ANALYSIS

Information provided within the NTSB Materials Report suggests that the principal metallurgical feature that led to the July 2010 Line 6B failure near Marshall, Michigan was environmentally assisted cracking (commonly referred to as stress corrosion cracking). In this section, we describe the integrity actions that Enbridge undertook as part of the crack inspection and mitigation program it implemented from 2005 to 2010 on Line 6B.

With the primary cause of the failure identified as stress corrosion cracking, the draft NTSB Integrity Management Factual Report that Enbridge has reviewed suggests that the appropriate methodology for ILI data analysis in order to detect and assess the nature and extent of stress corrosion cracking is to add crack depth to corrosion depth if these features are coincident. Enbridge does not believe that simply adding crack depth to corrosion depth reflects industry practice (either at the time of the Accident or today) and that this suggestion does not provide a practical course of action for the future. Because of this apparent disagreement over a material issue of Integrity Management, this section of the Enbridge Party Submission provides a detailed review of the engineering technologies, processes and practices relevant to this area and how they were appropriately applied by Enbridge in accordance with regulatory and industry standards with respect to Line 6B.

Background. The pipeline industry uses sophisticated ILI technology to identify features that may suggest, indicate, contribute to or result in a loss of pipeline integrity. These tools are generally threat-specific:

- Magnetic Flux Leakage and straight beam Ultrasonic: used to detect metal loss, corrosion and gouges
- Caliper tools: used to detect dents and other geometric anomalies
- Ultrasonic Shear Wave: used to detect cracks and other linear features

Two industry documents describe the processes for ILI vendors to follow in order to develop their performance specifications: the NACE International RP0102 In-Line Inspection of Pipelines (revised in 2010) (“NACE 0102”) and the American Petroleum Institute (“API”) Standard 1163 In-Line Inspection Systems Qualification Standard (“API 1163”). API 1163 requires ILI tool vendors to identify in their reporting specifications any physical or operational factor or condition that may limit detection thresholds and sizing accuracies. If it is known that corrosion could influence the detection or sizing capability of the crack-detecting ultrasonic shear wave tool, that fact should be included in the ILI vendor’s performance specifications. Enbridge’s tool vendor, Pipeline Integrity International (“PII”), developed its Ultrasonic Crack Detection (“USCD”) tool in accordance with API 1163.

No indication of such a limitation had been promulgated by ILI vendors. Also, the state of the art in ILI data analysis did not contemplate this as an issue. As a pipeline operator, Enbridge is aware that there could be conditions or circumstances that affect the accuracy of the collected ILI data. Such items that could impact ILI data quality are investigated by way of field excavation verification and ILI data calibration processes.

Enbridge Inspection and Analysis in 2005-2006. A comprehensive integrity assessment, testing and remediation program had been underway on Line 6B for many years prior to the Accident. In accordance with 49 CFR 195.452(e), Enbridge completed a risk assessment on Line 6B that integrated all relevant integrity data sets and supported the ongoing

implementation of the monitoring and mitigation plan. Specific to fatigue and environmentally assisted cracking, the risk assessment supported the scheduling of a baseline crack assessment in 2005 using the shear wave ultrasonic crack tool (USCD) supplied by PII. Figure 1 below is a summary of the key integrity data relevant to the cracking threat that was integrated to complete the risk assessment.

Figure 1

ENBRIDGE Enbridge Pipelines - Crack Susceptibility Analysis
PRIORITY RANKING TABLE

This table describes a grading system for Crack ILI of the Enbridge pipelines in their trap to trap segments. Each of the segments has been evaluated with respect to their history of crack failures, their long seam weld type and manufacturer, occurrences of SCC, and their typical operating pressure cycling history. Each of these categories has been graded by a senior engineer in the Pipeline Integrity Department using a numbering system between 1 and 5. 1 represents the highest contribution to crack susceptibility and 5 represents the lowest contribution to crack susceptibility. Some of the sections of the pipeline will have multiple gradings in some of the categories where multiple grading criteria apply. The overall likelihood grading is determined by adding up the lowest score in each of the four columns. The segment with the lowest overall likelihood grading would therefore have the highest likelihood of cracking susceptibility.

The last column of the table lists the recommendation for in-line inspection of that particular trap to trap segment. While the susceptibility likelihood and consequence rankings provide the bulk of the reasoning for this recommendation, additional considerations for select segments are also provided in the comments column.

| Grading Criteria | | | |
|---|---|---|---|
| Pressure Cycling | Previous Crack Failures | Additional Comments | Recommendation Level |
| 1. Frequent start stop operation 2. Significant fluid property changes 3. Infrequent start stop operation 4. Insignificant fluid property changes | 1. Ruptures 2. Leaks 3. Exhibited Fatigue 4. No Fatigue 5. No Crack Failures | Comments stating any other relevant information as to why the section is being considered for ILI or not. | 1. Recommendation level 1 dictates the need to conduct ILI immediately 2. Recommendation level 2 indicates that the potential need for monitoring is high. These segments will be prioritized for the probabilistic susceptibility assessment process. 3. Recommendation level 3 indicates a low need for on-line monitoring but will be evaluated using the probabilistic susceptibility assessment process. |
| Weld Type/Manuf. | Field Results for SCC | | |
| 1. Manufacturing flaws in the long seam that have initiated ruptures. 2. Manufacturing flaws in the long seam that have initiated leaks. 3. Manufacturing flaws in the long seam that have initiated fatigue 4. Manufacturing flaws in the long seam that have not initiated fatigue 5. No history of manufacturing flaws at the long seam. | 1. Frequent SCC discovered 2. Less Frequent SCC discovered 3. Infrequent SCC discovered 4. No SCC reported | | |

| Line No. | Trap Section | Section Length [km] | Dia. [in.] | Last Crack Inspection Date / Tool | Pressure Cycling | Weld Type/Manuf. Defects | Longseam Crack Failures | SCC | Overall Likelihood Grading | Consequence | | | Recommendation Level | Proposed Inspection Year | Additional Comments |
|----------|-------------------|---------------------|------------|-----------------------------------|------------------|--------------------------|-------------------------|-----|----------------------------|-------------|------|------|---|--------------------------|---|
| | | | | | | | | | | Normalized | Peak | Year | | | |
| 6B | Griffith - Sarnia | 471.409 | 30 | N/A | 3 | 2, 4 | 2, 4 | 3 | 10 | 2.59 | 6.08 | 16 | Level 2. This recommendation is based on the fact that there has not been a history of crack ruptures on this segment and the segment has the second lowest susceptibility ranking. | 2005 | One long seam crack-like failure occurred. This was a lack of fusion 94" long in the FW at MP 1566 in 1970. Proposed to inspect the last half of this pipeline in 2005 based on the fatigue analysis. |

Enbridge believes the best approach to confirm the sizing capability of ILI tools, supported by industry practice and referenced in both NACE 0102 and API 1163, is to use field verification to calibrate ILI data. Specifically, API 1163, section 9.3 (“Using Verification Measurements”) states:

When verification measurements are used, a comparison shall be made between reported and measured anomaly characteristics to verify the accuracy of the reported inspection results and to demonstrate that the reported results are consistent with the performance specifications. The comparison analysis shall be statistically valid and based on sound engineering practice.

Enbridge followed this approach in its 2005 ILI and dig program for Line 6B, in using field assessment data to calibrate ILI data and identify any notable deviations in ILI tool accuracy. Integration of crack and metal loss ILI data is achieved by assessment of such features through field assessments and comparisons with ILI data.

The core objective of a pipeline integrity dig program based upon ILI tool data is to remediate features that have grown through service such that they continue to meet integrity fitness for purpose criteria. Such a program also is intended to gather sufficient data to investigate and define ILI tool accuracy and integrate analysis results into possible redesign of the dig program as well as to determine the appropriate ILI inspection interval. Pipeline integrity management processes inherently include non-trivial uncertainties such as accuracy variability in key input data (e.g. ILI data) that are managed through the application of reasonable engineered safety factors and levels of conservatism (i.e. sound engineering practices).

The Line 6B integrity dig program was designed to ensure that crack features meeting fitness for purpose investigation criteria were excavated, assessed and, where necessary, repaired. The program also included a statistically relevant number of features that were

assessed to support trending, calibration and verification activities. Figure 2 below is an excerpt of the feature selection algorithm, showing the crack-like and crack-field excavation criteria.

Figure 2

| TABLE I: USCD FEATURE DISPOSITION SUMMARY / MINIMUM EXCAVATION CRITERIA | | | | | | | | | | |
|---|------------------------|--|---|---|--|--|---|--|---|---|
| USCD FEATURE | | PREVIOUS FIELD VALIDATION | | 2006: INTEGRITY TREATMENT OF FEATURE: PHASE I | | | | 2008 SCC INVESTIGATION GW136800-137830 | 2009/10: PHASE 2 | 2010: PHASE 3 |
| CATEGORY | DESCRIPTOR OF INTEREST | NATURE OF FEATURE | ILI DETECTION AND SIZING ABILITY | DIMENSIONS FOR FFP | INVESTIGATION CRITERIA | NOTES | TRENDING RESULTS | INVESTIGATION CRITERIA / TRENDING OBSERVATIONS | INVESTIGATION CRITERIA | INVESTIGATION CRITERIA |
| Crack Like (CL) | - | High expectation of crack with variable depth along length | <ul style="list-style-type: none"> Good ability to define depth and length | Use best available ILI data: (a) feature profile (b) max depth / total length | <ul style="list-style-type: none"> Investigate according to FFP¹ | <ul style="list-style-type: none"> Profiles for all 25-40%, all-hydro (except 5 surface breaking laminations) Select all with profile ffp<hydro (except 5 surface breaking laminations) | <ul style="list-style-type: none"> Depth trending meets tool tolerances or is conservative for all but 1 feature Profile max depths align well with field max depths | <ul style="list-style-type: none"> Selected if on the joints of interest None located on these joints. | <ul style="list-style-type: none"> Selection of CL based on fatigue growth | <ul style="list-style-type: none"> CL features based on conservative fatigue growth CL features associated with metal loss CL at weld within 3m of station |
| Crack Field (CF) | - | High expectation of SCC | <ul style="list-style-type: none"> Good ability to define maximum depth and interacting length | Conservatively use max depth and total length | <ul style="list-style-type: none"> Investigate according to FFP¹ | <ul style="list-style-type: none"> Select all 25-40%, and all LI>=2.5" use trending to confirm max depth / interacting length | <ul style="list-style-type: none"> Majority SCC, some features were metal loss Features 12.5-25, 25-40 trend well Several features <12.5 reported between 12.5 and 25% deep | <ul style="list-style-type: none"> Increase selection of CF from a high density locations; includes 25-40, 12.5-25, and <12.5 features Trending consistent with Phase 1 | <ul style="list-style-type: none"> Selection of CF features to confirm growth or no growth | <ul style="list-style-type: none"> CF features based on conservative crack growth CF features associated with metal loss |

Aligned with the direction contained in the industry documents, Enbridge conducted field assessments of a selection of ILI reported features in each of the depth buckets as shown in Table 1 below:

Table 1

| Depth | Crack-Likes | Crack-Fields |
|----------------------|-------------|--------------|
| <12.5% | 20/571 | 73/1264 |
| 12.5 to 25 | 28/320 | 44/410 |
| 25 to 40 | 12/23 | 4/4 |
| >40 | 0/0 | 0/0 |
| Total Field Assessed | 60/914 | 121/1679 |

Statistical analysis¹ demonstrates that the number of features assessed was a highly representative sample of the total population of features identified through the USCD ILI.

The accuracy of the USCD ILI tool was investigated and compared with the performance specification provided by PII. Table 2 summarizes the depth sizing results from field investigations for crack-likes and crack-fields.

¹ Elementary Survey Sampling, 5th ed., Richard L. Schaeffer, William Mendenhall III, R. Lyman Ott. Duxbury Press, 1996, page 99.

Table 2

| | Crack-Likes | Crack-Fields |
|---|--------------------|---------------------|
| Probability of Sizing (1) accounting for one tool tolerance | 98% | 97% (2) |
| Notes: (1) Features with field assessed depths shallower than reported by ILI are included in meeting the POS value. (2) Accounting for SCC growth at 0.15 to 0.20 mm/year from the time of inspection to the time of field assessment. | | |

The 2005 USCD ILI tool specification states a 90% confidence of sizing features correctly within the depth bucket and accounting for tool tolerance of 40 mils. The results summarized in Table 2 provide support that the 2005 USCD ILI data was trending within expected and acceptable accuracy ranges.

Enbridge undertook an excavation program of over 75 digs and assessed over 300 crack features for ILI data trending and calibration. This program was conducted in alignment with API 1160 and 1163 and PHMSA regulations. Enbridge approached the investigation into the characterization capability of the USCD tool through field calibration activities. This applied to crack features that were coincident with corrosion. Through these calibration activities the integration of the coincident features was accomplished and represented in the resulting analysis and trends. Evidence gained from these digs demonstrated that in cases where cracks and corrosion were coincident the corrosion had no impact on the accuracy of crack sizing. See Table 3 for a summary of the dig results as part of the 2005 ILI dig program.

Table 3

| | Sized Accurately or Conservatively | One tool tolerance (0.5mm) above depth bucket | Two tool tolerances (1.0 mm) above depth bucket |
|---|---|--|--|
| All Field Assessed Crack Fields(SCC) | 80% | 17% | 3% |
| Field Assessed Crack Fields Coincident with Corrosion | 80% | 20% | 0% |

Note: Includes all features with ILI reported depths greater than 12.5%

Calibration results based upon the completed field assessments for all digs provided the key insights below.

- The most significant feature identified in the ILI data and field assessments had a calculated safety factor of 1.18 over the maximum operating pressure of the pipeline. This result suggested that the inspection and mitigation program had been

completed in a timely manner, well before the reliability of the pipeline was compromised.

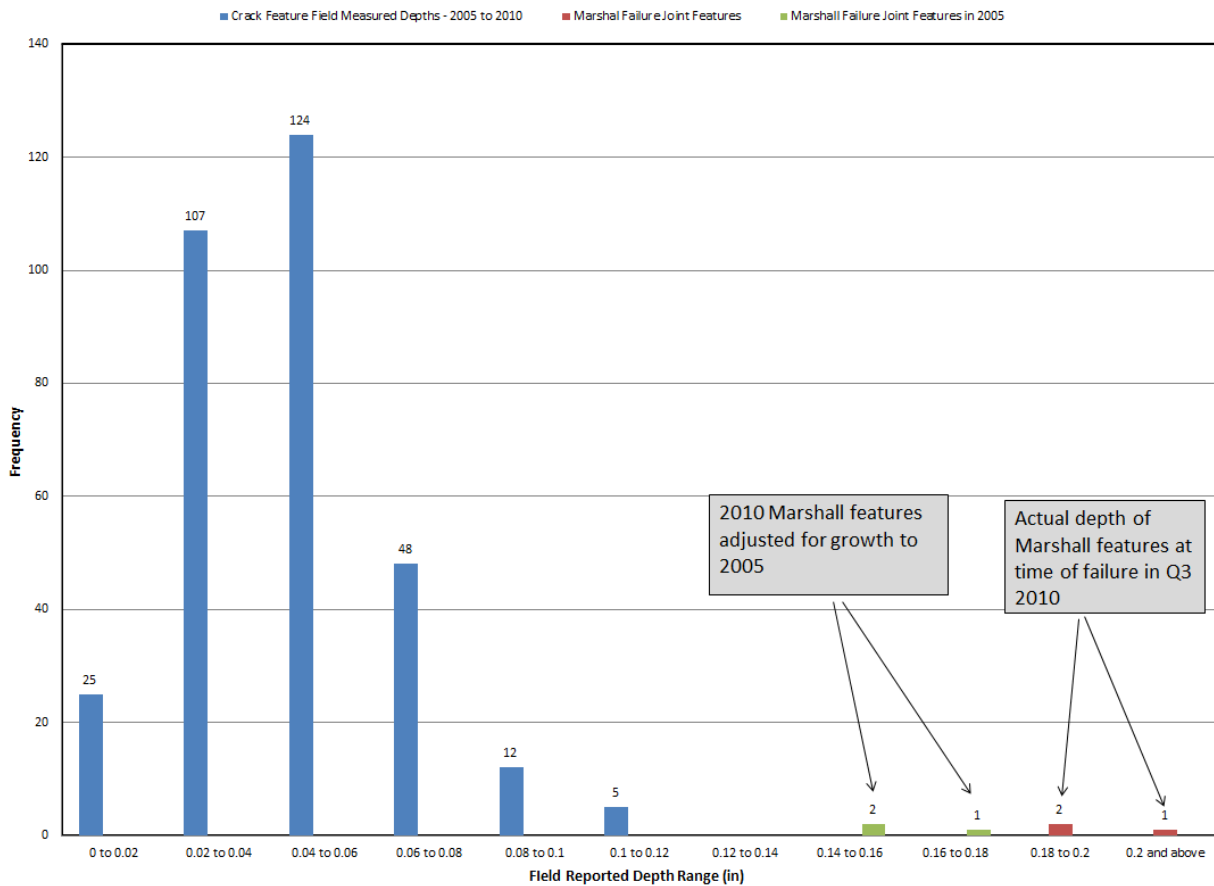
- Enbridge completed integrity digs and assessed features to achieve a statistically relevant data set to complete appropriate trending and calibration analyses and thereby supported the validity of integrity analysis conclusions and future integrity plans.
- The results of the trending and calibration analyses demonstrated that the USCD ILI tool was performing within the specifications provided by the ILI vendor for crack-likes and crack-fields. The measured Probability of Detection was 100% from data gathered through field assessments to-date. This result exceeded the Probability of Detection as stated in the USCD ILI reporting specification of 85% at reporting threshold. The Probability of Sizing met USCD ILI tool specification.
- Coincident corrosion did not appear to impact the ability of the ILI tool to size the features within the correct depth bucket.

Based upon the calibration results and crack growth rate analysis the re-assessment schedule was determined to be 2010, an interval of 5 years. This 5 year re-assessment interval was calculated to have a minimum factor of safety of two. In other words, using crack growth models developed and accepted by the industry, crack features were not expected to present an integrity threat for over 10 years. The application of a factor of safety of 2 in this case is an example where conservatism is designed into the integrity management program. The 2010 ILI assessment was underway at the time of the Accident.

To summarize Enbridge's crack inspection and integrity dig program on Line 6B in 2005-2010, it was a program conducted in compliance with industry standards and PHMSA regulations and integrated recognized approaches to investigate the accuracy and performance of the USCD ILI tool. The integrity dig program and re-assessment interval determination was based upon statistically relevant trending and calibration results. Given this extensive information collection, calibration, integration and analysis, the July 2010 Marshall feature was not predictable.

Post-Accident Inspection and Analysis. Based upon the trending and calibration activities undertaken for the Line 6B crack ILI and dig program, all evidence suggested that the USCD ILI tool was accurately reporting the size of features. However, the Marshall feature significantly deviated from the trend and calibration results. The depth distribution for field assessed crack features is included in Figure 3 below:

Figure 3



The red bars show the depth of the Marshall features as found in 2010 and the green bars show the 2010 features, adjusted for growth, as they would have appeared in 2005. The estimated depths in 2005 have been calculated post-Accident using a linear time-averaged SCC growth rate of 0.15 to 0.2 mm/year. This value is considered to be a reasonable estimate based upon industry SCC growth rate ranges and the pressure cycling spectrum that occurred at the Marshall location between 2005 and 2010. The estimated depths of the Marshall features in 2005 (the time of the USCD inspection) are well in excess of any features identified in the ILI tool report or through the subsequent dig program. Based upon the trend and calibration analyses, there was no evidence to suggest that such a significant feature existed on the pipeline.

Following the Accident, Enbridge conducted numerous excavations on Line 6B in 2010 and 2011 to collect field assessment data on cracks associated with corrosion. The results from this dig program, based on 2010 USCD ILI data and summarized in Table 4, are similar:

Table 4

| | Sized Accurately or Conservatively | One tool tolerance (0.5mm) above depth bin | Two tool tolerances (1.0 mm) above depth bin |
|---|---|---|---|
| All Field Assessed Crack Fields(SCC) | 95% | 4% | 1% |
| Field Assessed Crack Fields Coincident with Corrosion | 93% | 6% | 1% |

The Marshall feature in 2010, as sized and documented in the NTSB Materials Report, is calculated to be approximately 7 tool tolerances greater than the maximum 2005 ILI reported depth.

When available, it is possible to overlay the metal loss ILI and crack ILI data sets to identify those features that are coincident. Once established, an operator could choose to add the ILI data in a quantitative process in order to establish and implement an integrity dig program. An example of this process is included below and its efficacy evaluated using Line 6B data from 2010 and 2011. The features referenced in Table 5 are those that were excavated and assessed in the field and thereby provide direct comparative evidence.

Table 5

Adding the ILI reported depth of the crack with a tool tolerance to the ILI reported depth of the metal loss

| | Crack Depth Bracket | | | | >100% WT | No Cracking Found (e.g. Metal Loss) |
|--|---------------------|------------------|------------------|---------|----------|-------------------------------------|
| | <0.040" | 0.040" to 0.080" | 0.080" to 0.120" | >0.120" | | |
| Field Assessment Data | 64 | 84 | 21 | 0 | 0 | 444 |
| Prediction Using Adding ILI Data Process | 0 | 0 | 13 | 570 | 30 | N/A |

As Table 5 shows, in over 600 features found in the field there was no feature greater than 0.120" depth. Adding the data together in Table 5 would result in almost all of the features having depths over 0.120". Adding the data together as shown in Table 5 predicted that 30 features would be 100% through-wall and require immediate mitigation actions. Field assessment results, however, demonstrated that all features were less than 0.120 inch (48%) through-wall. When assessed in the field, the majority of features (444 of 613) were corrosion with no cracking. Based on these results, adding the data together as shown in Table 5 is not a suitable engineering integrity process for Line 6B.

To summarize, trending integrity dig information from both 2005 and 2010 USCD programs demonstrates that corrosion coincident with cracking appears to have no notable impact on the crack depth estimate. Simply adding ILI reported corrosion depth to ILI reported crack depth has been shown to yield overly conservative and unreasonable results.

In order to capture a broader pipeline industry perspective on ILI detection and characterization of cracking coincident with corrosion, Enbridge retained Quest Integrity Group (“Quest”) to provide an expert third party report (incorporated herein as Attachment A). Quest identified that implementation of a quantitative approach for engineering assessments of coincident cracking and corrosion as reported in ILI data integration processes is not trivial and has not been formalized within industry.

Pipeline Integrity Inspection, Technology and Analysis Conclusion. The foregoing post-Accident review and analysis indicates that the crack inspection and mitigation program that Enbridge undertook from 2005 to 2010 on Line 6B was in compliance with industry standards and regulations and that the feature that caused the loss of containment at Marshall was an anomaly that was not reasonably predictable using industry leading inspection and repair technology.

Additionally, key results from calibration activities demonstrate that the ILI data met the in-line inspection tool specifications and that complex features such as cracking coincident with corrosion were appropriately integrated into the calibration activities.

5. ENBRIDGE’S ORGANIZATIONAL RESPONSE TO THE ACCIDENT

Along with a root cause investigation, Enbridge conducted a comprehensive cross-functional self-examination following the Accident. As a result of Enbridge’s experience in responding to this Accident, the comprehensive investigation and self-examination of its pipeline integrity processes and management systems and the NTSB’s investigation, Enbridge implemented a number of additional measures, procedures and process modifications that have collectively already significantly reduced and will continue to reduce the risk of a loss of containment, improve its monitoring of and responding to alarms in the control room and strengthen its response to leaks and releases. Many of these modifications and improvements include ongoing review and improvement mechanisms that will promote increased preparedness and strengthen Enbridge’s management systems.

In addition to the measures implemented in Enbridge’s integrity inspection and analysis program discussed previously, other significant measures are described below.

Pipeline Control Systems and Leak Detection (PCSLD)

- A. Enbridge has, for over 60 years, worked to be at the forefront of pipeline control and leak detection technology, and has pursued this goal with technical personnel in various organizational structures. In October 2010, Enbridge pulled these functions together and created the PCSLD department, which is Director-led and reports to a Vice President. This establishes a single area of accountability in relation to leak detection capability, safe and reliable pipeline control systems and improved operator information systems. Staff and contractor additions in 2010-2012 resulted in a doubling of the PCSLD workforce. Enbridge created three sub-departments under the PCSLD department: (i) the Leak Detection sub-department which is comprised of three teams: Maintenance and Integration, Assessment and Support and Testing and Research; (ii) the Pipeline Control Systems sub-department which is comprised of three teams: SCADA Services, Control Systems CAN and Control Systems USA; and (iii) the Quality and Compliance sub-department.

- B. Four Leak Detection Analyst procedures have been implemented since July 2010: the leak detection escalation process; shift change sheet; alternate leak detection recommendation procedure; and analysis and communication procedure. Procedures for the new Control Room Management regulation are to be implemented by August 2012. Enbridge also established a Quality Management System (QMS), with a view to more effective execution of work activities meeting pre-defined quality objectives.
- C. The Leak Detection Analyst Training Program has been enhanced in several areas including on-the-job training, training program layout, readiness assessment and communications with CCO Personnel.
- D. Leak Detection System Changes: Continuous improvement plans have been developed and are being implemented to tune the Leak Detection Systems for optimal performance. A leak detection equipment design standard has been developed to ensure leak detection performance standards will be met on new pipelines. Research initiatives are underway to assess commercially available leak detection technologies and to determine if there are complementary strategies to further enhance leak detection performance.
- E. Leak Detection Instrumentation: Assessments and planning of instrumentation additions and upgrades required to improve the performance of the leak detection system, and ensure it consistently meets or exceeds Enbridge internal performance targets have been completed. A Leak Detection Instrumentation Improvement Program has been initiated that will add and upgrade instrumentation across the system based on the assessment results. The establishment of a maintenance management program is underway. This program will further enhance the existing program by formalizing the inventory and management of critical leak detection equipment.
- F. SCADA/Pipeline Control System Changes: Initiatives are underway to seek to improve controller decision support systems. This includes active projects which will deliver tools to support the analysis of column separation as well as potential leak events, and implementation of incremental expert systems to support alarm analysis. On-going improvements to historical data storage and retrieval have been completed at most terminal and pump stations, resulting in the archiving of high consequence data at a resolution frequency of approximately one second. Evaluation of the current communication mechanisms, including RTU infrastructure and physical communication layers, is in progress.

Pipeline Control (including Control Center Operations)

- G. To better align, focus, manage span of control and workloads, Pipeline Control now reports to Operations rather than to Customer Service in the previous reporting structure. Enbridge created a new Vice President for Pipeline Control. Enbridge added ten new Senior Technical Advisors to support abnormal operating conditions and on-going mentorship. Training, engineering and Control Center operator staff has been augmented. Seven new operator positions were added in the last year to accommodate growth and expansion, reassignments, replacements and workload balancing.
- H. Key Procedures and Process Enhancements. Enbridge has revised and enhanced many procedures seeking to improve communication and decision making, including

procedures for handling pipeline start up and shutdown, Leak Detection System alarms and communication protocols and suspected column separations (Enbridge developed an analysis form and a list of common column separation locations). Enbridge also revised and enhanced its procedure review and revision process and developed a pipeline control administration on-call handbook and specific Life Saving Rules for the CCO.

- I. Control Room Management (CRM) – 49 C.F.R.195.446. The Control Center’s CRM Plan was revised, updated and in place August 1, 2011 to meet the requirements of this recently promulgated rule. It consists of detailed processes and procedures to provide control room management in the following areas: roles and responsibilities; provide adequate information – SCADA; provide adequate information – shift change; fatigue mitigation; alarm management; change management; operator experience; training; compliance validation; and compliance and deviation. A number of the sections were implemented in October 2011 with the remaining on track for implementation by August 2012.
- J. Training Development and Enhancements. All pipeline operators have received enhanced hydraulics training which included the following: a re-emphasis on the need to think leak first and adhere to emergency procedures, an overview of MBS system and procedures, refresher training on the “10-minute rule” and compliance to procedures, clarification of the roles and responsibilities between operators and shift lead as well as between operators/shift leads and MBS Analyst, column separation analysis, incident investigation (including SCAT) for all Managers, Technical Services, Engineers, Shift Leads and Training Staff. Other training includes Lifesaving Rules and Respectful Workplace Training for all Pipeline Control Staff; augmentation of Emergency Response Training in the Control Center to include two full days in 2012; Fatigue Management Training; Mentor Selection Process and Training; MBS System Training and Formalized Communication Protocols; and on-call training for Pipeline Control Administrative staff.

Public Awareness

- K. At the time of the Accident Enbridge had a well-established ongoing Public Awareness Program and had recently provided a safety awareness training program to both Marshall fire departments. In an attempt to further enhance the effectiveness of this program, in May 2011 Enbridge established a U.S. Public Awareness Committee consisting of internal stakeholders including field operations and management, right-of-way, compliance, integrity and public affairs, and meets four times annually. The committee is tasked with (a) maintaining effective communications with other stakeholders; (b) preparing for successful regulatory inspections and audits; (c) implementing standardization of organization wide programs; (d) an annual review and sign-off of the Public Awareness Program; (e) an annual Review of the Public Awareness Performance Measures; (f) reviewing Industry best practices; (g) achieving full participation among the committee members; and (h) establishing accountability and consistency.
- L. A Public Awareness Documentation Database, which is accessible online by all Enbridge U.S. employees, has improved the documentation of supplemental Public Awareness contacts, including face-to-face meetings, letters, emails, telephone calls and events. Improvements since the roll out of the database in 2010 have been based on user experience and are focused on continuous improvement of our documentation process.

- M. Training is provided annually for field employees in each liquids region and gas district to help them better understand their role in the Public Awareness Program. In 2011, Enbridge provided additional training for more than 500 field employees. In Q4, 2012, online training will be rolled out for all employees to complete, regardless of whether they work in a field location or in an office. In addition, a program to provide in-person and online training for third party emergency responders in Enbridge's areas of operation is currently in development and will launch in Q4, 2012. The training will cover emergency preparedness communications, potential hazards and other relevant topics.
- N. Focus group testing of the Public Awareness brochures for all audiences was conducted in Q1, 2012. Based on the feedback received from participants, several changes were made to the 2012 brochures. Major changes include re-focusing emphasis placed on the emergency numbers and reducing non-emergency phone numbers to one toll-free number to improve clarity on which number to call in emergency vs. non-emergency situations. The entire "Affected Public" (as defined by applicable regulations) audience now receives a magnet with the annual brochure mailing which includes the appropriate emergency number for their area. Through the engagement of Enbridge's Government Affairs team, the public official mailing list has been improved to better target state and federal public officials. In addition, supplemental mailings have been sent to public officials to remind them of Enbridge's Public Awareness efforts, including 811 Day, National Safe Digging Month and the delivery of Public Awareness calendars to their constituents.

6. CONCLUSION

On July 25, 2010, Line 6B was operating normally when experienced Enbridge control room personnel shut it down to facilitate a routine scheduled delivery into Stockbridge. Enbridge utilized state-of-the-art testing on Line 6B, particularly in the six years prior to the Accident, and has approximately 60 years of experience operating what today is North America's longest liquids pipeline delivery system. Enbridge had no reason to expect a failure of Line 6B.

Because a significant loss of pressure is normal during a shutdown, the experienced crew in the control room misinterpreted the significance of alarms and thus focused their trouble shooting over the next seven hours on resolving the alarms, not addressing a potential loss of containment. Moreover, notwithstanding multiple 911 reports of petroleum odors in the area, an active public awareness program and investigations by two separate fire departments, Enbridge was not contacted and the existence of the failure was not identified for over 17 hours.

Once Enbridge was advised that oil had been spotted in Talmadge Creek, Enbridge management responded swiftly and decisively at the highest levels. The CEO was on the scene before the day was over, and spent the next two months overseeing the organization's extensive response efforts. He took full responsibility, pledging that Enbridge would address the impacts of the release on the natural environment and would address the financial and other needs of individuals and businesses in the community. Enbridge is doing so still today. The crude oil has been virtually all cleaned up and product has continued to flow through Line 6B since September 2010.

Enbridge believes that its pipeline integrity process and management in 2010 were state of the art and in compliance with all applicable regulatory requirements. However, it now, with

the benefit of the reviews of the Accident, appreciates the limits of what it and the industry knew then, and what it might have been able to do differently in order to identify the potential problem in advance. Enbridge has learned from this Accident and has implemented a number of measures that will help Enbridge and the industry prevent the recurrence of accidents like this one in the future. Enbridge remains committed to operating to high standards and to avoiding releases.

Attachment



Detection and Characterization of Coincident Cracking and Corrosion
Utilizing Ultrasonic Shear Wave Inline Inspection Technology

Prepared for: Mr. Sean Carey

Privileged and Confidential to: Designated Client Representatives

Project Number: 102913

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1 Executive Summary

Enbridge Pipelines, Inc. (Enbridge) has retained Quest Integrity Group (Quest Integrity) to provide an independent review of the fundamental abilities of inline inspection (ILI) ultrasonic shear wave crack detection (UTCD) technology. Specifically, Enbridge is interested in the detection and characterization of coincident cracking and corrosion features utilizing UTCD technology.

Information presented in this report are based on the author's 19 years experience in the ILI industry¹, published technical papers, current regulations/standards/best practices and proprietary ILI reports provided by Enbridge.

Since 1999, data integration has been a primary component of integrity management programs. More recently, focus has been placed on interactive threats. Current regulations, standards or best practices however do not prescriptively address anomaly response plans as related to coincident cracking and corrosion reported in an inline inspection.

In accordance with current standards, Enbridge incorporates threat integration, trending, fitness for purpose and continual improvement as core components in the management of ILI data.

Enbridge currently addresses the integrated threat of cracking and corrosion qualitatively with the analyses of trending results and adding calibrated tolerances to the upper range of reported crack-like and crack field depths.

Implementation of a quantitative approach for engineering assessments of coincident cracking and corrosion as reported in ILI data integration processes is not trivial. There is not one approach that is appropriate for all scenarios as experiences differ between pipeline operators and possibly between inline inspections for the same operator. Industry support, technical studies and innovative engineering may result in a single common approach that requires standardized feature characterization, drive data analysis improvements or motivate the introduction of new crack detection ILI technology.

¹ Lisa Barkdull's CV is provided in Appendix A

2 Fundamental Abilities

The primary focus of this document is the detection and characterization of coincident cracking and corrosion utilizing ultrasonic shear wave crack detection inline inspection technology. Prior to this specific discussion, fundamental abilities of ultrasonic shear wave technology as applied to ILI are presented in Section 2. This information is typically general knowledge and has been presented in multiple papers. Specific discussions of coincident cracking and corrosion begin in Section 3.

Since the mid 1990's, numerous experiences have been shared at industry conferences and meetings describing how UTCD ILI tools have successfully inspected pipelines for the detection and characterization of crack-like and crack field features. Continual feedback between pipeline operators and ILI service providers has driven improvements in technology and data analysis protocol.

While innovative improvements have been made in tool design, electronics and analysis techniques over the past 15 years, the fundamental physics of the technology has remained the same.

UTCD ILI tools employ pulse-echo transducers where the same sensor is used to both transmit a sound wave and receive a return signal. Typically, sensor configuration is designed such that an optimal angle of refraction is 45° . Using Snell's Law calculations, an angle of incidence is selected for the longitudinal wave in the coupling medium such that the resulting shear wave in the pipe wall is transmitted at 45° . For UTCD ILI tools with fixed angle transducers, the resulting angle of refraction may not be exactly 45° due to variability between various coupling mediums found in different pipelines. There may be cases where it is determined that 45° is not the optimal angle of refraction (due to a target feature characteristic) and the angle of incidence is selected such that the resultant angle of refraction is optimized. For this discussion, the optimal angle of refraction is considered to be 45° .

This optimal angle results in the strongest corner effect reflection, the reflection at the interface of the crack with the internal or external surface of the pipe. An optimal reflection results in more consistent depth predictions. Figure 1 illustrates the corner effect reflection [1].

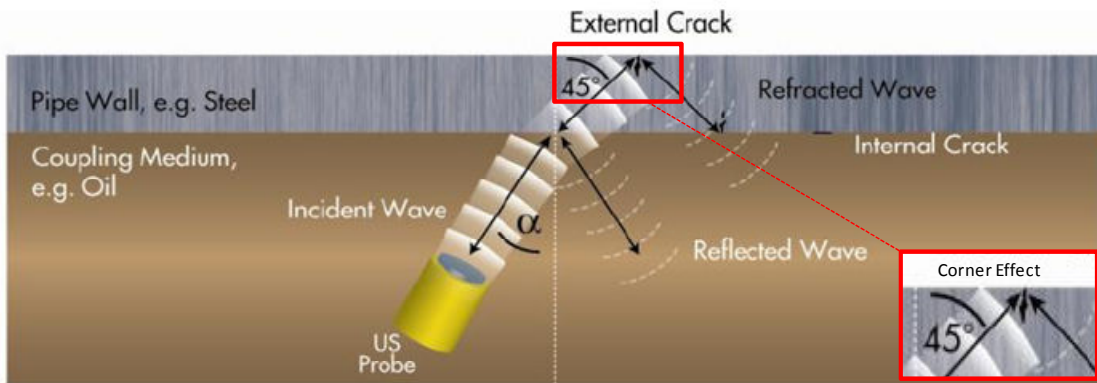


Figure 1: Corner Effect for External Crack

2.1 Detection and Characterization

Appendix C of 49 CFR Part 195 recommends crack detection inline inspection tools for the detection of cracks and crack-like features including stress corrosion cracking (SCC), fatigue cracks, narrow axial corrosion, toe cracks, hook cracks, etc. [2]. UTCD ILI tools do not require volumetric anomaly characteristics and therefore are particularly efficient at detecting tight cracks such as SCC.

Unlike other NDE ultrasonic technologies applied in the ditch, there is typically not a time-of-flight measurement between the external or internal surface of the pipe to the crack tip when using UTCD ILI technology. The corner effect reflection is the primary reflection used for depth predictions of crack-like and crack field features. Although it is an indirect measurement, the amplitude response from the corner effect reflection correlates well with feature depths, as seen in the example in Figure 2 [1].

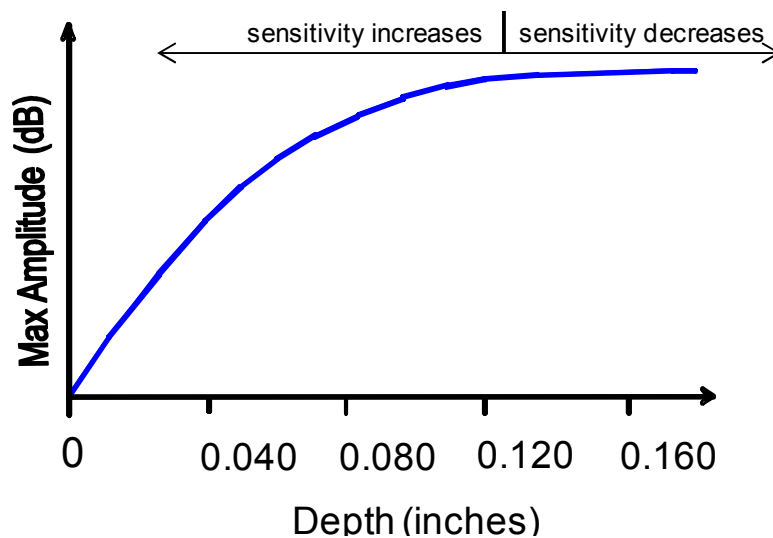


Figure 2: Amplitude Response as Depth Increases

Using the ultrasonic physics previously discussed, detection and/or characterization using the corner effect reflection could be affected if:

- the angle of refraction varies from optimal
- the axial orientation of the feature varies more than $\pm 10^\circ$ or the radial orientation varies more than $\pm 10^\circ$ to 45°
 - limits on axial and radial orientation are typically defined in tool performance specification sheets
- the internal or external surface of the pipe causes a non-perpendicular interface
 - the crack is within a corrosion region
 - the crack is within the vicinity of a geometric feature such as a weld

Smooth-edged low-level corrosion potentially associated with crack fields [3, 4] will likely not have a negative impact upon reflection amplitude.

- the reflection resulting from sharp edged corrosion or a geometric feature has higher amplitude and is used as the amplitude for a crack-like or crack field feature, resulting in false positive classification (i.e. crack field classification when found to be corrosion) or in conservative depth range predictions
- there is not a corner effect reflection as in the case of a mid-wall crack

2.2 Analysis and Reporting

One of the challenges associated with UTCD ILI technology is the classification and characterization of features. Differentiation must be made between extraneous reflectors and crack-like or crack field reflectors. Extraneous reflectors can result from geometric features such as long seam welds and from impurities or manufacturing anomalies in the pipe wall. Low level metal loss and crack fields in addition to pipeline impurities such as inclusions can look similar in UTCD ILI data.

Feedback from pipeline operators and increased training and experience of ILI analysts, recently reinforced by standards such as API 1163 In-line Inspection Systems Qualification Standard (API 1163) and ASNT Inline Inspection Personnel Qualification and Certification (ILI PQ 2005), provide for continual improvement in both technology and analysis protocol [5,6].

Automated processes are used to differentiate potential reflectors from base material in the analysis process. Ultimately however, feature classification and characterization are finalized by qualified human experts in accordance with standards such as ILI PQ 2005.

The data analysis process requires a blend of objective feature attribute extraction and subjective visualization skills (in the form of human expertise). Feature attributes include maximum amplitude, time-of-flight, spatial overlap, length and width. Apart from feature attributes, accurate depth characterization is also a function of correlation between multiple sensors and signal interpretation. Due to potentially large data sets, time tables for the delivery of a final report are typically longer for UTCD inspections than for other ILI technologies.

Traditionally, crack-like and crack field features are characterized by a depth distributed over the entire length.

Depth is presented in the form of a depth range due to the indirect measurement methodology (i.e. corner effect and not typically crack tip) and potential for variability between the reflection amplitude and anomaly depth.

Definition of the depth range is typically defined by the service provider and consideration of the pipeline operator’s reporting requirements. Table 1 details several examples of depth ranges.

| Est. Depth as % WT | Est. Measured Depth (ex 1) | Est. Measured Depth (ex 2) |
|---------------------------|-----------------------------------|------------------------------------|
| < 12.5% | < 40 mil | < 40 mil |
| 12.5% - 25% | 40 – 80 mil | 40 – 80 mil |
| 25% - 40% | 80 – 160 mil | 80 – 120 mil |
| > 40% | > 160 mil | > 120 mil |

Table 1: Reported Depth Range Examples

If an estimated depth as % of wall thickness (WT) is used, there should be consideration of applicability to nominal wall thickness. For example, if the nominal wall thickness is 0.750”, a depth of 25% WT is approximately 187 mil. This is likely outside of the tool’s resolution capabilities due to ultrasonic saturation. Likewise, if the nominal wall thickness is 0.188”, a depth of 12.5% is approximately 23 mil. This is below the reported detection capabilities of the tool.

Two service providers that this author is aware of use estimated measured depth (ex 1). Depth ranges are supported by expected corner effect reflections. As seen in Figure 2, the crack depth-to-amplitude response is more sensitive for smaller depth cracks. The relationship between amplitude and depth becomes more difficult to discriminate as the depth of the feature increases; as the crack depth increases on the x-axis, the amplitude response becomes less sensitive on the y-axis. This is the motivation for a lower depth range of 40 mil (40 – 80 mil) and a higher depth range of 80 mil (80 to 160). The amplitude change for both ranges is approximately 6 to 7 dB.

When considering the conservative methodology of assuming crack-like or crack field depth to be the upper limit estimate, estimated measured depth (ex 2) aligns itself better

for prioritization of features. This range correlates well with the estimated depth as % WT ranges when the wall thickness is 0.300". Modeling and excavations can be used to support this depth range delineation.

3 Anomaly Response Plans

For the purpose of this document, anomaly response refers to prioritizing anomalies reported as a result of an inline inspection; not crack-like or crack field features validated in the field.

While prioritization guidelines utilized by ILI service providers and liquid pipeline operators for metal loss and deformation inspections are most often motivated by regulatory definition in section 195.452 (h) (4) of 49 CFR 195 [2], prioritization guidelines for features reported after a UTCD ILI can differ between pipeline operators.

In many cases, the ILI service provider will only provide depth ranges; subsequent engineering assessments to assist in prioritization are handled by the pipeline operator or engineering companies contracted by the pipeline operator. Expert judgment resides with the pipeline operator in the development and implementation of mitigation and remediation plans.

The following examples are cursory in nature and relate to past experiences as an ILI service provider. They do not represent all anomaly response plans nor do they take into account growth mechanisms for crack-like and crack field anomalies. Specific anomaly response plans are typically defined by the pipeline operator or an engineer company contracted by the pipeline operator.

- Critical length tables

Using the NG-18 In secant or similar approaches such as CorLAS(TM) [8], critical lengths for the upper bound of depth ranges (i.e. 80 mil for the 40 – 80 mil range) are established prior to the inspection. These tables can be used as guidelines for populating severity lists in the ILI report. Inputs include pipe OD, nominal wall thickness, MAOP, and an estimation of toughness properties in base material and in the long seam. Relative position of the anomaly, such as in base material or at long seam, is typically reported by ILI service providers. The resulting table may look something like Table 2. Reported lengths of crack-like or crack field features are compared to critical lengths for response planning.

| 20" OD, 0.250" Nominal WT, X52, CVN 10 ft-lbs long seam | | | | |
|---|----------|-------------|--------------|-----------|
| Crack Depth | < 40 mil | 40 – 80 mil | 80 – 160 mil | > 160 mil |
| Critical Length | na | 30" | 2" | all |

Table 2: Example Critical Length Table

- Failure Assessment Diagram (FAD)

Likewise, critical flaw sizes can be established using the API 579 2007 Level 2 FAD [8] approach. For a particular crack size of length $2c$ and depth a , a load ratio (L_r)– toughness ratio (K_r) point is computed and plotted on the FAD. A point falling under the limiting curve is considered acceptable or safe. A point falling on the curve is considered critical [9]. Figure 4 shows a sample FAD. As with other anomaly response protocol, depth is typically taken as the upper bound of the reported depth range and length is the reported length.

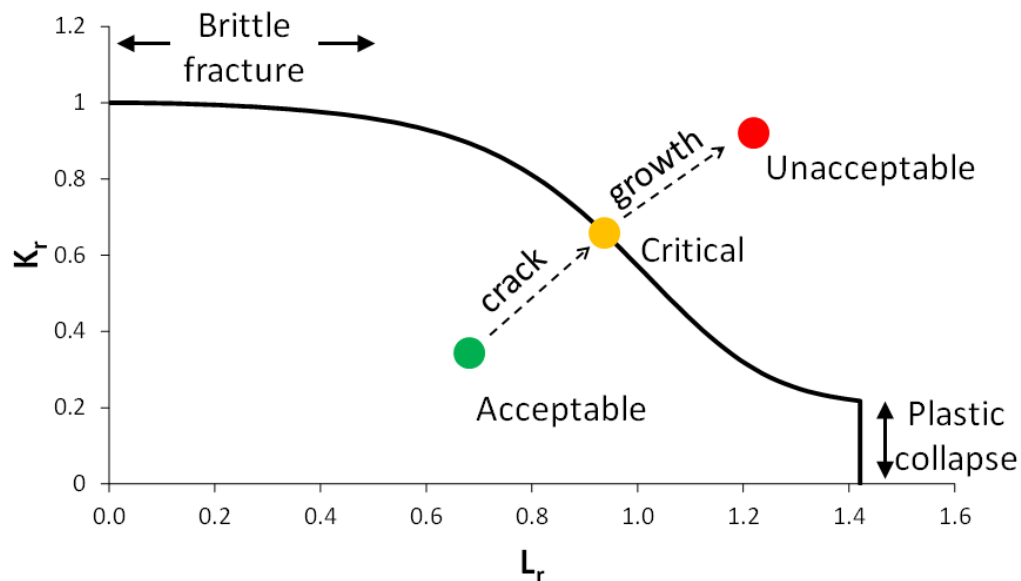


Figure 3: Sample FAD

- Failure pressure calculations

Failure pressure calculations may be computed after analysis is completed using critical crack assessment models. Typically, the upper bound of the depth range and the reported anomaly length are used in the calculation.

As discussed, depth for crack-like and crack field features is presented in the form of a depth range due to the indirect measurement methodology and potential for variability between the reflection amplitude and anomaly depth. Some operators, such as Enbridge, have experienced that using the upper bound of the depth range provides a conservative estimate of anomaly depth to be used in critical crack assessment models. This experience comes in the form of continual comparative analyses between ILI reported depths and excavation measurements.

Historically, there has not been a specific technique defined for quantitatively integrating reported metal loss from an inline inspection with coincident reported crack-like or crack field anomalies from an inline inspection for the purpose of implementing critical crack assessments for anomaly response plans. Qualitatively considering coincident features, Enbridge has historically found that excavation measurements demonstrate the upper bound of the reported depth provides conservatism such that the crack and corrosion depth found in the field are typically less than the reported upper bound.

3.1 Regulations, Standards and Best Practices

Since 1999, data integration has become a primary component of pipeline integrity management. Specifically, there has been a large amount of research and regulatory response concerning dents that are coincident with metal loss, cracking or stress risers. However, there is little industry guidance on developing an anomaly response plan for crack-like or crack field features associated with metal loss.

API 1163 and NACE SP0102-2010 [10] are standards specifically written for inline inspections. Table 1 in SP0102 identifies types of ILI tools and associated inspection purposes. Ultrasonic shear wave crack detection ILI tools are identified as being able to detect² and size³ metal loss. The ability to detect metal loss with a UTCD ILI tool is repetitively demonstrated in ILI reports and/or subsequent excavations.

As specified in SP0102, sizing metal loss is defined by the sizing accuracy of the tool. Anomaly sizing accuracies are typically specified in performance specification sheets. Section 7 of API 1163 defines the requirements to qualify performance specifications. “Performance specifications shall define, through the use of statistically valid methods, the ability of the in-line inspection system when run in a specific pipeline to detect, locate, identify, size pipeline anomalies, components, and features. An in-line inspection system may be capable of addressing more than one type of anomaly or characteristic during an inspection run. If so, the performance specification shall address each type of anomaly or characteristic.” Performance specifications for UTCD ILI tools do not typically include sizing accuracies for metal loss or cracking in metal loss, implying that statistically valid methods have not been implemented by the service provider for the purpose of

² Limited by the detectable depth, length, and width of the indication

³ Defined by the sizing accuracy of the tool

quantitatively differentiating ultrasonic reflectors in the presence of cracking, corrosion, and coincident cracking and corrosion. Thus, while API 1163 recommends a performance specification for coincident deformations with metal loss, it does not have a similar recommendation for cracking and metal loss.

API 1163 supports the use of verification measurements from previous runs of an in-line inspection system to further understand performance capabilities. “Verification measurements are dimensions and characteristics that have been physically measured after anomalies have been exposed.” In Enbridge’s experience, excavation measurements have shown that the upper bound depth of the reported crack-like or crack field feature is typically conservative whether a crack or coincident cracking and corrosion features are found in the field.

ASME B31.4 does not address anomaly response planning (anomalies reported as a result of an inline inspection), but does allow for engineering critical assessment by the pipeline operator when determining a remediation approach if a crack is found during a field excavation.

API 579 Part 9 [11] address assessment of crack-like flaws. Section 9.9 defines t as “thickness of a component containing the crack-like flaw including metal loss and future corrosion allowance, as applicable”. While API 579 Level 2 does include uniform metal loss and future corrosion allowance as part of the assessment, the recent PRCI report Pipeline Defect Assessment L52314 [8] states that “For pipeline defect analyses, these factors typically can be ignored because they are not relevant with respect to most line pipe situations.” This conclusion does not reflect Quest Integrity’s opinion. If there is significant wall thinning below nominal, we believe that the actual thickness should be used in the assessment, as per API 579. Future corrosion allowance is typically not included.

49 CFR 195 195.452 prescriptively defines anomaly response plans for dents with indications of metal loss, cracking or stress risers but does not prescriptively address coincident cracking and metal loss.

3.2 Anomaly Response Plans for Coincident Cracking and Corrosion

Although there is little industry guidance or technical studies concerning anomaly response plans for coincident cracking and corrosion⁴, integration of multiple ILI data sets has proven effective in the management of pipeline integrity. There is value in the integration of crack detection and metal loss inline inspections, at least from a qualitative view point. For example, assessing corrosion with traditional methodology such as B31G is no longer applicable in the presence of cracking.

⁴ As reported in UTCD and metal loss inline inspections

The converse is not as clear. One can assess the crack-like or crack field anomaly using established methods but how is corrosion implemented into the assessment? This author has not seen an integrated crack detection – metal loss ILI report that quantitatively compounds crack depth and corrosion depth; nor a resulting critical crack assessment. This may be due to the fact that it is typically low level corrosion associated with crack-like and crack field features and the slightly thinner wall thickness has little impact on the resulting assessment. Additionally, it is possible that experiences show the depth range methodology of characterizing anomaly depth captures ultrasonic reflection variability that may be the result of coincident cracking and corrosion.

As seen in Figure 4, reported UTCD ILI crack-like and crack field depths trend and on average are conservative when compared to coincident crack and corrosion measured depths in the field. This information is compiled from verification measurements of known coincident cracking and corrosion provided by Enbridge⁵.

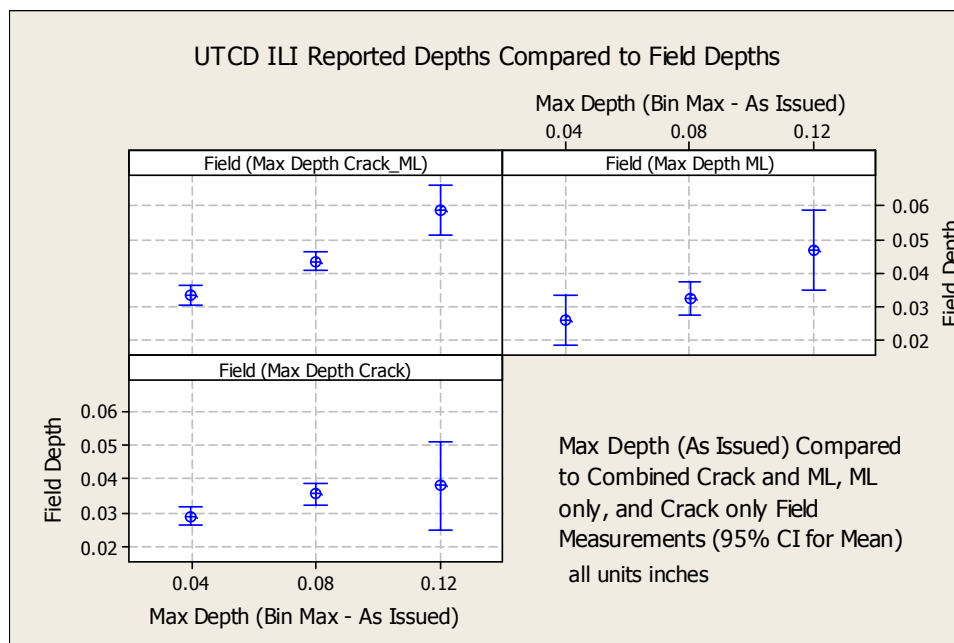


Figure 4: Maximum Depth from UTCD ILI Bin Range Compared to Field Measurements

In reference to question 7.19 of PHMSA Frequently Asked Questions concerning the Hazardous Liquid IMP [12], tool tolerances for UTCD tools at an 80% certainty are typically within the depth range (i.e. the upper bound depth represents the upper limit for tolerance) or are within a minimal range of the upper bound (i.e. 16 mil). These tolerances could be applied to the estimated crack depth when implementing critical crack assessments. Other approaches for implementing UTCD tool tolerances include using empirical cumulative distributions based on excavation information for each depth

⁵ See Table 3 page 14: 2010 | Cracks in Corrosion Trending | ILI data, field data

range and using a specified percentile for the representative depth of that range. This is a useful method when experiences demonstrate that field measurements are trending deeper than reported depths. Comparison of ILI results and field excavations can help establish the best approach for integrating tolerances into the model. UTCD ILI and metal loss ILI tool tolerances can be qualitatively considered using data integration and ongoing comparative analyses between the upper bound of the reported depth range and verification measurements for coincident cracking and corrosion.

For the purpose of discussion, several possible approaches on how to integrate crack-like and crack field features coincident with corrosion for a critical crack assessment are presented in Appendix B. Dependence on the conservatism of the approach and on the UTCD ILI's ability to differentiate crack depth from combined crack and corrosion depth will guide qualitative or quantitative consideration of tool tolerances.

Any model that becomes saturated with conservatisms compounded on one another loses the ability to address existing threats in a timely manner. One option to address all uncertainties with confident conservatism is to move from a deterministic model to a probabilistic model.

4 Line 6B

Line 6B is a 292.62-mile pipeline that originates in Griffith, Indiana and terminates in Sarnia, Ontario; primarily transporting heavy crudes. This line was constructed in 1969 using 30-inch diameter, X52 grade pipe with a nominal wall thickness of 0.250-inches. Approximately one-third of the pipeline is manufactured using a flash welded (FW) process and approximately two-thirds of the pipeline is manufactured using a double submerged arc welded (DSAW) process. The pipeline is externally coated with polyethylene tape.

Enbridge has provided Quest Integrity with relevant documentation from the following inline inspections:

| Year | Inspection | Document |
|-----------------------|---|---|
| 2010 | GE USCD GT-SK | PDF report |
| 2010 | GE USCD SK-RW | PDF report |
| 2010 | GE DUO SK - RW | PDF report |
| 2010, 2007, 2009,2010 | Crack Assessment Sheets: Enbridge integration of CD, MFL, WM, and AFD | ILI data, threat integration, FFS |
| 2005, 2010 | Trending Sheets: CD, field investigation | ILI data, field data |
| 2010 | Cracks in Corrosion Trending | ILI data, cracks in corrosions, field data |
| 2010 | Threat Integration | Example |
| 2005 | GE USCD GT – RW | PDF Report |
| 2005, 2004 | Threat Integration: CD, WM | Example |
| NA | NA | Line 6B general information |
| 2006, 2007 | Field | Example NDE |
| 2010, 2011 | Field | Example NDE |

Table 3: Line 6B Documentation

4.1 Overview of Crack Detection Inspections

An ultrasonic crack detection (UTCD) inline inspection of Line 6B from Griffith, Indiana to Sarnia, Ontario was performed in December 2005. Another ultrasonic crack detection inline inspection was performed in October 2010 for the entire segment, using phased array technology. In November of 2010, two more traditional ultrasonic crack detection inline inspections (referred to in this report as UTCD) were performed from Griffith to Stockbridge and Stockbridge to Sarnia.

From November 2010 to present, over 5788 verification measurements have been performed. Per API 1163, Enbridge uses this information to compare reported and measured anomaly characteristics for the purpose demonstrating tool performance, building an understanding of the relationship between ILI reported and field measured anomaly characteristics, and provide feedback to the service provider as part of the continual improvement process.

4.2 Trending

Comparing reported and measured anomaly characteristics, referred to as trending, is a core part of Enbridge's management of ILI data. As a result of historical and ongoing excavations, Enbridge has established that ILI reported metal loss⁶ features have been found to be SCC in the field. Likewise, ILI reported crack-like and crack field features have found to be corrosion in the field.

⁶ Reported as a result of UTCD ILI analysis

The following trending only considers those crack-like and crack field features that are known to be associated with corrosion.

Figure 5 is a boxplot⁷ that illustrates the trending results of 356 reported crack-like and crack field upper bound depths as compared to field measured depths (crack depth and corrosion depth combined). On average, a conservative trend is demonstrated; with the largest conservatism in the higher depth range and the least conservatism in the lower range. In order to address uncertainty in the ILI data, tool tolerances were added (using outliers as a consideration) and trending results were incorporated as part of Enbridge's management of ILI data. Table 3 outlines reported anomaly depths that are currently used in fitness for purpose (FfP) assessments to address crack-like and crack field threats on Line 6B and Figure 6 is an updated boxplot that illustrates the incorporation of tolerances.

⁷ Description of a boxplot graph is found in Appendix C

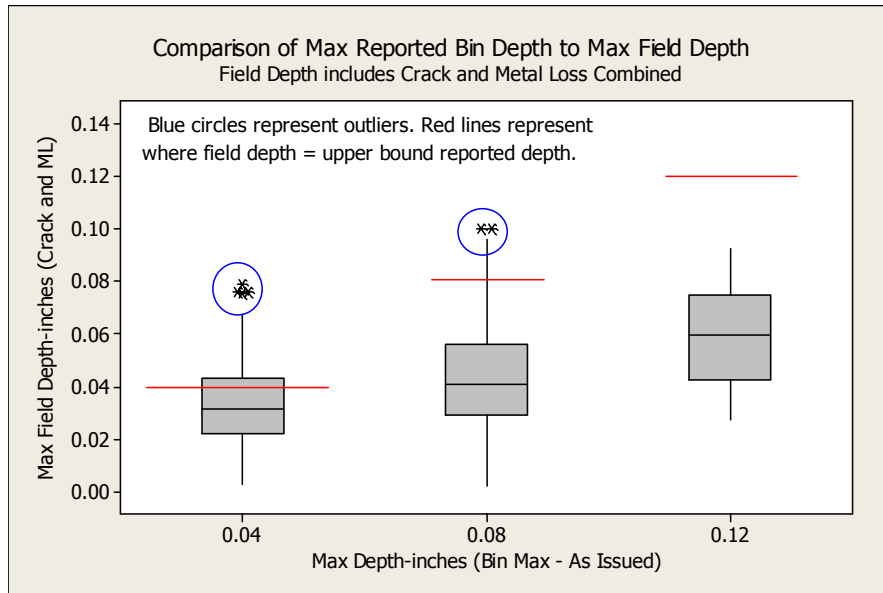


Figure 5: Trending of Coincident Cracking and Corrosion

| Reported Depth (inches) | Depth used in FfP (inches) |
|-------------------------|----------------------------|
| < 0.40 | 0.80 |
| 0.040 – 0.080 | 0.100 |
| 0.080 – 0.120 | 0.140 |
| > 0.120 | Meets dig criteria |

Table 4: Updated UTCD ILI Depth Characteristics used in FfP

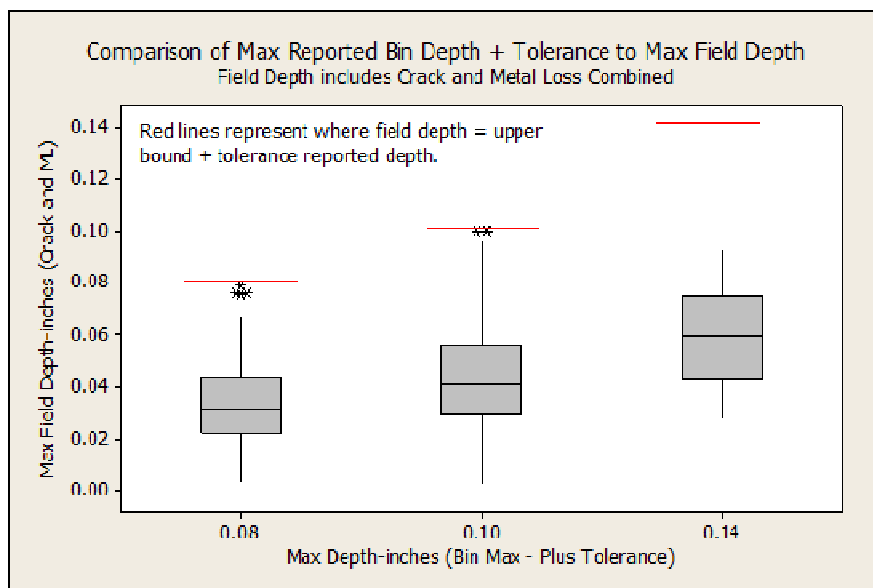


Figure 6: Trending of Coincident Cracking and Corrosion after Tolerance is Included

5 Conclusion and Discussion

Based on the information provided and a cursory review, Enbridge's management of ILI data meets or exceeds current industry practices.

ILI Analysis and Reporting

In reference to ASNT ILI PQ 2005, identification of the analysis team (by number), level of certification, and date of certification are included in the report.

ILI report formats specified by Enbridge, such as ISAS csv files, are created to ensure smooth data integration for all Integrity Management stakeholders.

While the written ILI report discusses inspection logics and data quality as a whole, the electronic Pipeline Listing used by Enbridge delineates, feature by feature, data quality issues that could impact analysis results such as degraded data (i.e. echo loss) and tool velocity. This allows for a more granular view of data quality. The only suggestion concerning the Pipeline Listing used for UTCD inspections would be to further clarify the column REM. WT (mil) so that it is clearly known it is not a measurement of remaining wall as compared to the column WT (mil) which is a measurement made by the tool.

Anomaly Response Plan

Threat integration, trending of ILI reported feature characteristic to field measured characteristics, FfP assessments, and continual improvement are core components of Enbridge's management of ILI data and influence anomaly response plans.

Based on the information provided and using field excavations as a basis, Enbridge's current anomaly response plan for crack-like and crack field features on Line 6B include using the reported length of the crack-like or crack field feature and using the upper bound of the reported depth range plus an added tolerance in FfP calculations. The integrated threat of cracking and corrosion is qualitatively addressed using trending results and adding tolerances as seen in Table 4.

Feedback from excavations will be provided to the ILI service provider and measurement results will be input back into the trending analysis to further understand tool performance and make necessary changes in order to increase consistency between reported anomaly characteristics and those characteristics measured in the field.

Discussions

Enbridge's experience has been that the reported depth range for crack-like and crack field features tends to be inclusive of the measured combined crack depth and corrosion depth found in the field. Clear communication needs to be continued with the service provider to understand if changes to the tool or analysis protocol may change this trend, and likewise trending should be re-visited if a different service provider(s) is used.

For further qualitative consideration, the expectation (based on experience) that the upper bound of the reported depth range for a crack-like or crack field feature is greater than the combined crack depth and corrosion depth found in the field should be validated. One example of validation would be to compare the reported ILI metal loss depth to the upper bound + tolerance crack depth for coincident features identified during the threat integration process. If the reported metal loss is greater than the upper bound + tolerance reported depth of the crack-like or crack field feature, the expectation is not validated.

Potential variability in the UTCD ILI data requires that the depth crack-like and crack field features be reported in ranges. There are currently no best practices that recommend a quantitative approach to account for this variability when implementing critical crack assessments for coincident cracking and metal loss. Qualitative approaches include using the upper bound of the reported depth range in addition to a calibrated tolerance to represent the combined crack and corrosion depth. This approach is based on trending of ILI data and field data.

For the purpose of discussion, several possible quantitative approaches on how to integrate crack-like and crack field features coincident with corrosion for a critical crack assessment are presented in Appendix B. Dependence on the conservatism of the approach and on the UTCD ILI's ability to differentiate crack depth from combined crack and corrosion depth will guide applicability.

Implementation of a quantitative approach for engineering assessments of coincident cracking and corrosion as reported in ILI data integration processes is not trivial. There is not one approach that is appropriate for all scenarios as experiences differ between pipeline operators and possibly between inline inspections for the same operator. Industry support, technical studies and innovative engineering may result in a single common approach that requires standardized feature characterization, drive data analysis improvements or motivate the introduction of new crack detection ILI technology.

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7 Appendix A

Lisa Barkdull

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SUMMARY OF QUALIFICATIONS

Nineteen years experience in the pipeline service industry, primarily focusing on analysis and engineering assessment of in-line inspection (ILI) data. With responsibilities in analysis, engineering, QAQC, and management, have proven ability to motivate employees, direct the focus of a product line, and attain successful entry of product into the market. Expertise in managing personnel working internationally and organizing project flow to meet financial and technical goals. Accustomed to meeting with clients, speaking in industry and government public forums, and actively participating on industry committees.

PROFESSIONAL EXPERIENCE

QUEST INTEGRITY GROUP

Dec 2010 – Present

Senior Consultant – Pipeline Specialist

Responsible for the development and marketing of Quest Integrity's engineering assessment services for the pipeline sector. Support Quest Integrity's Pipeline Services and related technology development in ultrasonic data collection, interpretation, and quality assurance/control.

NDT SYSTEMS AND SERVICES (AMERICA) INC.

2006 – Dec 2010

Tuboscope Pipeline Services (TPS) was acquired by NDT in September 2008.

Manager Data Analysis and Technology (NDT) 2008 – Dec 2010

Manage data analysis departments for all in-line inspection technologies: ultrasonic, magnetic flux leakage, geometry, and inertial navigation systems. Responsible for ensuring financial and technical goals are met. Consult with the Board of Directors on technology issues and technical focus for the company.

- Establishment and management of data analysis organization structure
- Establishment and management of technical and commercial goals
- Development and management of engineering assessment and pipeline integrity expertise
- Work with international software engineering personnel to meet technical goals
- Manage international data analysis integration efforts
- Implementation of internal process and procedures which address current and future industry practices, regulations, and standards

Director Ultrasonic Technology (TPS) 2006 – 2008

Manage an international ultrasonic data analysis department. Responsible for ensuring financial and technical goals are met. Consult with senior management on ultrasonic technology focus. Provide ultrasonic technical expertise to operations, sales, and senior management. Represent the company with clients and in industry and government forums.

- Manage the day to day activities of the ultrasonic data analysis department
- Track and demonstrate improvement in Key Performance Indicators
- Focal point for ultrasonic tool set up, analysis, software, and other technical issues
- Provide technical presentation for the sales department and attend critical sales visits



CC TECHNOLOGIES (CCT A DNV COMPANY)

2006 – 2006

Senior Professional 2006 - 2006

Provide ILI expertise for CCT personnel and pipeline operators to support the effective integrity management of pipelines.

- Validation of ILI surveys and performance specifications
- Comparison of ILI surveys
- Support the assessment of data analysis results and integrity management programs

TUBOSCOPE PIPELINE SERVICES

1992 – 2006

Manager Ultrasonic Data Analysis 2004 – 2006

Manage day to day activities of the ultrasonic data analysis department. Responsible for ensuring financial and technical goals are met. Provide ultrasonic technical expertise to operations, sales, and senior management. Represent the company with clients and in industry and government forums.

Manager Data Analysis Support 2001 – 2004

Support global data analysis groups. Implement and manage year long intensive training program for new data analysts recruited from international markets. Educate operations, sales, and data analysis on current industry standards and regulations. Develop procedures and processes to meet regulation reporting requirements. Involvement with the testing and implementation of new software applications for the data analysis and integrity management departments.

Supervisor Data Analysis 1999 – 2001

Responsible for the day to day activities of the magnetic flux leakage data analysis department. Responsible for production quantity and quality. Implement training for new technologies. Deal closely with clients concerning software, data analysis techniques, and ILI technology.

Engineering Data Analyst 1994 – 1999

Work with engineering and outside research facilities to develop and implement improved algorithms for automated analysis and anomaly characterization. Test and review software applications prior to release. Work with operations to train international data analysis departments in the processing and analysis of magnetic flux leakage data. Communicate with clients regarding survey results and analysis techniques.

Data Analyst Trainee 1992 – 1994

EDUCATION

Master of Science Statistics (2002) University of Houston, Clear Lake

Bachelor of Science Mathematics (1992) University of Houston, Clear Lake

Associate of Science Mathematics (1990) Alvin Community College

8 Appendix B

Quest Integrity Group offers the following ideas for discussion on quantitatively assessing cracking and corrosion. A finite element analysis (FEA) could quantify the conservatism of each approach and define necessary tool and analysis accuracies such that the assessment is applicable and useful.

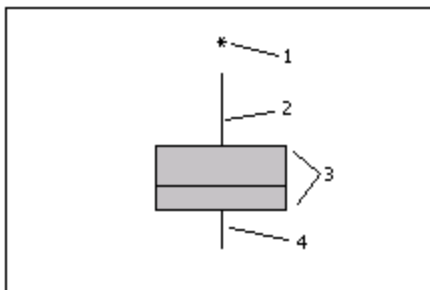
- Jointly consider the reported crack-like or crack field depth and the associated reported metal loss depth into an total crack depth to be used in the assessment. This is the most conservative approach and is most appropriate for cracking at the base of groove-like metal loss.
- Consider assuming uniform thinning. For example, if the wall thickness is 250 mil, the crack depth is 80 mil and the metal loss is 40 mil, the crack calculations would be performed using 80 mil as the depth and assuming the pipe thickness is 210. This method is appropriate when the wall thinning is relatively uniform and there are no notches or significant stress raisers.
- Consideration of applying the remaining strength factor (RSF) defined in API 579 or the equivalent in B31G. Given a calculated critical burst pressure from the appropriate crack equation, this value would be multiplied by RSF to reduce the burst pressure. If a critical crack size is being calculated for reference, the pressure would be divided by RSF to elevate the effective hoop stress used in the calculation.

9 Appendix C

Boxplot

A graphical summary of the distribution of a sample that shows its shape, central tendency, and variability.

The default boxplot display consists of the following:



1 **Outlier (*)** – Observation that is beyond the upper or lower whisker

2 **Upper whisker** – Extends to the maximum data point within 1.5 box heights from the top of the box

3 **Interquartile range box** – Middle 50% of the data

- Top line – Q3 (third quartile). 75% of the data are less than or equal to this value.
- Middle line – Q2 (median). 50% of the data are less than or equal to this value.
- Bottom line – Q1 (first quartile). 25% of the data are less than or equal to this value.

4 **Lower whisker** – Extends to the minimum data point within 1.5 box heights from the bottom of the box

Boxplots can help you understand your distribution. For example, the boxplot above represents hold times for customer support calls. The outlier at the upper end and longer upper whisker and upper part of the box indicate positive skewness, which makes sense because at the lower end of the distribution, no hold times can be less than zero.

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