DOT	US Department of Transportation
PHMSA	Pipeline and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety
	Central Region

Principal Investigator	Karen Butler/Jim Bunn
Region Director	David Barrett
Date of Report	6/11/2012
Subject	Failure Investigation Report – Enbridge Line 14 Rupture Atwood (Owen), WI

Operator, Location, & Consequences

Date of Failure	January 1, 2007
Commodity Released	Crude Oil
City/County & State	Atwood/Clark County, Wisconsin
OpID & Operator Name	11169 Enbridge Energy, Limited Partnership
Unit # & Unit Name	1343 Fort Atkinson
SMART Activity #	118537
Milepost / Location	MP 149.44
Type of Failure	ERW Longitudinal Weld Seam Failure
Fatalities	0
Injuries	0
Description of area impacted	Rural Area, Non-HCA
Total Costs	$702,500

Executive Summary

On 01/01/07 at approximately 8:49 am CST, a pipeline controller located in the Enbridge Control Center (ECC) detected a sudden drop in discharge pressure at Owen pump station on Line 14. The pipeline controller immediately initiated shutdown procedures for Line 14, closed station valves on either side of Owen and at Owen pump station, and dispatched emergency response personnel. A landowner contacted the ECC to report an odor within 30 minutes of Line 14 shutdown. At approximately 12:15 pm CST, emergency response personnel discovered oil flowing in a ditch and a rupture in Line 14 was verified at MP 149.4373 near Atwood, WI (approximately one mile downstream of Owen pump station). Crude oil had continued to travel away from the rupture site through a natural ditch area close to a mile in length. An estimated 1,500 barrels of crude oil was released, 1,450 barrels were recovered, and 4,625 cubic yards of contaminated soil were removed and taken to a disposal facility.

The failed line pipe was 24-inch OD, 0 .328 wall thickness, API 5L, Grade X-70, High-Frequency ERW, coated with fusion bonded epoxy and manufactured by Stupp Pipe Corporation in 1998. The depth of cover at the failure location was 60 inches. The pipe had been hydrotested following construction. The Maximum Operating Pressure (MOP) was reported to be 1377 psig and the pressure at the point of failure was calculated to be 1331 psig. The failed section of pipe was cut out and approximately 50 feet of new pipe was installed. The pipeline was returned to service on 01/03/07 with a 20 percent reduction in operating pressure.

There were no injuries, fatalities or evacuations associated with the failure. A fire was not present and the failure did not occur in an HCA. The supply impact from the rupture was minimized due to a parallel pipeline that remained in operation. The operator reported that total costs associated with the release were $702,500.

The rupture was determined by metallurgical analysis to be the result of a lack of fusion defect located in the ERW longitudinal seam near the ID of the pipe and adjacent to the upstream girth weld. The fracture propagated across the adjacent upstream girth weld. This original defect grew to failure while in service (under cyclic loads) by a fatigue mechanism. The metallurgical report indicated that the "rupture initiated at the defect when the flaw size exceeded the critical flaw size for the material properties, dimensions, and operating pressure."

System Details

Enbridge Energy, Limited Partnership (Enbridge) at the time of this report operates approximately 5,470 miles of pipelines, associated pump stations and breakout tanks in the United States. Enbridge has over 3,600 miles of right-of-way grouped under several units known as Lakehead, Ozark, CCPS (Spearhead), Toledo and Patoka (breakout tank facility) with more in development. Several areas have pipelines in common corridors including the failure location. The majority of the system transports crude oil. Enbridge also operates several HVL pipelines in the US. At the time of the failure, the crude oil systems operated were 3,338 miles in length with 1,030 miles located in areas that could affect an HCA.

Line 14 is part of the Lakehead system and transports crude oil from the Enbridge Superior, Wisconsin to Mokena, Illinois. This portion of the Lakehead system was originally 461 miles in length and comprised of 24-inch diameter, X70 pipe with wall thickness ranging from 0.328 inch to 0.500 inch. A review of PHMSA data indicates that Lakehead had experienced 14 reportable failures prior to this rupture associated with this unit, several due to equipment or material failure.

Events Leading up to the Failure

Radiographic technicians inspecting each girth weld during pipeline construction in 1998 identified defects in a number of ERW longitudinal seams adjacent to the girth welds. The defects were identified as lack of fusion. Twenty lengths of pipe that contained such defects were removed from the pipeline for further analysis. Eleven of the twenty lengths of pipe removed were determined to contain significant weld defects on the inside diameter of the pipe and were sent to a metallurgical consultant for further evaluation. The consultant determined that seven of the lengths of pipe contained defects that would be rejected per API 5L specifications applicable to the pipe at the time of manufacture. The evaluation performed by the third party metallurgical specialist of these 7 defects determined that three of the defects would survive at least 20 years, 1 was large enough to fail during a post construction hydrostatic test to 1818 psi or 95% of SMYS of the 0.328 inch wall thickness, and 3 would be expected to grow to failure in some time shorter than 20 years.

Enbridge initiated an investigation with third party consultants that encompassed: a metallurgical analysis to determine the characteristics of the weld defects; a review of pipe mill production records to determine if the defects had been identified during pipe mill inspection processes; an assessment of the pipe mill's quality assurance/quality control process. This investigation determined that all of the defects were lack of fusion type, were located on the inside diameter of the pipe, and had been identified during the pipe mill inspection processes. The investigation also discovered that the total defect length had not been determined, completely marked or removed properly. This resulted in some joints having only a portion of the weld defect removed from the line pipe at the mill. Line pipe lengths that contained the remaining portions of the defect were sent to the pipeline right-of-way. These lengths of pipe were subsequently welded into the pipeline.

The Stupp Pipe Corporation manufactured the pipe used to construction Line 14 at the facility in Baton Rouge, Louisiana. The high frequency electric resistance welded (HF ERW) pipe was manufactured in accordance with API 5L and was grade X-70. The pipe diameter was 24-inch and wall thicknesses ranged from 0.328 to 0.500 inch. The pipe was coated with fusion bonded epoxy at the pipe mill. The pipe mill facilities had been upgraded in 1997. One of the pipe mill upgrades consisted of the addition of a zip welder which was used to join coils together. The zip welder allowed the pipe mill to continue to run without stopping between coils.

Enbridge's construction specification required that 100% of the girth welds in the pipeline be examined using radiographic techniques. In an effort to find all similar defects, Enbridge had all of the radiographs re-evaluated to determine if any additional lack of fusion defects remained in the pipeline near a girth weld. Enbridge determined that there was a high statistical probability that all of the lack of fusion defects had been removed from the pipeline. The pipeline was hydrostatically tested on August 31, 1998 and the test pressure at the failure location was 1818 psig. Enbridge reported that the hydrotest duration was eight hours in length.

The Lakehead Line 14 pipeline was placed in service in January of 1999. Just prior to the time of the rupture on Jan. 1,2007, pumps had been started at Sheldon and Owen pump stations located upstream of the rupture location and at Vesper pump station located downstream of rupture location. This resulted in a pressure increase at Owen station as expected. Enbridge reviewed pressure data and reported that evidence did not exist to support any overpressure event occurrence at or near Owen pump station at the time of the rupture. The Enbridge internal accident investigation reported that the pressure at the Owen station reached 1347 psig with an MOP at this location of 1374 psig. Enbridge calculated that a pressure at the failure location would have been 1331 psig at the time of failure and that the failure location would have an MOP of 1377 psig.

Emergency Response

The ECC detected a sharp pressure drop on the Owen station discharge at 08:49 am CST and immediately initiated a shutdown of the pipeline. By 08:50 am CST, all pumps upstream of the Owen station had been shut down. All remote control valves between Sheldon station and Owen station were closed and all remote control valves between Owen station and Vesper station were closed shortly after the shutdown. Response personnel were dispatched downstream of Owen station to search for the release. Within 30 minutes of the Line 14 shut down, a landowner who was in the vicinity of the failure site called the Control Center to report a crude oil odor. The release site was located and confirmed approximately one mile downstream of Owen station by 12:15 pm CST. Enbridge reports that the length of the line that was isolated between valve locations was approximately 15 miles. The area around the release was reported to be made safe with 2.5 hours. Enbridge did not report this accident to the NRC until 15:22 EST (13:22 MST) on January 1, 2007. The initial NRC report listed an incorrect state (Indiana rather than Wisconsin) in the Incident Location section.

Summary of Return-to-Service

The rupture site was excavated and the segment of pipe that failed was exposed. The crude oil was drained from the pipe segment that contained the rupture and a fifty foot section of pipe was removed and replaced with pre-tested pipe. The fifty foot segment of pipe that was removed from the pipeline was cut into two pieces and wrapped for protection during transport. This piece of pipe that contained the rupture section was sent to a metallurgical facility for further evaluation. The other portion of the pipeline removed from service was wrapped for storage and sent to the Enbridge yard at Griffith, Indiana. The portion of Line 14 impacted by the failure resumed operation on January 3, 2007 at a reduced operating pressure. The MOP at each pump station along the pipeline was limited to 80% of the maximum discharge pressure experienced during the 15 day period immediately prior to the time of the rupture. The MOP at the rupture site was limited to a maximum of 80% of the pressure at the time of the rupture or 1064 psig.

PHMSA worked extensively with the operator and Enbridge agreed to complete a metallurgical failure analysis; complete an in-line inspection of the entire Line 14 pipeline with an ultrasonic crack detection tool; complete a crack excavation and repair program; complete a fatigue testing program; and establish an in-line re-inspection interval based on the fatigue analysis.

The failure location metallurgical analysis report was finalized on March 13, 2007. The in-line inspection was completed in 2007, additional metallurgical analysis of a coupon sample at MP 32.41 was completed in 2007, and the excavation and repair program was completed in 2008. The fatigue analysis was completed in July of 2008 and a re-inspection interval of five years was established based on the size of anomaly that could remain in the pipeline and an analysis of the pressure cycles that could occur based on operating history and pipe material properties. The first in-line re-inspection was scheduled for 2012. PHMSA approved the return of Line 14 to its original operating pressure in September of 2008.

Investigation Details

A PHMSA representative arrived at the site in the evening (21:00) on January 2, 2007 and witnessed the removal of the failed section of pipe, the subsequent repair and the nondestructive testing of the girth welds, the preparation for shipment of the failed section of pipe and the loading of the pipe to a truck transport. Photographs of the failed section of pipe were taken while on site.

This investigation involved a detailed review of metallurgical analysis on multiple sections of pipeline, a review of the calculated or predicted failure pressures using CorLas software, ILI data with multiple tools, a fatigue assessment and analysis that involved historical pressure cycling review and dig verification accompanied by pipeline repair. The metallurgical analysis, fatigue analysis and ILI information will be discussed in detail.

METALLURGICAL ANALYSIS

The length of pipe that contained the rupture was sent to CC Technologies in Dublin, Ohio. CC Technologies conducted a metallurgical failure analysis in accordance with the PHMSA Metallurgical Laboratory Failure Examination Protocol. The failure analysis included an optical examination, a magnetic particle inspection, an ultrasonic inspection, a fractographic examination, a metallographic examination, an examination of the fracture surface with a scanning electron microscope, a determination of the chemical composition of the pipe steel and a determination of mechanical properties of the pipe steel. The following conclusions were reached at the completion of the failure analysis:

1) The fracture was at the 2 o'clock position.
2) The rupture initiated at an ID surface breaking defect located at the ERW seam weld adjacent to the upstream girth weld.
    a. The lack of fusion defect penetrated the surface on the internal diameter of the pipe.
3) There is evidence that the defect grew in service by a fatigue mechanism.
    a. The fracture propagated across the adjacent upstream girth weld.
    b. The defect was adjacent to the upstream girth weld and the initial depth of the defect was determined to be 30% of the pipe wall thickness.
    c. The defect grew in service by a cyclical fatigue mechanism to a depth of 66.7% of the wall thickness at which point the fracture initiated.
4) The ERW weld seam exhibited low toughness near the fracture origin.
    a. There is evidence of cleavage in the fast fracture zone between the lack of fusion (LOF) flaw and the OD pipe surface at the bond line, indicating low toughness of ERW seam.
5) Away from the failure origin, the seam weld exhibited good mechanical properties and met API specifications.
6) The mechanical properties of the base metal met API 5L specifications that were in affect when the pipe was produced.
7) The chemical composition of the base metal met API 5L specifications that were in affect when the pipe was produced.

As the result of ILI run which will be discussed in detail further in this report, a defect was found at MP 32.41 and a second metallurgical analysis was performed on a coupon sample with similar pipe characteristics (X70, HF ERW, 0.328 w.t., etc.) located within this section of pipe. This metallurgical analysis involved an optical examination, angle beam ultrasonic testing, fractographic examination, metallographic examination, burst pressure analysis, examination with a scanning electron microscope (SEM) and chemical analysis. Analysis of the coupon resulted in the following conclusions:

1) The location and morphology of the defect was consistent with a hook crack.
2) The ends of the weld contained a defect so the endpoints were not located. The defect was at least 21.5 inches in length. The defect is longer than the angle beam UT data.
3) The maximum depth of the defect measured from the fracture surface was 0.102 inches (31.1% of wall thickness) which is less than the depth category reported by the ILI tool but within the limits of that reported by the UT.
4) The UT identified two defects from the external surface but only one defect was identified visually. There were some difficulties in detecting the defects from the internal surface.
5) There was no evidence of in-service growth on the defect surface.
6) The composition of the sample removed from the base metal met API 5L X70 pipe steel composition specifications at the time of manufacture.

FATIGUE ANALYSIS

The next step in the failure investigation process was to conduct a fatigue assessment. The methodology used to calculate fatigue crack growth is described in British Standard 7910, Guide to Methods for Assessing the Acceptability of Flaws in Metallic Structures, and American Petroleum Institute Recommended Practice 579, Fitness For Service. Under this approach a flaw may be represented as a sharp-tipped crack which propagates in accordance with a formula that relates the crack growth rate to the range of the stress intensity factor for the material that contains the flaw. This formula is known as the Paris law. The Paris law incorporates two constants, C and m, which depend on the material and the applied conditions, including the environment and cyclic frequency. This equation requires the understanding that the crack growth rate changes as the flaw grows. The two constants may be established (determined experimentally) or may be taken from published data. The overall fatigue life is calculated by integrating the Paris law equation from the initial flaw size to the final critical flaw size. Specialized computer software is used to perform these calculations.

This method incorporates the following assumptions.

1) Surface flaws are assumed to have a semi-elliptical shape.
2) Fatigue crack growth is described by the Paris law equation, $da/dN = C(\Delta K)^m$.
3) The stress intensity factor range, ΔK, is a function of the crack size and the cyclic stress range, and may be calculated in accordance with BS 7910 Annex M.
4) A pressure spectrum can be converted into identifiable stress ranges using a rainflow cycle counting technique (in accordance with ASTM-1049 and E-1049).
5) A two-term Folias correction factor is incorporated to account for the bulging effect that occurs near axial flaws in pipe.
6) The effects of pipe ovality are accounted for in accordance with BS 7910 Annex D.

Enbridge contracted with CC Technologies to complete the fatigue analysis. In order to determine the fatigue growth rate that occurred on Line 14, CC Technologies measured the size of the initial flaw and measured the size of the flaw just prior to failure. Next they determined the hoop stress spectrum that the pipeline was subjected to by performing a rainflow analysis of the pipeline pressure history since the pipeline began operation in January of 1999. A back-calculated value for C and m constants using the Paris law was obtained to match the results of crack growth to failure in the eight years previous to failure. Established values for C and m constants were also obtained based on full scale fatigue tests that were conducted on other segments of pipe that were removed from Line 14. The Paris law constants were then compared. The m value in both cases was calculated to be 3, which is the same value recommended in BS 7910. The C value for the actual failure location was determined to be $9.8x10^{-10}$ with an ovality 0% and $7.0x10^{-10}$ with an ovality of 0.5%. The C value for the full scale fatigue test was determined to be $5.6x10^{-10}$ with an ovality of 0% and $3.9x10^{-10}$ with an ovality of 0.4%. The recommended value of C contained in BS 7910 is $8.6x10^{-10}$. Until this time Enbridge had been using a C value of $2.5x10^{-10}$ and an m value of 3 to estimate fatigue growth rates. Thus, previous estimates of fatigue growth rates were not conservative based on established literature.

As a result of the investigation, CC Technologies recommended that Enbridge modify their fatigue analysis procedures as follows.

1) The Paris law constants should be in accordance with BS 7910 unless line-specific information would justify the use of other values;
2) The procedure to consider ovality or weld joint misalignment should be in accordance with BS 7910 or constants for the Paris law should be used that inherently include these effects.
3) The initial flaw size used in a fatigue analysis should be based on the likely size of remaining anomalies based on an in-line inspection.

IN-LINE INSPECTION

Enbridge contracted with GE Oil & Gas to run both a magnetic flux leakage (MFL) metal loss in-line inspection tool and an ultrasonic crack detection (USCD) tool through the entire length of Line 14. Both tools were run in the month of April 2007. The final MFL report was received in September of 2007 and the final USCD report was received in July of 2007.

The MFL (GE Magnescan) tool did not identify any features that met the Enbridge repair criteria. Four validation digs were determined to have field assessments with two dig locations being completed in September and December of 2007. The validation digs did confirm the presence of metal loss but the anomalies did not meet repair criteria.

The USCD tool identified 128 crack like features, 932 notch like features, 3 metal loss features and 84 dents. Point pressure restrictions were imposed on the pipeline at each location where the anomaly had a calculated failure pressure below the hydrostatic test pressure in order to achieve an immediate safety factor of 1.25. Anomalies were excavated (97 field excavations required), evaluated and repaired as required to maintain a calculated failure pressure above 1.25 x MOP. As of February 1, 2008 there were no known anomalies left in the pipeline with a calculated failure pressure below 1.25 x MOP.

Enbridge did compare in-line inspection tool data with defect measurements made in the field with hand held ultrasonic inspection equipment. Based on the data comparison the tool performed in accordance with the tool specifications and showed a conservative bias. Enbridge did recognize that there was a possibility of a defect being undersized or undetected. PHMSA believes that this possibility must be taken into account when making decisions concerning the fitness for purpose of the pipeline.

Findings and Contributing Factors

Enbridge and their technical partners used the metallurgical data, a strength analysis to review calculated failure pressures (using CorLAS software), the fatigue growth data and the in-line inspection tool data to evaluate the fitness for purpose of the pipeline and to establish a re-inspection interval for the in-line inspection tool.

Enbridge did not report the accident to the NRC promptly.

The NRC report did not identify the incident location in the correct state.

The Operator Accident Report (30 day report) did not show the time of the accident as the time that the rupture occurred according to SCADA data and other sources internal to Enbridge (8:49 CST). The Operator Accident Report did show the time of the accident based on their confirmation of the release and the time at which the release reached reportable thresholds (11:15 MST).

PHMSA provided oversight of the investigation and evaluated the future operation of Line 14 based on a thorough review of the data provided during the investigation. The following conclusions and findings were reached as a result of a comprehensive investigation that was undertaken by Enbridge, the technical support partners and PHMSA review:

1) During the Line 14 pipe manufacturing process, lack of fusion type defects were introduced into the ERW weld seam in multiple joints of pipe. These defects were identified as cause for rejection during the pipe inspection process. The extent of the defects was not determined accurately so the defects were not completely removed from multiple pipe joints and line pipe containing defects made it to the pipeline right-of-way.

2) A change in the pipe manufacturing process was implemented just prior to the production of the pipe for Line 14.

3) Pipe joints that contained this lack of fusion type defect were sent to the pipeline right-of- way and installed in Line 14.

4) Some of these defects were identified during construction of the pipeline by nondestructive inspection technicians who were examining each pipeline girth weld. When the technicians were examining radiographs of the girth welds, lack of fusion in some ERW longitudinal seams adjacent to girth welds was identified. The extent of the defect could not be determined.

5) The nondestructive inspection technicians made Enbridge personnel aware of their discovery and an investigation by Enbridge and an independent metallurgical consultant in cooperation with others ensued.

6) At the time of construction, twenty pipe segments were selected for removal from the pipeline as the girth weld radiographs showed that the ERW weld seam adjacent to the girth weld contained a lack of fusion defect. Eleven of these pipe segments were found to have significant ERW seam defects. After further evaluation it was determined that seven of these pipe segments contained lack of fusion type defects that would be cause for rejection in accordance with API 5L.

7) 100% of the girth welds in Line 14 had been subjected to radiographic inspection. The radiographs of all of these girth welds were re-evaluated in an effort to determine if any additional lack of fusion defects were present in the pipeline. No evidence of additional defect indications was discovered.

8) At the time of construction, the evaluation performed by the third party metallurgical specialist of the 7 defects found in the longitudinal seam for several joints of ERW pipe determined that 3 of the defects would survive at least 20 years, 1 was large enough to fail during a post construction hydrostatic test to 1818 psi or 95% of SMYS of the 0.328 inch wall thickness, and 3 would be expected to grow to failure in some time shorter than 20 years.

9) The joint investigation performed during the time of construction concluded that the number of pipe joints that contained the lack of fusion type of defect was very limited and there was a high statistical probability that all such defects had been removed from the pipeline prior to commissioning.

10) The origin of the January 1, 2007 failure was a lack of fusion type defect that remained in the pipeline. During the metallurgical investigation the initial length of this defect was determined to be 3 ½ inches and the initial depth of this defect was 30% of the pipe wall thickness or 0.098 inches.

11) The metallurgical investigation also determined that this defect grew to a critical size by a fatigue growth mechanism related to normal operating pressure cycles. The defect was 3 -1/2 inches long and 60% of the pipe wall or 0.197 inches in depth when it reached critical size.

12) Chemical and mechanical properties of the pipe joint met specification requirements except in the area of the fracture origin where the fracture toughness values were determined to be low.

13) A fatigue study was used to establish the proper coefficients to be used in the Paris law equation. The default coefficients that Enbridge used prior to this failure were a C value of 2.5×10^{-10} and an m value of 3. The fatigue study found that the m value that Enbridge had been using was correct but that the C value used would result in an overestimation of fatigue life by a factor in excess of 3. The study recommended that a C value of 8.6×10^{-10} and an m value of 3 be used in future fatigue growth analyses.

14) The ultrasonic crack detection tool identified 1147 anomalies that had a calculated failure pressure of less than 1.25 x MOP at the location of the defect. All of these anomalies were excavated, evaluated and repaired as required. Seam defects were found at various locations within pipe joints, not just on the ends of pipe joints as originally indicated during the investigation that was performed while construction activities were ongoing.

15) The operator, Enbridge, reported to PHMSA that all anomalies identified in the in-line inspection program that had a calculated failure pressure of less than 1.25 x MOP have been removed from the pipeline.

16) A fatigue life was calculated for the known anomalies that were left in the pipeline. The fatigue life of those anomalies ranged from 10.8 years to 93.3 years.

17) Enbridge recognizes that there is a finite possibility of a defect being undersized by an in-line inspection tool or not being detected by an in-line inspection tool. Enbridge recognizes that a defect could be smaller than the ability of the ILI tools to detect and Enbridge recognized that tool results must be validated to confirm tool accuracy. In the case of Line 14, tool performance was validated.

18) Enbridge recognizes that there are additional sources of uncertainty that must be considered in fitness for purpose studies. As a result, the lowest calculated fatigue life in a system is divided by 2 to determine the re-inspection interval.

19) The lowest calculated fatigue life on Line 14 was 10.8 years so Enbridge determined the re-inspection interval for Line 14 to be 5 years. The next in-line inspection for Line 14 is scheduled for 2012.

This failure investigation identifies: the need for operators to be aware of the pipe manufacturer's processes and any recent changes that may be implemented just before a pipe order is filled; the importance of a thorough, repeatable, and understood quality assurance and quality control (QA/QC) process at the pipe mill; the value of 100% radiographs for girth welds and a thorough construction inspection process; the requirement that operators use properly established constants in the calculations associated with the use of the Paris law for fatigue life estimates and include ovality considerations; and the need for operators to continually during the life of a pipeline asset follow up on those risk elements identified during construction activities.

Appendices

A Maps and Photographs

B NRC Report

C Operator Accident Report

D Metallurgical Analysis

Appendix A

Drawings

This document is on file at PHMSA

Appendix A Maps and Photographs

NATIONAL RESPONSE CENTER 1-800-424-8802
*** For Public Use ***
Information released to a third party shall comply with any applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 822512

INCIDENT DESCRIPTION

*Report taken at 15:22 on 01-JAN-07
Incident Type: PIPELINE
Incident Cause: EQUIPMENT FAILURE
Affected Area:
The incident was discovered on 01-JAN-07 at 12:00 local time.
Affected Medium: LAND ONTO THE GROUND

SUSPECTED RESPONSIBLE PARTY

Organization: ENBRIDGE ENERGY
GRIFFITH, IN 46319

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

MAIN LINE County: CLARK
State: IN
Section: 27 NW QUARTER Township: 28 NORTH Range: 1 WEST NEAR OWEN, WI

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 25 BARREL(S)

DESCRIPTION OF INCIDENT

CALLER STATED THERE WAS A RELEASE OF MATERIALS FROM A 24" STEEL PIPELINE DUE TO EQUIPMENT FAILURE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

DAMAGES

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES:	NO	Hospitalized:	Empl/Crew:	Passenger:
FATALITIES:	NO	Empl/Crew:	Passenger:	Occupant:
EVACUATIONS:	NO	Who Evacuated:	Radius/Area:	
Damages:	NO			

Closure Type		Description of Closure	Length of Closure	Direction of Closure	
Air:	N				
Road:	N				Major Artery: N
Waterway:	N				
Track:	N				

Passengers Transferred: NO

Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material: NO

REMEDIAL ACTIONS

CALLER STATED A CREW IS ON SITE WITH A VACUUM TRUCK. CALLER STATED BOOMS ARE IN PLACE AS WELL AND LINE HAS BEEN SHUT DOWN.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: OVERCAST, 35ºF

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: NONE
State/Local On Scene:
State Agency Number:

NOTIFICATIONS BY NRC

ATLANTIC STRIKE TEAM (PRIMARY)
01-JAN-07 15:32
CG INVESTIGATIVE SVC CHICAGO (CGIS ROA CHICAGO)
01-JAN-07 15:32
DOT CRISIS MANAGEMENT CENTER (PRIMARY)
01-JAN-07 15:32
U.S. EPA V (PRIMARY)
01-JAN-07 15:36
U.S. EPA V (KEVIN TURNER)
01-JAN-07 15:32
NATIONAL INFRASTRUCTURE COORD CTR (PRIMARY)
01-JAN-07 15:32
NOAA RPTS FOR IN (PRIMARY)
01-JAN-07 15:32
ORSANCO ATTN: J. SCHULTE (PRIMARY)
01-JAN-07 15:32
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
01-JAN-07 15:32
IN DEPT ENV MNGMT ATTN: BEAUCHAMP (PRIMARY)
01-JAN-07 15:32
KY DEP/ERT ATTN: MR. DAVID LEO (PRIMARY)
01-JAN-07 15:32
SURFACE TRANS SECURITY INSPECT PROG (COMMAND CENTER)
01-JAN-07 15:32

ADDITIONAL INFORMATION

CALLER STATED STATE AGENCIES WILL BE CALLED NEXT (WI EPA).

*** END INCIDENT REPORT # 822512 ***

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $25,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $500,000 as provided in 49 USC 60122

Form Approved
OMB No. 2137-0047

U.S. Department of Transportation
Research and Special Programs Administration

ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS

Report Date jan 30,2007

No. 20070029 -- 13746
(DOT Use Only)

INSTRUCTIONS

Print

Important: Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the Office Of Pipeline Safety Web Page at http://ops.dot.gov.

PART A – GENERAL REPORT INFORMATION

~~Check one or more boxes as appropriate:~~

☐ Original Report ☒ Supplemental Report ☒ Final Report

1. a. Operator's OPS 5-digit Identification Number (if known) / 11169 /
2. b. If Operator does not own the pipeline, enter Owner's OPS 5-digit Identification Number (if known) / /
   c. Name of Operator ENBRIDGE ENERGY, LIMITED PARTNERSHIP
   d. Operator street address 119 N 25TH STREET E
   e. Operator address SUPERIOR DOUGLAS WI 54880
   City, County, State and Zip Code

IMPORTANT: IF THE SPILL IS SMALL, THAT IS, THE AMOUNT IS AT LEAST 5 GALLONS BUT IS LESS THAN 5 BARRELS, COMPLETE THIS PAGE ONLY, UNLESS THE SPILL IS TO WATER AS DESCRIBED IN 49 CFR §195.52(A)(4) OR IS OTHERWISE REPORTABLE UNDER §195.50 AS REVISED IN CY 2001.

2. Time and date of the accident

/ 1115 / hr. / 01 / month / 01 / day / 2007 / year

3. Location of accident
(If offshore, do not complete a through d. See Part C.1)

a. Latitude: 44° 52' 56.10 Longitude: -90° 29' 14.8
(if not available, see instructions for how to provide specific location)

b. ATWOOD CLARK
City, and County or Parish

c. WI 54460
State and Zip Code

d. Mile post/valve station or survey station no.
(whichever gives more accurate location)

149.43

4. Telephone report

/ 822512 / NRC Report Number / 01 / month / 01 / day / 2007 / year

5. Losses *(Estimated)*

Public/Community Losses reimbursed by operator:

Public/private property damage	$ 0
Cost of emergency response phase	$ 0
Cost of environmental remediation	$ 0
Other Costs	$ 0
(describe)	

Operator Losses:

Value of product lost	$ 2500
Value of operator property damage	$ 0
Other Costs	$
(describe)	
Total Costs	$ 700000

6. Commodity Spilled Yes No
(If Yes, complete Parts a through c where applicable)

a. Name of commodity spilled

b. Classification of commodity spilled:
HVLs /other flammable or toxic fluid which is a gas at ambient conditions
CO_2 or other non-flammable, non-toxic fluid which is a gas at ambient conditions
Gasoline, diesel, fuel oil or other petroleum product which is a liquid at ambient conditions
Crude oil

ALBIAN HEAVY SYNTHETIC

REPAIR AND CLEANUP

c. Estimated amount of commodity involved :
Barrels 702500
Gallons (check only if spill is less than one barrel)

Amounts:
Spilled :

Recovered:

CAUSES FOR SMALL SPILLS ONLY (5 gallons to under 5 barrels) :

(For large spills [5 barrels or greater] see Part H)

Corrosion **Natural Forces** **Excavation Damage** **Other Outside Force Damage**
Material and/or Weld Failures **Equipment** **Incorrect Operation** **Other**

1500

PART B – PREPARER AND AUTHORIZED SIGNATURE

1450

(type or print) Preparer's Name and Title

Area Code and Telephone Number

Preparer's E-mail Address

Area Code and Facsimile Number

Authorized Signature (type or print) Name and Title Date Area Code and Telephone Number

THERESA PICTON (715) 394-1468

THERESA.PICTON@ENBRIDGE.COM (832) 325-5477

PART C – ORIGIN OF THE ACCIDENT (Check all that apply)

1. Additional location information
   a. Line segment name or ID ______________________
   b. Accident on Federal land other than Outer Continental Shelf Yes No
   c. Is pipeline interstate? Yes No

Offshore: Yes No *(complete d if offshore)*
d. Area ___________________ Block # ______________
State /______/ or Outer Continental Shelf

2. Location of system involved (*check all that apply*)
   - Operator's Property
   - Pipeline Right of Way
   - High Consequence Area (HCA)?
   - Describe HCA________________________________

3. Part of system involved in accident
   - Above Ground Storage Tank
   - Cavern or other below ground storage facility
   - Pump/meter station; terminal/tank farm piping and equipment, including sumps
   - Other *Specify:* ________________________________
   - Onshore **pipeline**, including valve sites
   - Offshore **pipeline**, including platforms

*If failure occurred on **Pipeline**, complete items a - g:*

4. Failure occurred on

Body of Pipe	Pipe Seam	Scraper Trap
Pump	Sump	Joint
Component	Valve	Metering Facility
Repair Sleeve	Welded Fitting	Bolted Fitting
Girth Weld		
Other *(specify)* ____________________		

Year the component that failed was installed: /______________/

5. Maximum operating pressure *(MOP)*
   a. Estimated pressure at point and time of accident: __________ *PSIG*
   b. MOP at time of accident: __________*PSIG*
   c. Did an overpressurization occur relating to the accident? Yes No

a. Type of leak or rupture
   Leak: Pinhole Connection Failure *(complete sec. H5)*
   Puncture, diameter *(inches)* ____________________
   Rupture: Circumferential – Separation
   Longitudinal – Tear/Crack, length *(inches)* __________
   Propagation Length, total, both sides *(feet)* _________
   N/A
   Other ____________________________________

b. Type of block valve used for isolation of immediate section:
   Upstream: Manual Automatic Remote Control Check Valve
   Downstream: Manual Automatic Remote Control Check Valve

c. Length of segment isolated _______ ft
d. Distance between valves _______ ft
e. Is segment configured for internal inspection tools? Yes No
f. Had there been an in-line inspection device run at the point of failure? Yes No Don't Know
   Not Possible due to physical constraints in the system
g. If *Yes*, type of device run (*check all that apply*)

High Resolution Magnetic Flux tool	Year run: _______
Low Resolution Magnetic Flux tool	Year run: _______
UT tool	Year run: _______
Geometry tool	Year run: _______
Caliper tool	Year run: _______
Crack tool	Year run: _______
Hard Spot tool	Year run: _______
Other tool	Year run: _______

1. Nominal pipe size *(NPS)* /____________/ in.
2. Wall thickness /____________/ in.
3. Specification ______________ SMYS /____________________/
4. Seam type ____________________________________
5. Valve type ____________________________________
6. Manufactured by ________________ in year /______________/

PART E – ENVIRONMENT

1. Area of accident
   - In open ditch
   - Under pavement
   - Above ground
   - Underground
   - Under water
   - Inside/under building
   - Other ____________________
2. Depth of cover: _________________ inches

PART F – CONSEQUENCES

1. Consequences *(check and complete all that apply)*

a.

	Fatalities	Injuries
Number of operator employees:	_______	_______
Contractor employees working for operator:	_______	_______
General public:	_______	_______
Totals:	_______	_______

b. Was pipeline/segment shutdown due to leak? Yes No
   If Yes, how long? ______ days ______ hours _____ minutes

c. Product ignited Yes No
d. Explosion Yes No
e. Evacuation *(general public only)* /______________/ people
   Reason for Evacuation:
   - Precautionary by company
   - Evacuation required or initiated by public official
f. Elapsed time until area was made safe:
   /______/ hr. /______/ min.

2. Environmental Impact

a. Wildlife Impact:

Fish/aquatic	Yes	No
Birds	Yes	No
Terrestrial	Yes	No

b. Soil Contamination Yes No
   If Yes, estimated number of cubic yards: ___________
c. Long term impact assessment performed: Yes No
d. Anticipated remediation Yes No
   If Yes, check all that apply: Surface water Groundwater Soil Vegetation Wildlife

e. Water Contamination: Yes No (*If Yes, provide the following*)
   Amount in water _________ barrels

Ocean/Seawater	No	Yes
Surface	No	Yes
Groundwater	No	Yes
Drinking water	No	Yes (*If Yes, check below.)*

   Private well Public water intake

PART G – LEAD DETECTION INFORMATION

1. Computer based leak detection capability in place? Yes No
2. Was the release initially detected by? (check one): CPM/SCADA-based system with leak detection
   Static shut-in test or other pressure or leak test
   Local operating personnel, procedures or equipment
   Remote operating personnel, including controllers
   Air patrol or ground surveillance
   A third party Other (specify) _________________
3. Estimated leak duration days ____ hours ____

PART H – APPARENT CAUSE

Important: *There are 25 numbered causes in this Part H. Check the box corresponding to the primary cause of the accident. Check one circle in each of the supplemental categories corresponding to the cause you indicate. See the instructions for guidance.*

H1 – CORROSION

1. External Corrosion
2. Internal Corrosion

(Complete items a – e where applicable.)

a. Pipe Coating
- Bare
- Coated

b. Visual Examination
- Localized Pitting
- General Corrosion
- Other ____________________

c. Cause of Corrosion
- Galvanic
- Atmospheric
- Stray Current
- Microbiological
- Cathodic Protection Disrupted
- Stress Corrosion Cracking
- Selective Seam Corrosion
- Other ____________________

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering accident?
No Yes, Year Protection Started: /______________/

e. Was pipe previously damaged in the area of corrosion?
No Yes => Estimated time prior to accident: /_______/ *years* /_______/ *months* *Unknown*

H2 – NATURAL FORCES

3. Earth Movement => Earthquake Subsidence Landslide Other ______________________________
4. Lightning
5. Heavy Rains/Floods => Washouts Flotation Mudslide Scouring Other __________________
6. Temperature => Thermal stress Frost heave Frozen components Other ________________________
7. High Winds

H3 – EXCAVATION DAMAGE

8. Operator Excavation Damage (including their contractors/Not Third Party)
9. Third Party *(complete a-f)*

a. Excavator group
General Public Government Excavator other than Operator/subcontractor

b. Type: Road Work Pipeline Water Electric Sewer Phone/Cable
Landowner-not farming related Farming Railroad
Other liquid or gas transmission pipeline operator or their contractor
Nautical Operations Other ______________________________

c. Excavation was: Open Trench Sub-strata (boring, directional drilling, etc…)

d. Excavation was an ongoing activity (Month or longer) Yes No If Yes, Date of last contact /_________/

e. Did operator get prior notification of excavation activity?
Yes; Date received: /_______/ mo. /______/ day /_____________/ yr. No
Notification received from: One Call System Excavator Contractor Landowner

f. Was pipeline marked as result of location request for excavation? No Yes *(If Yes, check applicable items i - iv)*
- i. Temporary markings: Flags Stakes Paint
- ii. Permanent markings:
- iii. Marks were (check one) : Accurate Not Accurate
- iv. Were marks made within required time? Yes No

H4 – OTHER OUTSIDE FORCE DAMAGE

10. Fire/Explosion as primary cause of failure => Fire/Explosion cause: Man made Natural
11. Car, truck or other vehicle not relating to excavation activity damaging pipe
12. Rupture of Previously Damaged Pipe
13. Vandalism

H5 – MATERIAL AND/OR WELD FAILURES

Material

14.	Body of Pipe	=>	Dent	Gouge	Bend	Arc Burn	Other ____________
15.	Component	=>	Valve	Fitting	Vessel	Extruded Outlet	Other ____________
16.	Joint	=>	Gasket	O-Ring	Threads		Other ____________

Weld

17.	Butt	=>	Pipe	Fabrication			Other ____________
18.	Fillet	=>	Branch	Hot Tap	Fitting	Repair Sleeve	Other ____________
19.	Pipe Seam	=>	LF ERW HF ERW	DSAW SAW	Seamless Spiral	Flash Weld	Other ____________

*Complete a-g if you indicate **any** cause in part H5.*

a. Type of failure:
Construction Defect => Poor Workmanship Procedure not followed Poor Construction Procedures
Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? Yes No

c. Was part which leaked pressure tested before accident occurred? Yes, *complete d-g* No

d. Date of test: /____________/ yr. /______/ mo. /______/ day

e. Test medium: Water Inert Gas Other ______________________________

f. Time held at test pressure: /______/ hr.

g. Estimated test pressure at point of accident: ________________________ *PSIG*

H6 – EQUIPMENT

20.	Malfunction of Control/Relief Equipment	=>	Control valve	Instrumentation	SCADA	Communications
			Block valve	Relief valve	Power failure	Other ____________
21.	Threads Stripped, Broken Pipe Coupling	=>	Nipples	Valve Threads	Dresser Couplings	Other ____________
22.	Seal Failure	=>	Gasket	O-Ring	Seal/Pump Packing	Other ____________

H7 – INCORRECT OPERATION

23. Incorrect Operation

a. Type: Inadequate Procedures Inadequate Safety Practices Failure to Follow Procedures
Other ____

b. Number of employees involved who failed a post-accident test: drug test: /__________/ alcohol test /________/

H8 – OTHER

24. Miscellaneous, *describe:* ____

25. Unknown
Investigation Complete Still Under Investigation *(submit a supplemental report when investigation is complete)*

PART I – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT *(Attach additional sheets as necessary)*

Appendix D

Metallurgical Report

This document is on file at PHMSA

Appendix E

Enbridge Line 61 Control Center Operations Investigation Report

This document is on file at PHMSA