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

Principal Investigator	Molly Atkins
Region Director	R. M. Seeley
Date of Report	October 23, 2013
Subject	Failure Investigation Report – Mobil Pipe Line Company; Pegasus Pipeline, Mayflower, AR

Operator, Location, & Consequences

Date of Failure	3/29/2013
Commodity Released	Wabasca Heavy Crude Oil
City/County & State	Mayflower, Faulkner, Arkansas
OpID & Operator Name	12628, Mobil Pipe Line Company
Unit # & Unit Name	11912, AR
SMART Activity #	143154
Milepost / Location	MP 314.77/Approximately 15.5 miles south of the Conway Pump Station
Type of Failure	ERW Seam Failure
Fatalities	0
Injuries	0
Description of area impacted	Residential area
Property Damage	$57,500,000 (as of 8-15-2013)[1]

Executive Summary

On March 29, 2013, at approximately 2:37 p.m.[1], local time, a pipeline rupture occurred on the Mobil Pipe Line Company Pegasus Pipeline System, Patoka to Corsicana 20" Segment[2], in Mayflower Arkansas. The operator notified the National Response Center (NRC) on March 29, 2013 at 4:06 p.m. local time, supplemented by a 6:04 p.m. local time report, and supplemented again by a third report placed at 3:25 a.m. on March 30, 2013, establishing the volume released as somewhere between a couple thousand and ten thousand barrels of crude oil. The first PHMSA investigator arrived onsite the afternoon of March 30, 2013.

At the time of the rupture, the pipeline was transporting Wabasca heavy crude and was operating at 708 psig[1] at the location of the failure. The rupture occurred in the Northwoods Subdivision, a residential neighborhood of Mayflower, Arkansas. The subdivision and site terrain have drainage paths that lead to Lake Conway, including storm drains leading to Dawson Cove south of the main body of Lake Conway.

Initial response by local emergency responders and public officials within 30 minutes of the release is credited for preventing the flow of the released product into Lake Conway. City and county emergency responders deployed booms and constructed earth dams to stem the flow of crude oil at various locations downstream of the spill site.

The cause of the rupture was determined to have resulted from manufacturing related hook cracks that merged during the service life of the pipe and other manufacturing issues related to areas of low toughness in the heat affected zone that ultimately led to crack growth to the size where failure of the long seam occurred[3]. Contributing factors to the accident were failure of the operator's integrity management program to identify the pipe as susceptible to seam failure, and failure of the operator to carry out integrity management actions appropriate to pipe with such characteristics as further described in Appendix E to this report.

For the purposes of this report, references are made to EMPCo, as the contract operator for Mobil Pipe Line Company.

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[1] Accident Report, Form 7000.1, Number 20130151 – 17953, Dated May 26, 2013, Supplemented June 25, 2013 and August 15, 2013
[2] Line Drawing S-110B
[3] Hurst Laboratory Metallurgical Investigation Report No. 64961, Rev. 1

System Details

System Overview

The Pegasus Pipeline is approximately 859 miles in length. It originates in Patoka, Illinois and terminates in Nederland, Texas. There are 14 pump stations along the pipeline route and the current stated maximum system capacity is 90,000 BPD from Patoka to Corsicana, and 120,000 BPD south of Corsicana[4]. Normal flow is stated as 4,230 BPH.[5] The pipeline schematic is shown in Figure 1.

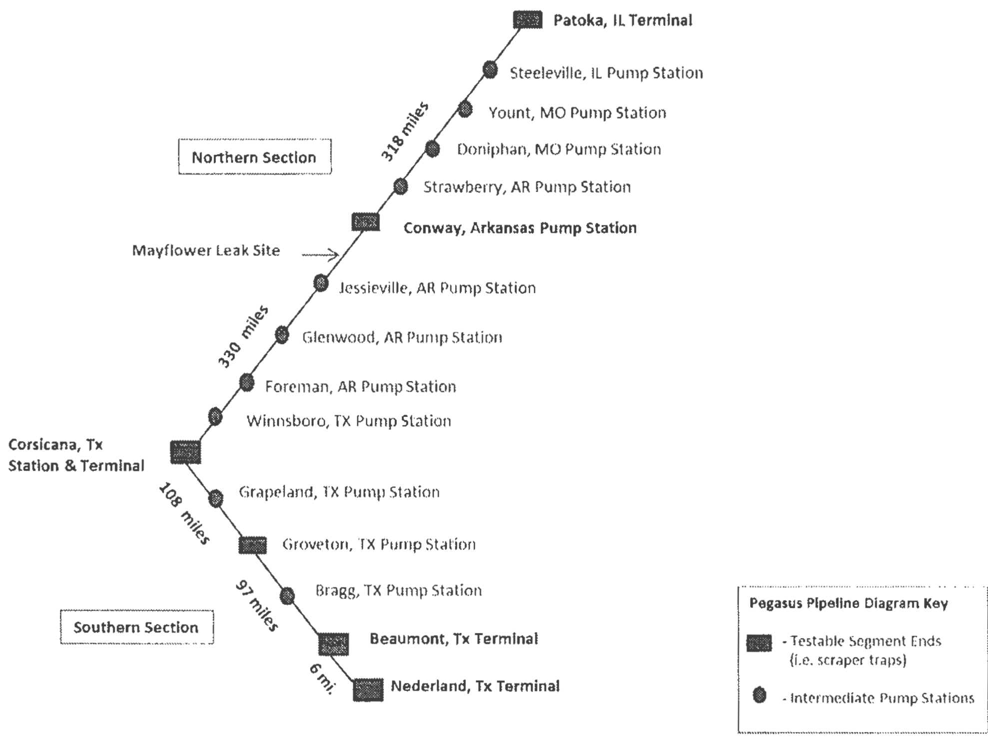

Figure 1 Pegasus Pipeline

The pipeline was originally constructed and operated as three separate pipeline systems. The first system (the Northern Section – Patoka to Corsicana) was constructed in 1947 and 1948 and consists of 648 miles of 20-inch diameter, 0.312" wall thickness (w.t.), grade API 5X-42, low frequency electric resistance welded (ERW) manufactured by Youngstown and 0.312" and 0.500" w.t. seamless pipe manufactured by National Tube. From 1948 to 2002, the Northern Section transported crude oil north from Corsicana to Patoka. The second system (Corsicana to Beaumont) was constructed in 1954 and consists of 205 miles of 20-inch diameter, grade X-46, electric flash welded pipe manufactured by A.O. Smith and 0.312" and 0.500" w.t. seamless pipe manufactured by National Tube.

From 1954 to 1995, the system transported crude oil south from Corsicana to Beaumont, Texas. The third system (Beaumont to Nederland) was constructed in 1973 and consists of 6 miles of 16-inch diameter, grade X-52, ERW pipe. The manufacturer is not known at this time. From 1973 to 1995, the third system transported crude oil north from Nederland to Beaumont. In 1995, the second system

[4] CAO Hearing presentation by EMPCo, dated 5/2/2013
[5] EMPCo Form 6.3 dated 9/21/2009 – EMPCo-PHMSA015471

reversed flow and was "tight-lined" with the third system, creating a single pipeline operation transporting crude oil north from Nederland to the hub in Corsicana (collectively, the Southern Section).

Operating History

The Patoka to Corsicana Segment was operated from a south to north flow direction following its construction in 1947 to 1948 until 2002, when it was idled and purged with nitrogen until 2006. The pipeline carried west Texas crude oil to Patoka, Illinois between 1948 and 1995. From 1995 to 2002 the line carried both west Texas crude oil and foreign crude oil (via the Gulf of Mexico) northward.

In 2005, the Southern Section reversed flow to the south. The Northern Section flow was reversed when it was returned to service in 2006, transporting crude oil towards the Gulf of Mexico from Patoka, Illinois. Prior to returning the Northern Section to service, the operator performed repairs previously identified in the 2001 baseline integrity assessment, and performed Subpart E pressure tests as the integrity reassessment and integrity confirmation for returning an idle line to service. Additionally, as a part of the reversal project, the operator commissioned a hydraulic study utilizing Mustang Engineering. The study analyzed flow rates for heavy and light crude at 66,000 barrels per day (BPD) to 93,000 BPD respectively for a system configuration that included 7 pump stations and 25 motor operated valves (MOVs).

From 2006 to the time of the accident in 2013, the Northern and Southern Sections were "tight-lined" creating a single 859-mile pipeline operation transporting product south from Patoka to Nederland. During this time the system was re-named the Pegasus Pipeline. In 2009, the capacity of the Pegasus Pipeline was expanded to its present capacity with additional/reactivated pump stations and pump units, and a hydraulic study was performed by Mustang Engineering to assess any potential surge issues and establish operating set points. The study analyzed the pipeline system configuration which was now comprised of 13 pump stations, 35 MOVs for six seasonal flow variations resulting in 210 case simulations for flow rates ranging from 87,000 BPD to 101,500 BPD. The Groveton, Texas Pump Station was added after the 2009 Hydraulic Surge Study was performed.

The MOP of the pipeline at the failure location was 865 psig[1]. The MOP was established by a Subpart E pressure test on 24 January 2006, at a test pressure of 1091 psig (adjusted for elevation difference to the failure location).[6] Prior to failure, the pipeline was reported to typically operate between 47° F and 78° F at pressures ranging between 240 psig and 820 psig. The pressure at the time of the failure was estimated to be between 702 psig and 708 psig.

Mobil Pipe Line Company is the registered owner and operator of the Pegasus Pipeline which is operated under a written service agreement by ExxonMobil Pipe Line Company (EMPCo)[7]. The operating procedures and Integrity Management Plan, as well as the other various plans required by 49 CFR 195 and 49 CFR 194 are those developed and executed by EMPCo. The applicable Facility Response Plan for the location of the pipeline rupture site is the Corsicana Response Zone, PHMSA Sequence Number 103.

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[6] Pressure Test Report for Test Section 13, Conway, AR MP 312.64 – 330.12, dated 1/24/2006
[7] EMPCo Request for Hearing (by Counsel), dated 4/12/2013

Pipe Specifications
The Pegasus Pipeline system is comprised of three distinct segments as shown in Table 1[4]:

Segment	Segment/HCA Miles	Date of Construction	Pipe Material	Manufacturer	MOP (psig)
Patoka to Corsicana	648/605.4	1947-1948	20" X42/ERW [and Seamless]	Youngstown [National Tube]	765 - 919
Corsicana to Beaumont	205/129.53	1954	20" X42/EFW [and Seamless]	A.O. Smith [National Tube]	1022 - 1144
Beaumont to Nederland	5.9/5.9	1973	16" X52/ERW	Unverified to Date	1028

Table 1 – Pegasus Pipeline Pipe Specifications

The failure section was manufactured in 1947 by Youngstown, Grade B/X42, 20" O.D. x .312" w.t., low frequency ERW seam pipe. From the metallurgical testing performed, the pipe met the composition, tensile and ultimate strength properties of both the 1947 - Grade B, and 2004 - X42, API 5L specifications) [8]

Product Specifications
The product that was being transported at the time of failure was Wabasca Heavy Crude Oil. This crude oil is named for the Wabasca area of the northern Alberta, Canada oilfield from which it originates. Most oil is produced from the Wabiskaw Sandstone, a formation equivalent to the one excavated in the Athabasca Oil Sands, but from sub-surface. Wabasca Crude typically has an API Gravity ranging from 18.5° to 21.2°, whereas in comparison medium to light crude oils have API Gravities ranging from 30° to 40° and other heavy crude oils have API Gravities ranging from 10.1° to 21.5°. Water has an equivalent API Gravity of 10°. Any petroleum product with an API Gravity **less than** 10° would have a relative density of greater than 1, and would therefore sink in water, as would be the case with ***Undiluted*** Bitumen which has an API Gravity of 8° – 10°.

The data for other various heavy crude oils produced in North America and the Gulf of Mexico indicates that whether or not the Wabasca Heavy Crude Oil was in fact obtained from conventional methods or was a "Tar Sands" crude, its properties for API Gravity, sulfur content and TAN (Total Acid Number) are relatively the same[9],

The National Academies of Science' TRB Special Report 311: *Effects of Diluted Bitumen on Crude Oil Transmission Pipelines* was issued in June 2013 wherein the central findings were:

> *The committee does not find any causes of pipeline failure unique to the transportation of diluted bitumen. Furthermore, the committee does not find evidence of chemical or*

[8] Metallurgical Analysis Report Number 51695, Hurst Laboratories, dated 6/17/2006
[9] Congressional Research Service Report R42611, dated February 21, 2013

> *physical properties of diluted bitumen that are outside of the range of other crude oils or any other aspect of its transportation by transmission pipeline that would make diluted bitumen more likely than other crude oils to cause releases.*

Further, the specific findings determined that "*Pipeline O&M practices are the same for shipments of diluted bitumen as for shipments of other crude oils. O&M practices are designed to accommodate the range of crude oils in transportation.*"

Integrity Assessment History

In Line Inspection

The Northern Section of the Pegasus Pipeline is divided into two "testable" sections for the purposes of performing in-line inspections. The first testable section extends from the Patoka, Illinois Terminal to the Conway, Arkansas Pump Station and is approximately 318 miles in length. The second testable section extends from the Conway, Arkansas Pump Station to the Corsicana Terminal and is slightly more than 330 miles in length. More than 91% of each of the two testable segment's mileage are considered an HCA, or HCA-could-affect for the purposes of the application of Pipeline Integrity Management for High Consequence Area regulations in 49 CFR 195.452. Table 2 summarizes the integrity inspection assessments performed on these sections of the Pegasus Pipeline since its restoration of service in 2006[10].

			Most Recent Integrity Assessments					
Testable Segment	**Diam (in)**	**Length (mi) HCA (mi)**	**Previous Caliper/MFL Inspection**	**Next Caliper/MFL Inspection**	**Caliper/MFL Status**	**TFI Date**	**TFI Status**	**Last Hydrotest Date**
Patoka to Conway	20	317.8 304.4	8/15/2010	8/15/2015	63 PTNI Repairs Remaining	8/15/2010	All long seam related repairs complete	2005-2006
Conway to Corsicana	20	330.4 301.0	7/21/2010	7/21/2015	43 PTNI Repairs Remaining	2/6/2013	Received portion of preliminary data. Validation digs pending	2005-2006

Table 2 – Pegasus Pipeline Northern Section Most Recent Integrity Assessments

Hydrostatic Testing

During the hydrostatic tests performed in 2005 and 2006, there were 15 test failures experienced on these two sections[11]. Appendix E, Tab F summarizes and discusses the hydrostatic test failures and the results of the metallurgical analyses performed by Hurst Metallurgical Research Laboratory, Inc. and prepared for ExxonMobil Pipeline Company.

In summary, six of the 27 test sections experienced fifteen (15) hydrostatic test failures, eleven (11) of which were related to the ERW seam, three (3) resulting from pinhole leaks in girth welds that allowed corrosion to develop over time, and one (1) failure in a section of seamless pipe that had an area of severe damage and gouging on the external surface of the pipe. The failure of the seamless pipe was the first indication to the operator that there was 0.312" wall seamless pipe in addition to the .500" wall seamless pipe on the pipeline.

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[10] Pegasus Integrity Management Schedule – EMPCo-PHMSA016173

[11] EMPCo Memo to File; Summary of Learnings from the 2005/2006 Hydrotest Failures and Root Cause Metallurgical Analysis

The CVN (Charpy V-Notch) testing values are representative of the pipe's toughness (resistance to crack propagation) and are also discussed in greater detail in Appendix E of this report. "The essential elements of a fracture-mechanics assessment as it is applied to a pipeline situation are the level of nominal tensile stress (usually the pressure-induced hoop stress), the maximum size of a longitudinally oriented defect (usually in terms of axial length and depth penetration through-the wall thickness of the pipe), and the inherent resistance of the pipe material to propagation of the defect either through the wall or along the axis of the pipe. The latter parameter is usually referred to as the "toughness" of the material.[12]" All of the 2005-2006 hydrotest failures of the ERW seam exhibited low toughness at the ERW bondline, as well as in some cases in the base metal.

Events Leading up to the Failure

The pipeline was operating under normal conditions with no pressure or operating restrictions, described by the operator as "steady state conditions," immediately prior to the rupture. There were no maintenance activities affecting the operation of the pipeline immediately prior to the rupture.

At the first pump station upstream of the rupture site (Conway Pump Station approximately 15.5 miles north of the accident site)[2], the discharge pressure was 768 psig, and the pipeline was flowing at a rate of 4,000+ BPH. At approximately 2:37 p.m. local time (Central Time Zone), the first indication that the operator had of an abnormal condition on the pipeline was when the pipeline controller on duty on Console 6 observed a low pressure alarm along with a high rate of pressure change alarm at the Arkansas River Surveillance Site located at milepost 312, just under three miles south of the rupture site.

At approximately 2:38 p.m., the pipeline controller initiated shutdown of the pipeline, achieving isolation of the rupture site from upstream pressure and supply sources at 2:53 p.m. local time. Field personnel were notified of the situation observed by the pipeline controller and responded to the scene, reaching the rupture location at 3:20 p.m. local time[1].

Emergency Response

The rupture site was in the Northwoods Subdivision, a residential neighborhood of Mayflower, Arkansas the majority of which was constructed in 2006. The subdivision and site terrain have drainage paths that lead to Lake Conway, including storm drains leading to an unnamed cove south of the main body of Lake Conway.

Initial response by local emergency responders and public officials within 30 minutes of the release aided in the prevention of the flow of the released product into Lake Conway. City and county emergency responders deployed booms and constructed earth dams to stem the flow of crude oil at various locations downstream of the spill site.

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[12] Final Report TTO Number 5, *Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation*, Michael Baker, Jr., Inc. in association with Kiefner & Associates and CorrMet Engineering Services, dated April 2004

Figure 2 Mayflower Subdivision Aerial Photos

EMPCo personnel arrived on site at 3:20 p.m. local time where they initiated their Facility Response Plan, and continued coordination with local emergency response officials. The Environmental Protection Agency (EPA) led the response coordination using a Unified Command process. Emergency officials ordered evacuations, and 22 households evacuated, and 1 household chose to stay.

Figure 3 Dawson Cove South of the Main Body of Lake Conway

The operator made an initial NRC Report on March 29, 2013 at 4:06 p.m. local time, supplemented by a 6:04 p.m. local time report, and supplemented again by a third report placed at 3:25 a.m. on March 30, 2013, establishing the volume released as somewhere between a couple thousand and ten thousand barrels of crude oil, but was undetermined at that time. There were inconsistencies in the reported times that were corrected by the 7000.1 initial report submitted on April 26, 2013. The times in the

7000.1 report matched the operator's SCADA logs. The volume released was reported in the July 25, 2013 Supplemental 7000.1 report as 5,000 barrels.

PHMSA Response

PHMSA, SW Region sent an accident investigator to the site on Saturday, March 30, 2013, followed by two more personnel on April 1, 2013, remaining on-site through April 12, 2013. The accident site was managed under Incident Command and the lead agency was the United States Environmental Protection Agency (USEPA) during the clean-up phase. PHMSA's role during the clean-up phase was on-site coordination and status situational updates until such time that the accident site was made safe and no longer considered a "hot-zone" in terms of the clean-up and product recovery activities. The accident site was made accessible and cleared for removal of the pipe on April 14, 2013. PHMSA, SW Region accident team personnel returned to the site to observe and monitor the removal and handling of the failed pipe section from the accident site. The site was excavated, the coating was removed, and the pipe was cleaned and preserved by wrapping the pipe section in plastic wrap prior to transfer to the metallurgical lab. A custody transfer protocol was used for the transportation of the pipe from the site to the laboratory that would perform the metallurgical failure investigation. PHMSA inspectors remained on site until April 17, 2013, after the pipeline replacement section installation was complete.

PHMSA issued Corrective Action Order (CAO) CPF No. 4-2013-5006H to Mobil Pipeline Company on April 2, 2013. On April 12, 2013, Mobil requested a hearing to address four items in the CAO. The hearing was held on May 2, 2013, in the PHMSA SW Region Office, and was recorded by Mobil. The CAO was confirmed in a Post-Hearing Decision issued by PHMSA on May 10, 2013, with a minor modification to Item 7 to clarify the pressure reduction pressures.

Investigation Findings & Contributing Factors

Accident Site

The accident site was in a Mayflower, Arkansas subdivision, approximately 25 miles north of Little Rock, Arkansas at Latitude 34° 57′ 49.1″ N and Longitude 92° 25′ 43.6″ W. The leak site was on the pipeline right of way between two single family dwellings. The released crude oil flowed downhill along the right of way to the street as well as further south between two adjacent houses into the street, into the stormwater drains, and ultimately to Dawson Cove south of Lake Conway. The released product did not reach Lake Conway or impact any drinking water supplies. Twenty-two households were evacuated, and there were minor impacts to flora and fauna in the immediate area. There were no reported injuries or fatalities related to the release.

Figure 4 Accident Site March 30, 2013, Looking to the Southwest – Northwoods Subdivision, Mayflower, AR

Figure 4 is a photo of the accident site on March 30, 2013. Appendix A includes an aerial view of the accident site and the various response zones and activities that were underway on March 30, 2013.

The failed pipe section was examined at the site. There was no apparent external damage, and no signs of significant internal or external metal loss. The coating was intact, and generally well adhered. The failure was a longitudinal split originating near the ERW long seam at roughly the 12:00 position, and extended on either side for a total length of approximately 22 feet along the seam and 3 inches into the base metal. The widest opening in the tear was approximately 1 and 3/8 inches.

The product was removed from the affected section of the pipeline by vacuum extraction, and the failed section was then cut from the line and prepared for transport to the metallurgical laboratory for testing, using a chain of custody protocol. Approximately 50 feet was cut from the line, sectioned into three pieces, and transported by truck to Hurst Metallurgical Research Laboratory, Inc. (Hurst) in Euless, Texas.

Figure 5 Failed Pipe Section – MP 314.77

Records Review and Personnel Interviews

PHMSA, SW Region requested operating and maintenance procedures and associated records for the Pegasus Pipeline, interviewed operating and control room personnel, and met with ExxonMobil personnel by telephone and in person to collect information that was used in the accident investigation.

A review of the operator's emergency response actions and SCADA logs indicated that the detection, response, and reporting of the release were all conducted according to the operator's plan. The shutdown of the pipeline was initiated within one minute of the first alarm, the failure section was isolated from flow within 16 minutes of the first alarm, and EMPCo personnel arrived on site 43 minutes after the first alarm.

EMPCo, as the contract operator for Mobil Pipe Line Company, carries out the integrity management decisions for the Pegasus Pipeline using the EMPCo integrity management procedures found in the ExxonMobil Pipeline Company Integrity Management Program in High Consequence Areas Manual (EMPCo IMP Manual). Investigation resulted in a detailed review of the operator's Integrity Management Program and this is covered in additional detail in Appendix E to this Report.

Metallurgical Analysis

Figure 6 – Hook Crack at Failure Site

The operator, through its metallurgical laboratory, performed various examinations and testing of the failed pipe and adjacent sections. The pipe had visible moderate corrosion pitting (maximum pit depths ranged from .021" to .037" along the pipe which are approximately 7% to 12% of the total wall thickness of the pipe) in areas of sagging/disbonded coating at the bottom of the pipe, and along areas of cracked coating, but not in the vicinity of the ERW seam. No preferential or grooving corrosion was present along the ERW seam at the 12 o'clock position.

There was no evidence of any internal corrosion on the inside surface of the pipe. The wall thickness was measured at the end points to be 0.310" to 0.321" resulting in an average calculated thickness of 0.315", with the nominal specified wall thickness as 0.312". The actual wall thickness was determined to be between 0.288" and 0.316" along the evaluated length of the pipe section when it was measured using non-destructive ultrasonic test methods.

There was no evidence of mechanical damage, or external forces that contributed to the failure at this location.

All of the test specimens taken through the pipe base metal and across the ERW seam met the tensile and ultimate stress requirements specified in both API 5L 10th and 44th Editions. The pipe met the chemical composition that was specified in API 5-L, 10th Edition at the time of the pipe manufacture, but does not meet the compositional requirements specified in the current API 5L, 44th Edition for welded pipe. Additionally, the CVN testing revealed very low toughness for the base metal and the ERW bondline. There were no minimum levels for this parameter at the time of manufacture of the pipe.

The pipe exhibited hook cracks in the ERW seam. Hook cracks are defined by API Bulletin 5TL as "metal separations resulting from imperfections at the edge of the plate or skelp, parallel to the surface, which turn toward the inside diameter or outside diameter pipe surface when the edges are upset during welding." From a metallurgical standpoint, the "defect" in the pipe is the upturned grains containing brittle martensite, which were formed during the welding process. The hook cracks occurred due to this undesirable or defective grain flow in the ERW seam.

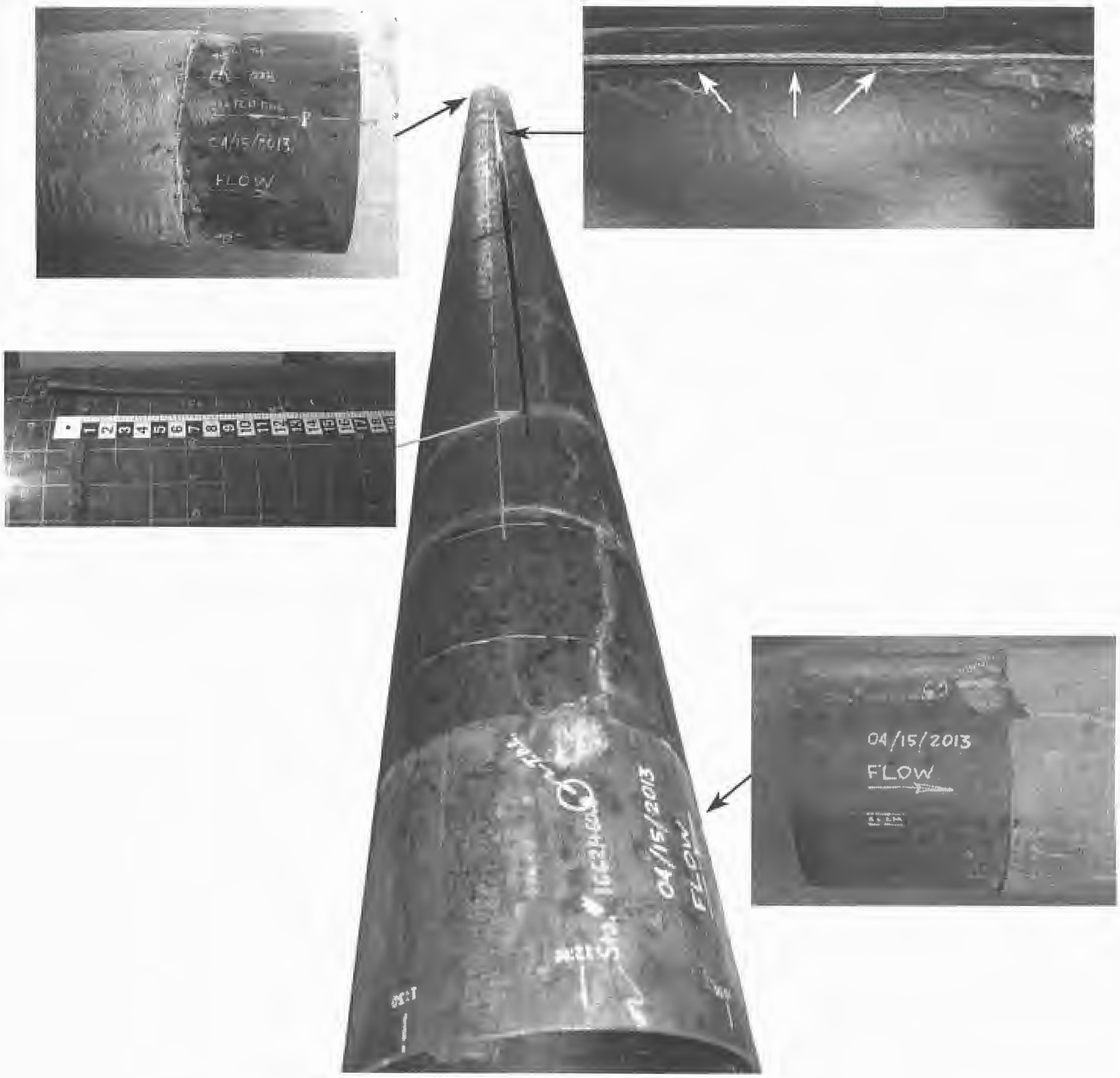


Figure 7–Photograph No. 86 – Hurst Report 64961

The detailed results of the metallurgical evaluation are found in Hurst's Report Number 64961, Rev. 1[3]. There were no definitive signs of fatigue failure exhibited in the prior hook crack areas above the final failure origin area(s) due to the brittle nature of the low toughness material and the presence of the scale or oxidation products which obscured the fracture morphology, specifically the possible presence of any microscopic fatigue striations. Brittle materials are not typically subject to high cycle fatigue failures, as they tend to fail relatively quickly from smaller defect sizes when subjected to cyclic loading. Larger defects in brittle materials typically result in rapid overload failure during testing such as the hydrotesting performed in 1991 and 2006 on this line. It may be surmised from the results of the investigation conducted by Hurst Metallurgical Research Laboratory, Inc. that the areas of relatively more ductile material interspersed within the brittle zones of the ERW seam could have fractured intermittently over time and connected with the brittle areas containing the hook cracks. The resultant crack, while shallow and tight enough to be undetectable at the time by the ILI tools used for inspection of the line, eventually reached a critical length, resulting in the failure of the low toughness ERW seam.[13]

The report documented evidence of:

> *hook cracks through multiple ductile and brittle zones, significant variance in hardness between the various zones of the ERW seam. . . tightness and depth of the hook cracks along multiple planes through the upset heat-affected zones, and . . . extremely low impact toughness and elongation properties across the ERW seam.*

The report concluded that the most likely failure scenario was:

> *"that some micro-cracking within the upset/heat-affected zones might have occurred immediately following the pipe manufacturing. The micro-cracks then likely would have merged by further cracking through the adjacent areas in the localized upset/HAZ zones during service, forming a continuous hook crack in each of the localized areas to the critical depths, at which point the remaining wall thickness, combined with the localized stress concentration and residual stresses, could no longer support the internal hoop stresses and resulted in the final failure."*

The findings of this metallurgical analysis were consistent with the previous findings of the Hurst metallurgical reports for the investigations into the hydrostatic test failures listed in Table 3.

Findings

As part of the investigation and review of documents, the following was determined:

- EMPCo did not consider this segment of piping to be susceptible to seam failure.
- EMPCo performed integrity assessments for external metal loss and mechanical damage within the prescribed time frames. However, there was not an assessment performed within the prescribed time frame that was capable of detecting seam anomalies or related defects.
- EMPCo experienced multiple failures during hydrotesting of the Northern Section of the Pegasus Pipeline with similar failure causes related to ERW seam defects, but had not experienced an in-service rupture related to ERW seam defects on the Pegasus system.
- EMPCo had experienced other in-service failures on other pipeline systems under its control caused by ERW seam defects that were also not assessed within the prescribed time frame.
- The failure was a result of manufacturing defects in the ERW long seam, as determined by metallurgical examination and testing.
- There were no signs of internal or external corrosion, or mechanical damage at the failed origin.
- There were no signs of overpressure or operational errors that influenced or contributed to the failure.
- There were no signs that the product being transported influenced or contributed to the failure .
- The operator response was appropriate and was in accordance with the operator's procedures for emergency response.
- Pressure cycling and normal operation of the pipeline, combined with the very low toughness of the ERW seam resulted in the growth of the original defects that were present at the time of manufacture until they were no longer able to withstand the operating stresses.

Conclusions

The pipe failed as a result of defects that were present from the original manufacture of the pipe. Over the life of the pipeline, the defects grew and failed when they could no longer support the internal hoop stresses, resulting in the final failure.

The integrity assessments performed by hydrostatic testing were effective in addressing similar defects as demonstrated in the 1991 and 2005-2006 hydrotests. The operator did not consider this segment of piping susceptible to seam failure and did not select a tool capable of determining the full spectrum of seam issues known to exist in the Pegasus Pipeline; therefore, the in-line inspections performed subsequent to the hydrotests did not detect the defects that existed in the failed segment of pipe.

Contributing factors in the failure of the pipeline were the operator's actions under its integrity management program where the operator determined, incorrectly, that the pipeline was not susceptible to seam failures, and as a result, failed to assess the pipeline with a method capable of addressing that specific threat within the prescribed regulatory timeframes.

Appendices

A Map and Photographs

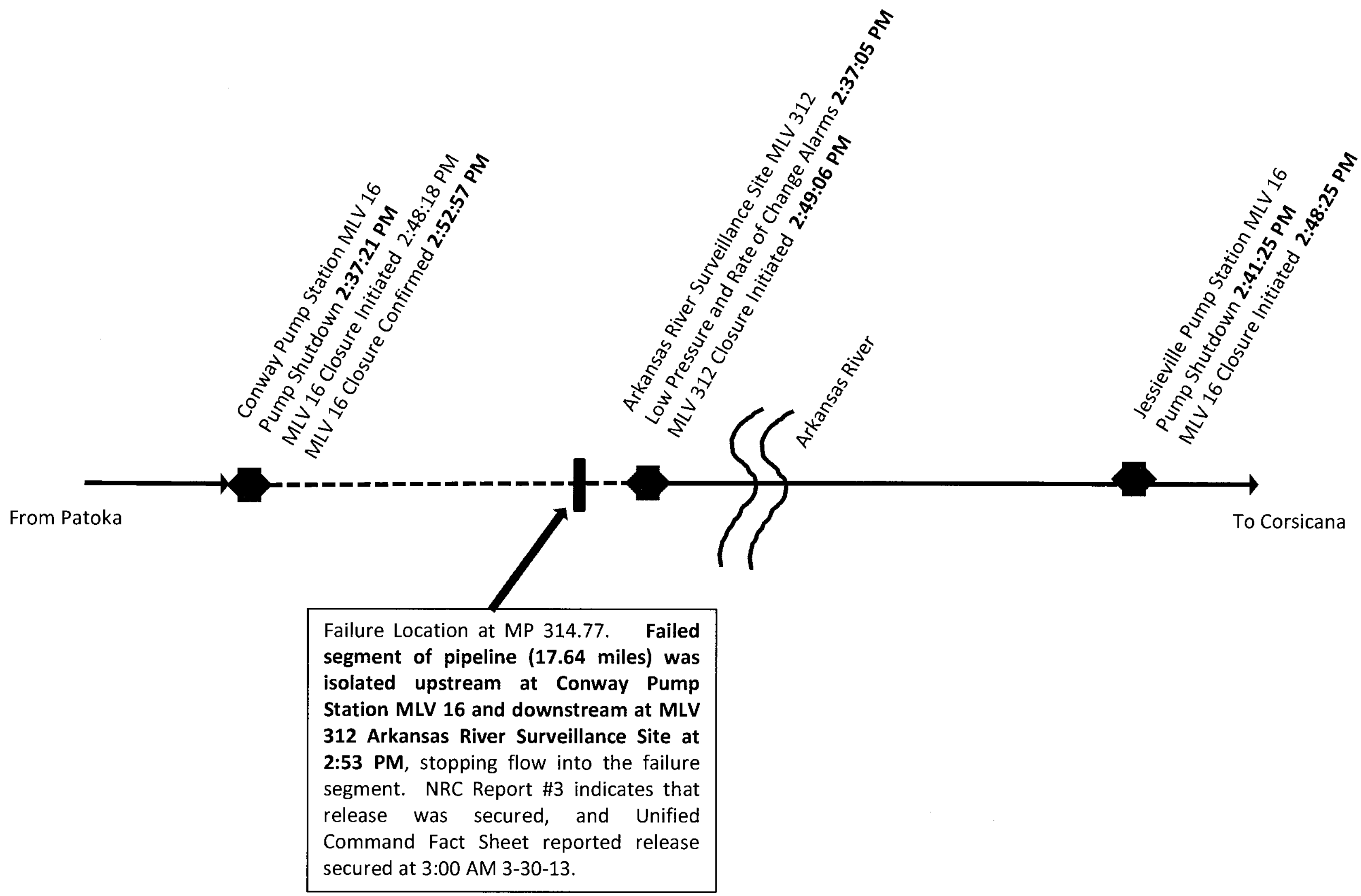
B NRC Reports

C Operator Accident/Incident Report to PHMSA

D Metallurgical Analysis

E Discussion of Contributing Factors

APPENDIX A


Conway Pump Station MLV 16
Pump Shutdown **2:37:21 PM**
MLV 16 Closure Initiated 2:48:18 PM
MLV 16 Closure Confirmed **2:52:57 PM**
Arkansas River Surveillance Site MLV 312
Low Pressure and Rate of Change Alarms **2:37:05 PM**
MLV 312 Closure Initiated **2:49:06 PM**
Arkansas River
Jessieville Pump Station MLV 16
Pump Shutdown **2:41:25 PM**
MLV 16 Closure Initiated **2:48:25 PM**
From Patoka
To Corsicana
Failure Location at MP 314.77. **Failed segment of pipeline (17.64 miles) was isolated upstream at Conway Pump Station MLV 16 and downstream at MLV 312 Arkansas River Surveillance Site at 2:53 PM**, stopping flow into the failure segment. NRC Report #3 indicates that release was secured, and Unified Command Fact Sheet reported release secured at 3:00 AM 3-30-13.

ExxonMobil Pipeline

Mayflower Pipeline Incident
Situation Status Map
March 30, 2013 @ 1400 Hrs

The Response Group
Emergency Response | Pre-Planning & Support

N

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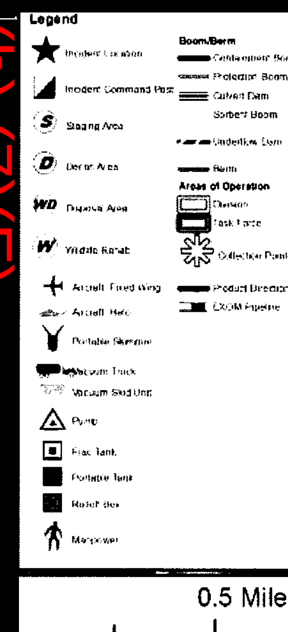

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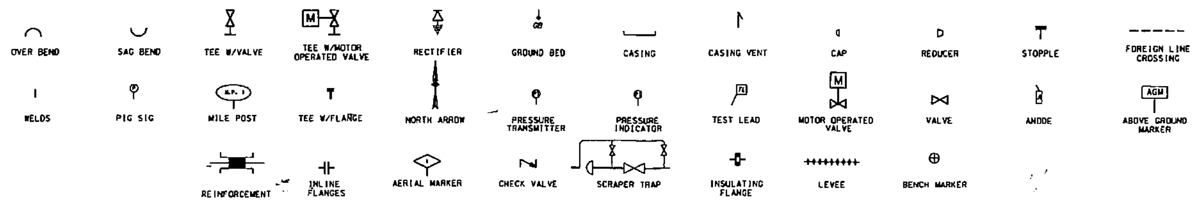


ALIGNMENT SYMBOLOGY LEGEND AND REFERENCE

NOTE: FOR COMPLETE GEOGRAPHICAL AND INVENTORY INFORMATION SEE ALIGNMENT SHEETS.

[redacted]

(b) (7)(F)

STATE OF ARKANSAS (C251778)

FLOW

TOTAL PIPE
20" = 183.51 MI.

DISPLACEMENT
20" = 314,937 BBLS

PATOKA – CORSICANA CRUDE PEGASUS SYSTEM

CONWAY – FOREMAN 20" CRUDE

COST CENTER: C251778

1948

NOTE: OPERATING SCHEMATIC ONLY
FOR COMPLETE GEOGRAPHICAL AND INVENTORY INFORMATION SEE ALIGNMENT SHEETS.

NOTE: EQUATIONS
SOME OR ALL EQUATIONS OMITTED SEE ALIGNMENT SHEETS FOR EQUATIONS MILEAGE SHOWN INCLUDES EQUATIONS

DATE LAST REVISED: MARCH 19, 2010 (HVN)
REVISION DESCRIPTION: REVERSED PER PL-18 (5369, 5375), 5-31-2009 & (5373), 3-10-2009

TOTAL ACTIVE DISPLACEMENT = 314,937 BBLS

S-110B

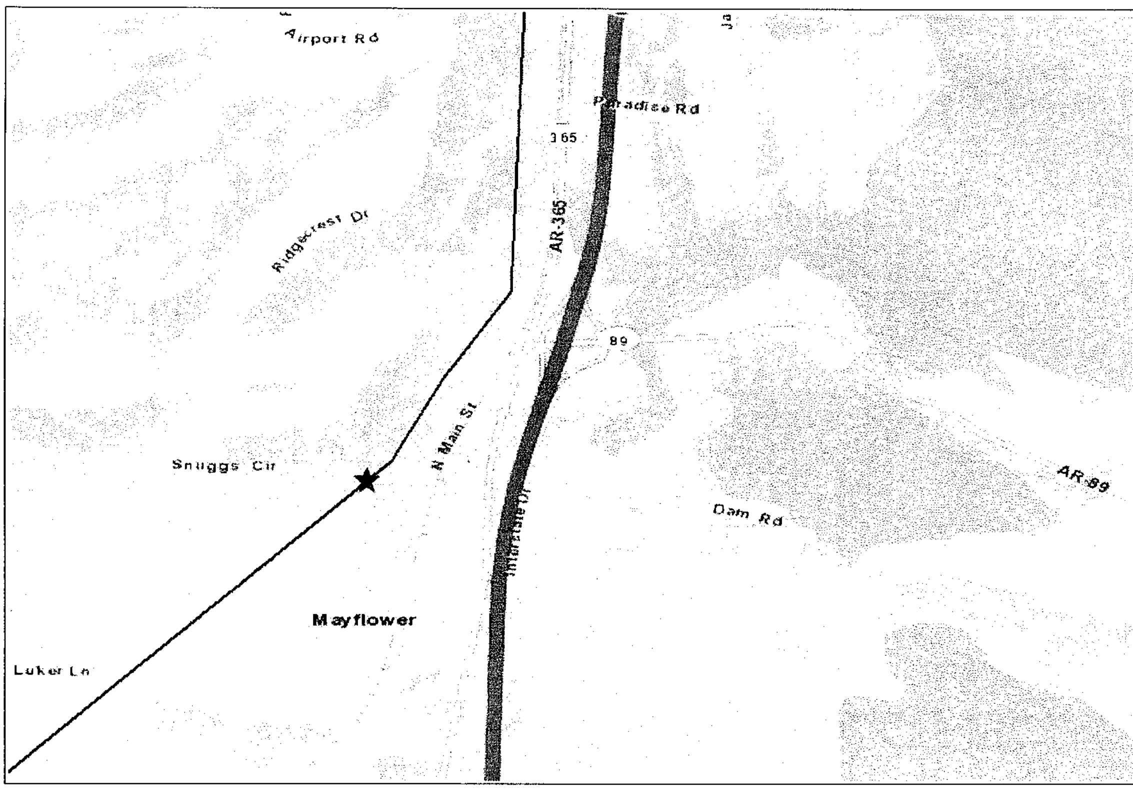
/civil/Mobil/tru/S-110

...\MobilTru\S-110\S-110B.dgn 03/24/2010 1:00:22 PM

Pipeline and Hazardous Materials Safety Administration

NATIONAL PIPELINE MAPPING SYSTEM

FOR OFFICIAL USE ONLY



Legend

Hazardous Liquid Pipelines

0 0.2 Miles

Pipelines depicted on this map represent gas transmission and hazardous liquid lines only. Gas gathering and gas distribution systems are not represented.

This map should never be used as a substitute for contacting a one-call center prior to excavation activities. Please call 811 before any digging occurs.

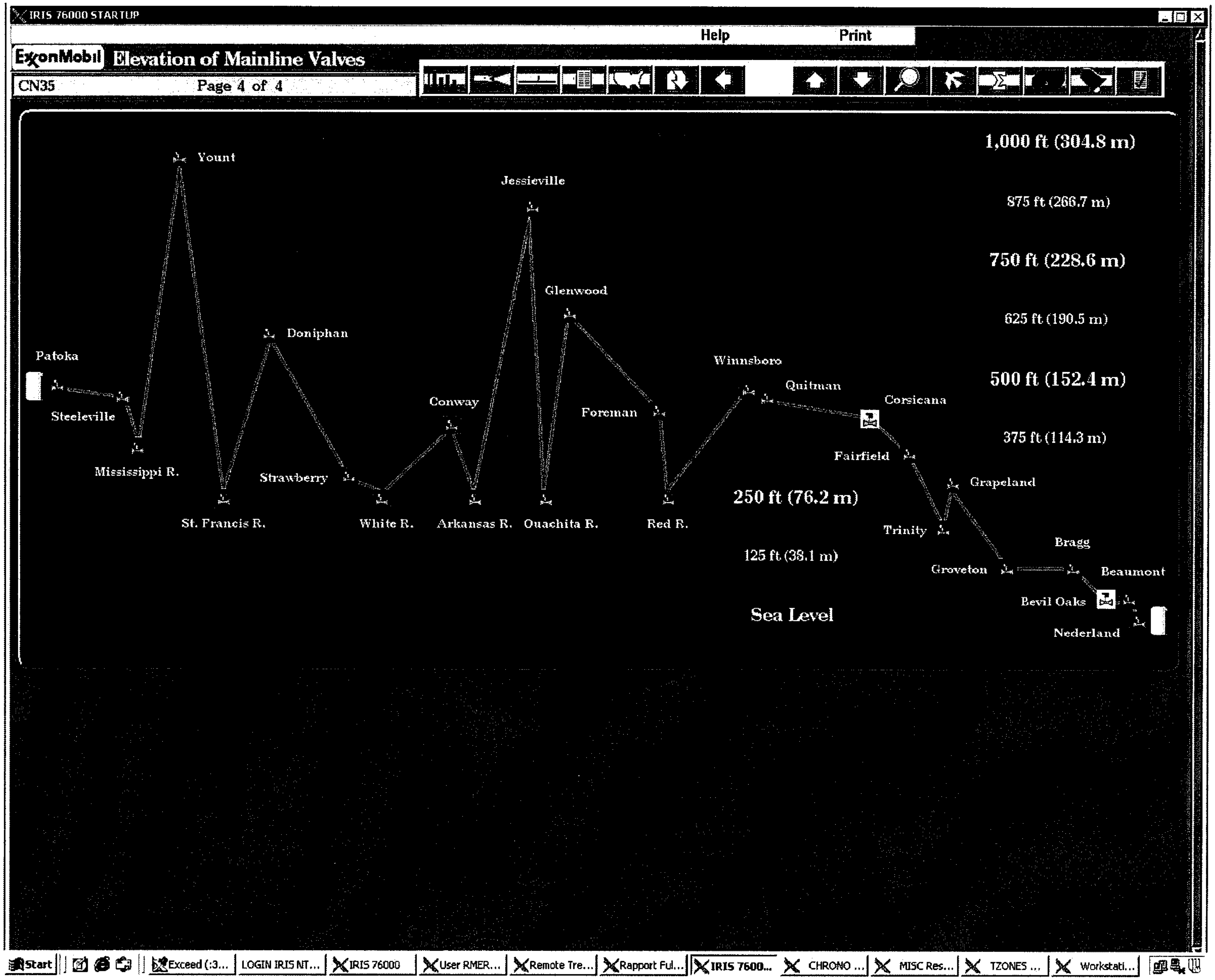
Questions regarding this map or its contents can be directed to npms-nr@mbakercorp.com.

Projection: Geographic

Datum: NAD83

Map produced by the PIMMA application at www.npms.phmsa.dot.gov

Date Printed: Mar 29, 2013



IRIS 76000 STARTUP
Help
Print
ExxonMobil
Elevation of Mainline Valves
CN35
Page 4 of 4
1,000 ft (304.8 m)
875 ft (266.7 m)
750 ft (228.6 m)
625 ft (190.5 m)
500 ft (152.4 m)
375 ft (114.3 m)
250 ft (76.2 m)
125 ft (38.1 m)
Sea Level
Patoka
Steeleville
Mississippi R.
Yount
St. Francis R.
Doniphan
Strawberry
White R.
Conway
Arkansas R.
Jessieville
Ouachita R.
Glenwood
Foreman
Red R.
Winnsboro
Quitman
Corsicana
Fairfield
Trinity
Grapeland
Groveton
Bragg
Beaumont
Bevil Oaks
Nederland
Start
Exceed (:3...
LOGIN IRIS NT...
IRIS 76000
User RMER...
Remote Tre...
Rapport Ful...
IRIS 7600...
CHRONO ...
MISC Res...
TZONES ...
Workstati...

ANGLES & BEARINGS

N 56° 45' E

16431+16 03°14' LT

N 53° 30' E

16434+08 05°24' LT

N 48° 05' E

16437+54 01°24' RT

N 49° 30' E

16447+41 04°00' RT

N 53° 30' E

16454+88 10°24' RT

N 63° 55' E

16460+54 00°23' RT

N 64° 18' E

16465+91 00°22' LT

N 63° 55' E

16470+04 01°02' LT

N 62° 52' E

16473+04 07°19' LT

N 55° 32' E

16476+89 08°16' LT

N 47° 16' E

16507+20 04°40' LT

N 42° 36' E

16625+01 17°45' LT

N 24° 51' E

16642+82 05°28' RT

N 30° 20' E

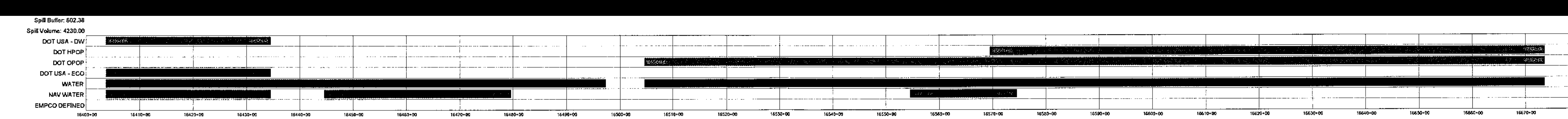
16660+95 30°14' LT

N 00° 05' E

(b) (7)(F)

[redacted]

HCA DATA BY TYPE



NO.	REVISION	DATE

LEGEND

AGMARK, AERIAL MARKER, ANODE, BLIND FLANGE, CAP, CHECK VALVE, EXPOSED PIPE, GROUND BED, INSUL. FLANGE, MILE POST, MISC FITTINGS, MOTO-OP VALVE, OVERBEND, PIG SIGNAL, PRESS TRANSMIT, RECTIFIER, REDUCER, REINFORCEMENT, SAG, STOPPLE, TEE, TEST LEAD, VALVE, LAUNCHER/RECEIVER

MAP SCALE

0 500 1000 2000

Scale: 1" = 1000'

VERT. SCALE

0 0 0 0

Scale: 1" = 0'

ExxonMobil Pipeline Company

PATOKA-CORSICANA CRUDE

CONWAY-FOREMAN S-110-3

Generated by: Mapping Dept.

Print Date: 10/30/12

Date Revised: (No revisions)

Rev. Number: Revision 2.0

Dwg. No.
S-110-3-HCA-6527-029 OF 37

The location of pipeline facilities as shown hereon must be considered as approximate only. Before digging or for an exact location please contact your state's underground utility location service.

ExxonMobil

APPENDIX B

PHMSA Pipeline & Hazardous Materials Safety Administration (Version 4.0.0 PROD)

HMIS->INCIDENTS->TELEPHONICS

Rules of Behavior Home Logout Menu

[Return to Search]

NRC Number: 1042466
Call Date: 03/29/2013 **Call Time:** 17:06:16

Caller Information

First Name:	LARRY	Last Name:	HAWTHORNE
Company Name:	EXXON MOBIL PIPELINE		
Address:	800 BELL ST.		
City:	HOUSTON	State:	TX
Country:	USA	Zip:	
Phone 1:	9038790313	Phone 2:	
Organization Type:	PRIVA	Is caller the spiller?	(•) Yes ( ) No ( ) No Response
Confidential:	( ) Yes (•) No ( ) No Response		

Discharger Information

First Name:	LARRY	Last Name:	HAWTHORNE
Company Name:	EXXON MOBIL PIPELINE		
Address:	800 BELL ST.		
City:	HOUSTON	State:	TX
Country:	USA	Zip:	
Phone 1:	9038790313	Phone 2:	
Organization Type:	PRIVA		

Spill Information

State:	AR	County:	FAULKNER
Nearest City:	MAYFLOWER	Zip Code:	

Location

50 STARLIGHT

Spill Date:	03/29/2013 (mm/dd/yyyy)	Spill Time:	13:15:00 (24hh:mm:ss)
DTG Type:	<- Select DTG Type ->		
Incident Type	ALL	Reported Incident Type	PIPELINE

Description

CALLER STATED THAT THEY HAD A PRESSURE DROP ON A PIPELINE. CALLER STATED THAT AN UNKNOWN AMOUNT OF CRUDE OIL HAS BEEN DISCHARGED.

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
OIL: CRUDE	OIL	0 UNKNOWN AMOUNT	

Medium Type: <- Select Medium Type

Additional Medium Information:

GROUND

Injuries:		Fatalites:	
Evacuations:	Yes No Unknown	No. of Evacuations:	
Damages:	Yes No Unknown	Damage Amount:	
Federal Agency Notified:	Yes No Unknown	State Agency Notified:	Yes No Unknown
Other Agency Notified:	Yes No Unknown		

Remedial Actions

OSRO IS EN ROUTE TO THE SITE.

Additional Info

Latitude

Degrees: 34	Minutes: 57	Seconds: 49	Quadrant: N

Longitude

Degrees: 92	Minutes: 25	Seconds: 44	Quadrant: W
Distance from City:		Direction:	
Section:		Township:	
Range:		Milepost:	

Rescinded **Comments** (max 250 characters)

<< Previous 1..1 of 3 Next >>

PHMSA Pipeline & Hazardous Materials Safety Administration (Version 4.0.0 PROD)

HMIS->INCIDENTS->TELEPHONICS

Rules of Behavior Home Logout Menu

[Return to Search]

NRC Number: 1042476
Call Date: 03/29/2013 **Call Time:** 19:04:32

Caller Information

First Name:	THAD	Last Name:	MASSENGALE
Company Name:	EXXON MOBIL PIPELINE		
Address:	800 BELL ST.		
City:	HOUSTON	State:	TX
Country:	USA	Zip:	
Phone 1:	9038790313	Phone 2:	
Organization Type:	PRIVA	Is caller the spiller?	◉Yes ○No ○No Response
Confidential:	○Yes ◉No ○No Response		

Discharger Information

First Name:	THAD	Last Name:	MASSENGALE
Company Name:	MOBIL PIPELINE		
Address:	800 BELL ST.		
City:	HOUSTON	State:	TX
Country:	USA	Zip:	
Phone 1:	9038790313	Phone 2:	
Organization Type:	PRIVA		

Spill Information

State:	AR	County:	FAULKNER
Nearest City:	MAYFLOWER	Zip Code:	

Location

SEE LAT AND LONG

Spill Date:	03/29/2013 (mm/dd/yyyy)	Spill Time:	15:20:00 (24hh:mm:ss)
DTG Type:	<- Select DTG Type ->		
Incident Type	ALL	Reported Incident Type	PIPELINE

Description

CALLER STATED THAT THERE WAS A RELEASE OF AN UNKNOWN AMOUNT OF CRUDE OIL FROM A TRANSMISSION PIPELINE. THE CAUSE IS UNKNOWN. CALLER ALSO STATED THAT THIS INCIDENT MAY BE A SIGNIFICANT MATERIAL RELEASE BUT THE AMOUNT IS UNKNOWN AT THIS TIME. THIS REPORT IS IN REFERENCE TO NRC REPORT NUMBER 1042466.

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
OIL: CRUDE	OIL	0 UNKNOWN AMOUNT	0 UNKNOWN AMOUNT

Medium Type: <- Select Medium Type

Additional Medium Information:

Injuries:		Fatalites:	
Evacuations:	Yes (selected) No Unknown	No. of Evacuations:	
Damages:	Yes No (selected) Unknown	Damage Amount:	
Federal Agency Notified:	Yes No Unknown (selected)	State Agency Notified:	Yes No Unknown (selected)
Other Agency Notified:	Yes No Unknown (selected)		

Remedial Actions

SHUTDOWN SYSTEM AND ALL OF THE VALVES ARE CLOSED.

Additional Info

Latitude

Degrees: 34	Minutes: 57	Seconds: 49	Quadrant: N

Longitude

Degrees: 92	Minutes: 25	Seconds: 43	Quadrant: W
Distance from City:		Direction:	
Section:		Township:	
Range:		Milepost:	

Rescinded **Comments** (max 250 characters)

<< Previous 2..2 of 3 Next >>

PHMSA Pipeline & Hazardous Materials Safety Administration (Version 4.0.0 PROD)

HMIS->INCIDENTS->TELEPHONICS

Rules of Behavior Home Logout Menu

[Return to Search]

NRC Number: 1042498
Call Date: 03/30/2013 **Call Time:** 04:25:32

Caller Information

First Name:	THAD	Last Name:	MASSENGALE
Company Name:	EXXON MOBIL PIPELINE		
Address:	800 BELL ST.		
City:	HOUSTON	State:	TX
Country:	USA	Zip:	
Phone 1:	9038790313	Phone 2:	
Organization Type:	PRIVA	Is caller the spiller?	(•) Yes ( ) No ( ) No Response
Confidential:	( ) Yes (•) No ( ) No Response		

Discharger Information

First Name:	THAD	Last Name:	MASSENGALE
Company Name:	EXXON MOBIL PIPELINE		
Address:	800 BELL ST.		
City:	HOUSTON	State:	TX
Country:	USA	Zip:	
Phone 1:	9038790313	Phone 2:	
Organization Type:	PRIVA		

Spill Information

State:	AR	County:	FAULKNER
Nearest City:	MAYFLOWER	Zip Code:	

Location

50 STARLIGHT

Spill Date:	03/29/2013 (mm/dd/yyyy)	Spill Time:	13:15:00 (24hh:mm:ss)
DTG Type:	<- Select DTG Type ->		
Incident Type	ALL	Reported Incident Type	PIPELINE

Description

THIS IS AN UPDATED REPORT, REFER TO NRC REPORT #1042466. THE AMOUNT RELEASED HAS YET TO BE DETERMINED POTENTIALLY A FEW THOUSAND BARRELS UP TO 10,000 BARRELS HAVE BEEN DISCHARGED. THE CALLER STATED THAT PRODUCT HAS RELEASED INTO FLUME PIPES AND INTO A POND, A TRIBUTARY OF LAKE CONWAY.

INITIAL REPORT: CALLER STATED THAT THEY HAD A PRESSURE DROP ON A PIPELINE. CALLER STATED THAT AN UNKNOWN AMOUNT OF CRUDE OIL HAS BEEN DISCHARGED.

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
OIL: CRUDE	OIL	0 UNKNOWN AMOUNT	0 UNKNOWN AMOUNT

Medium Type: <- Select Medium Type

Additional Medium Information:

/ CATCH POND

Injuries:		Fatalites:	
Evacuations:	◉ Yes ○ No ○ Unknown	No. of Evacuations:	
Damages:	○ Yes ○ No ◉ Unknown	Damage Amount:	
Federal Agency Notified:	○ Yes ○ No ◉ Unknown	State Agency Notified:	○ Yes ○ No ◉ Unknown
Other Agency Notified:	○ Yes ○ No ◉ Unknown		

Remedial Actions

DAMMED OFF THE AREA, VAC TRUCKS & FRAC TANKS AND ON-SCENE, CREWS ARE REMEDIATING THE POND.

Additional Info

ADDITIONAL INVESTIGATION WILL BE CONDUCTED IN THE DAYLIGHT.

Latitude

Degrees:	Minutes:	Seconds:	Quadrant:

Longitude

Degrees:	Minutes:	Seconds:	Quadrant:
Distance from City:		Direction:	
Section:		Township:	
Range:		Milepost:	

☐ Rescinded **Comments** (max 250 characters)

<< Previous 3..3 of 3 << Save >>

APPENDIX C

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0047 EXPIRATION DATE: 01/31/2014

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	04/26/2013
	No.	20130151 - 18227 (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. Public reporting for this collection of information is estimated to be approximately 10 hours per response (5 hours for a small release), including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

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 PHMSA Pipeline Safety Community Web Page at* http://www.phmsa.dot.gov/pipeline.

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	Original:	Supplemental:	Final:
		Yes	

Last Revision Date:	06/25/2013
1. Operator's OPS-issued Operator Identification Number (OPID):	12628
2. Name of Operator	MOBIL PIPE LINE COMPANY
3. Address of Operator:	
3a. Street Address	800 BELL STREET, Room 623F
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code	77002
4. Local time *(24-hr clock)* and date of the Accident:	03/29/2013 14:37
5. Location of Accident:	
Latitude:	34.96406
Longitude:	-92.42859
6. National Response Center Report Number (if applicable):	1042466
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	03/29/2013 16:06
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil
- Specify Commodity Subtype:	
- If "Other" Subtype, Describe:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend: %:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend (e.g. B2, B20, B100): B	
9. Estimated volume of commodity released unintentionally (Barrels):	5,000.00
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	
11. Estimated volume of commodity recovered (Barrels):	2,000.00
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. Workers working on the right-of-way, but NOT associated with this Operator	
12e. General public	
12f. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	

13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	03/29/2013 14:52
14b. Local time pipeline/facility restarted:	
- Still shut down? (* Supplemental Report Required)	Yes
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	83
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident:	03/29/2013 14:38
18b. Local time Operator resources arrived on site:	03/29/2013 15:20
PART B - ADDITIONAL LOCATION INFORMATION	
1. Was the origin of Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	Arkansas
3. Zip Code:	72106
4. City	Mayflower
5. County or Parish	Faulkner
6. Operator-designated location:	Survey Station No.
Specify:	16621+46
7. Pipeline/Facility name:	Pegasus 20 inch
8. Segment name/ID:	Conway to Jessieville
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	24
12. Did Accident occur in a crossing?	No
- If Yes, specify below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	
PART C - ADDITIONAL FACILITY INFORMATION	
1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Pipe

- If Pipe, specify:	Pipe Seam
3a. Nominal diameter of pipe (in):	20
3b. Wall thickness (in):	.312
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	42,000
3d. Pipe specification:	5LX-42
3e. Pipe Seam , specify:	Longitudinal ERW - Low Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	Youngstown
3g. Year of manufacture:	1947
3h. Pipeline coating type at point of Accident, specify:	Coal Tar
- If Other, Describe:	
- If Weld, including heat-affected zone, specify:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	1947
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other, Describe:	
Approx. size: in. (widest opening) by	1.5
in. (length circumferentially or axially)	267.5
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	Yes
1a. If Yes, specify all that apply:	
- Fish/aquatic	Yes
- Birds	Yes
- Terrestrial	Yes
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	Yes
4. Anticipated remediation:	Yes
4a. If Yes, specify all that apply:	
- Surface water	Yes
- Groundwater	
- Soil	Yes
- Vegetation	Yes
- Wildlife	Yes
5. Water contamination:	Yes
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	Yes
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	2,000.00
5c. Name of body of water, if commonly known:	Unnamed ditches and isolated area of the cove south of Lake Conway, Arkansas
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	Yes
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	Yes
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	

Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- High Population Area:	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	Yes
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated Property Damage:	
8a. Estimated cost of public and non-Operator private property damage	$ 0
8b. Estimated cost of commodity lost	$ 500,000
8c. Estimated cost of Operator's property damage & repairs	$ 1,000,000
8d. Estimated cost of Operator's emergency response	$ 44,000,000
8e. Estimated cost of Operator's environmental remediation	$ 0
8f. Estimated other costs	$ 2,000,000
Describe:	Temporary housing and living expences for affected residences
8g. Total estimated property damage (sum of above)	$ 47,500,000

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	708.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	865.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5e. below)*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	95,040
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? *(select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No

- If Yes, Which operational factors complicate execution? *(select all that apply)*	
- Excessive debris or scale, wax, or other wall buildup	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
- If Yes:	
7a. Was it operating at the time of the Accident?	
7b. Was it fully functional at the time of the Accident?	
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Guard Patrol by Operator or its contractor" is selected in Question 8, specify the following:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, but the investigation of the control room and/or controller actions has not yet been completed by the operator (Supplemental Report Required)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	
- Investigation identified no controller issues	
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	Yes
- If Yes:	
1a. Specify how many were tested:	2
1b. Specify how many failed:	0
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G5 - Material Failure of Pipe or Weld
G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column	
External Corrosion:	
Internal Corrosion:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
□4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	

- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G2 - Natural Force Damage - only one sub-cause can be picked from shaded left-handed column	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	

G3 - Excavation Damage - only one sub-cause can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	

4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	

- If Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation:	
- If Electrical Arcing from Other Equipment or Facility:	
- If Previous Mechanical Damage NOT Related to Excavation:	
Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	

Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	
G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column	
Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	Original Manufacturing-related (NOT girth weld or other welds formed in the field)
1. The sub-cause selected below is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	Yes
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Original Manufacturing-related (NOT girth weld or other welds formed in the field):	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	Yes
- If Other, Describe:	Investigating other possible contributing factors.
- If Environmental Cracking-related:	
3. Specify:	
- Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	Yes
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	Yes
- If Other, Describe:	Investigating other possible contributing factors.
5. Has one or more internal inspection tool collected data at the point of the Accident?	Yes
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	Yes
Most recent year run:	2010
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	Yes
Most recent year run:	2010
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	

- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	Yes
Most recent year run:	2012
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	Yes
- If Yes:	
Most recent year tested:	2006
Test pressure (psig):	1,082.00
7. Has one or more Direct Assessment been conducted on the pipeline segment?	No
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	No
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Pump), Tank Plate, or other Material:	
- If Other Equipment Failure:	
5. Describe:	

Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage	No
Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	No
1. Specify:	
- If Other, Describe:	
Valve Left or Placed in Wrong Position, but NOT Resulting in a Tank, Vessel, or Sump/Separator Overflow or Facility Overpressure	No
Pipeline or Equipment Overpressured	No
Equipment Not Installed Properly	No
Wrong Equipment Specified or Installed	No
Other Incorrect Operation	No
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	
G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column	
Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	

2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

This incident is currently under investigation.
Emergency Response and Environmental Remediation costs are combined in section D (8d & 8e).

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Thad Massengale
Preparer's Title	Pipeline Safety Advisor
Preparer's Telephone Number	7136562258
Preparer's E-mail Address	thad.massengale@exxonmobil.com
Preparer's Facsimile Number	7136568232
Authorized Signature's Name	Mark D. Weesner
Authorized Signature Title	SHE Manager
Authorized Signature Telephone Number	7136560227
Authorized Signature Email	mark.d.weesner@exxonmobil.com
Date	06/25/2013

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0047 EXPIRATION DATE: 01/31/2014

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	04/26/2013
	No.	20130151 - 17953 (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. Public reporting for this collection of information is estimated to be approximately 10 hours per response (5 hours for a small release), including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

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 PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	Original:	Supplemental:	Final:
	Yes		

Last Revision Date:	
1. Operator's OPS-issued Operator Identification Number (OPID):	12628
2. Name of Operator	MOBIL PIPE LINE COMPANY
3. Address of Operator:	
3a. Street Address	800 BELL STREET, Room 623F
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code	77002
4. Local time *(24-hr clock)* and date of the Accident:	03/29/2013 14:37
5. Location of Accident:	
Latitude:	34.96406
Longitude:	-92.42859
6. National Response Center Report Number (if applicable):	1042466
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	03/29/2013 16:06
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil
- Specify Commodity Subtype:	
- If "Other" Subtype, Describe:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend: %:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend (e.g. B2, B20, B100): B	
9. Estimated volume of commodity released unintentionally (Barrels):	5,000.00
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	
11. Estimated volume of commodity recovered (Barrels):	2,000.00
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. Workers working on the right-of-way, but NOT associated with this Operator	
12e. General public	
12f. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	

13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	03/29/2013 14:52
14b. Local time pipeline/facility restarted:	
- Still shut down? (* Supplemental Report Required)	Yes
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	83
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident:	03/29/2013 14:38
18b. Local time Operator resources arrived on site:	03/29/2013 15:20

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	Arkansas
3. Zip Code:	72106
4. City	Mayflower
5. County or Parish	Faulkner
6. Operator-designated location:	Survey Station No.
Specify:	16621+46
7. Pipeline/Facility name:	Pegasus 20 inch
8. Segment name/ID:	Conway to Jessieville
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	24
12. Did Accident occur in a crossing?	No
- If Yes, specify below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Pipe

- If Pipe, specify:	Pipe Seam
3a. Nominal diameter of pipe (in):	20
3b. Wall thickness (in):	.312
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	42,000
3d. Pipe specification:	5LX-42
3e. Pipe Seam , specify:	Longitudinal ERW - Low Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	Youngstown
3g. Year of manufacture:	1947
3h. Pipeline coating type at point of Accident, specify:	Coal Tar
- If Other, Describe:	
- If Weld, including heat-affected zone, specify:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	1947
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other, Describe:	
Approx. size: in. (widest opening) by	1.5
in. (length circumferentially or axially)	267.5
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	Yes
1a. If Yes, specify all that apply:	
- Fish/aquatic	Yes
- Birds	Yes
- Terrestrial	Yes
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	Yes
4. Anticipated remediation:	Yes
4a. If Yes, specify all that apply:	
- Surface water	Yes
- Groundwater	
- Soil	Yes
- Vegetation	Yes
- Wildlife	Yes
5. Water contamination:	Yes
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	Yes
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	2,000.00
5c. Name of body of water, if commonly known:	Unnamed ditches and isolated area of the cove south of Lake Conway, Arkansas
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	Yes
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	Yes
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	

Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- High Population Area:	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	Yes
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated Property Damage:	
8a. Estimated cost of public and non-Operator private property damage	$ 0
8b. Estimated cost of commodity lost	$ 500,000
8c. Estimated cost of Operator's property damage & repairs	$ 1,000,000
8d. Estimated cost of Operator's emergency response	$ 13,600,000
8e. Estimated cost of Operator's environmental remediation	$ 0
8f. Estimated other costs	$ 1,300,000
Describe:	Temporary housing and living expences for affected residences
8g. Total estimated property damage (sum of above)	$ 16,400,000

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	708.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	873.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5e. below)*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	95,040
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation?	*(select all that apply)*
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No

- If Yes, Which operational factors complicate execution? (*select all that apply*)	
- Excessive debris or scale, wax, or other wall buildup	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
- If Yes:	
7a. Was it operating at the time of the Accident?	
7b. Was it fully functional at the time of the Accident?	
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Guard Patrol by Operator or its contractor" is selected in Question 8, specify the following:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, but the investigation of the control room and/or controller actions has not yet been completed by the operator (Supplemental Report Required)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	
- Investigation identified no controller issues	
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	Yes
- If Yes:	
1a. Specify how many were tested:	2
1b. Specify how many failed:	0
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G8 - Other Incident Cause

G1 - Corrosion Failure - only one sub-cause can be picked from shaded left-hand column

External Corrosion:	
Internal Corrosion:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
☐4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	

- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	

4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well)*:	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage *- only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	

- If Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation:	
- If Electrical Arcing from Other Equipment or Facility:	
- If Previous Mechanical Damage NOT Related to Excavation:	
Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	

Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	
G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column	
Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-cause selected below is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Original Manufacturing-related (NOT girth weld or other welds formed in the field):	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: *(select all that apply)*:	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	

- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Pump), Tank Plate, or other Material:	
- If Other Equipment Failure:	
5. Describe:	

Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage	No
Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	No
1. Specify:	
- If Other, Describe:	
Valve Left or Placed in Wrong Position, but NOT Resulting in a Tank, Vessel, or Sump/Separator Overflow or Facility Overpressure	No
Pipeline or Equipment Overpressured	No
Equipment Not Installed Properly	No
Wrong Equipment Specified or Installed	No
Other Incorrect Operation	No
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	
G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column	
Other Accident Cause – Sub-Cause:	Unknown
- If Miscellaneous:	
1. Describe:	
- If Unknown:	

2. Specify:	Still under investigation, cause of Accident to be determined* (*Supplemental Report required)

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

This incident is currently under investigation.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Date	04/26/2013

APPENDIX D

METALLURGICAL INVESTIGATION OF A FRACTURED SECTION OF THE 20" O.D. PIPELINE AT MILEPOST 314.77 IN THE CONWAY TO CORSICANA SEGMENT OF THE PEGASUS CRUDE OIL PIPELINE

REPORT NO. 64961, REV. 1

Prepared for
ExxonMobil Pipeline Company and the
Pipeline and Hazardous Materials Safety Administration
pursuant to Corrective Action Order CPF 4-2013-5006H

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METALLURGICAL INVESTIGATION OF A FRACTURED SECTION OF THE 20" O.D. PIPELINE AT MILEPOST 314.77 IN THE CONWAY TO CORSICANA SEGMENT OF THE PEGASUS CRUDE OIL PIPELINE

1.0 INTRODUCTION

1.1 Brief Narrative of the Incident

On March 29, 2013 at 2:37 pm CST, a drop in pressure was detected within the Pegasus Pipeline of the Conway to Corsicana line segment by ExxonMobil Pipeline Company (EMPCo) at their Operations Control Center in Houston, Texas. The cause of the pressure drop was the rupture of a section of the pipeline at Milepost 314.77 in Mayflower, Arkansas. The operating pressure at the time of failure was estimated to be between 702 psig and 708 psig.

1.2 Scope of the Investigation

Hurst Metallurgical Research Laboratory, Inc. (HurstLab) was retained by EMPCo, with approval by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA), to provide technical support in the investigation of the failed section of the pipeline, as well as conduct and direct the required metallurgical tests to determine, if possible, the root cause of the failure, pursuant to Corrective Action Order CPF 4-2013-5006H.

The investigation of the cracked section of the pipeline conducted by HurstLab is a joint effort by various staff members of the Laboratory, which includes some of the report writing and analysis conducted by Susan Dalrymple-Ely, Materials Analyst and metallurgical tests conducted by Clint Myers, Staff Metallurgist of the Laboratory. The investigative effort made by this Laboratory also includes a review of the UT data and SEM fractographs provided by approved vendors.

The investigation conducted by this Laboratory is primarily based on the tests and analyses performed in accordance with the approved test protocol, review of the available information, and research conducted by this Laboratory. We reserve the right to change, amend, or omit our opinions, as warranted, based upon any additional information or further test results that may be obtained or made available to this Laboratory.

1.3 Development of Test Protocol

On April 13, 2013, a preliminary metallurgical test protocol was development by HurstLab following the general guideline entitled “Metallurgical Laboratory Examination Protocol” dated 05/08/2007 for metallurgical failure investigation of pipeline prepared by PHMSA. Following various revisions that were made to incorporate the changes requested by PHMSA, a protocol entitled “Pegasus Line - Conway to Corsicana M.P. 314.77, Mechanical and Metallurgical Testing and Failure Analysis Protocol”, referenced as Test Protocol Rev. 4, CPF No. 4-2013-5006H, Amended 4/18/13, was developed and was approved by PHMSA. A copy of the final approved protocol is presented in Appendix I.

2.0 BACKGROUND INFORMATION

2.1 Pipe Manufacturing and Coating

2.1.1 The subject section of the 20" Patoka to Corsicana #1-20" North Pipeline, the segment from Conway to Corsicana, consisted of approximately 50' long sections of 20" O.D. x 0.312" thick wall DC Electric Resistance Welded (ERW) pipe that was manufactured in 1947 and 1948 by Youngstown Sheet and Tube Company in Youngstown, Ohio. The welded pipe was manufactured from Open Hearth Steel meeting Grade B mechanical requirements.

2.1.2 The O.D. surface of the pipeline was coated with some type of a viscous bitumen or coal-tar coating, on top of which was a layer of somewhat harder but more brittle fibrous coating. No details concerning the coating type or process were available. The pipeline had reportedly been impressed current cathodically protected since installation, with possible anodes as well. The weight of the coated pipe was reported to be 65.71 lbf/ft.

2.2 Inspection and Service History

2.2.1 The subject section of pipeline was placed in service in 1948, and was buried approximately 3' below ground in native sandy clay soil. The pipeline carried crude oil from west Texas to Patoka, Illinois between 1948 and 1995. From 1995 to 2002 the line carried both west Texas crude oil and foreign crude oil (via the Gulf of Mexico) northward. In December 2002 the line was purged and idled with nitrogen. The pipeline containing the subject section of the pipe was successfully hydrostatic tested on January 24, 2006 at 1082 psig, which established a calculated MAOP of 866 psig at the failure location, based upon the Arkansas River ROV test site pressure at 1091 psig adjusted for elevation difference to the failure location. The line was then placed back in service transporting crude oil south towards the Gulf of Mexico, and remained in service up until the time of the failure.

2.2.2 Prior to failure, the pipeline was reported to typically operate between 47°F and 78° at pressures ranging between 240 psig and 820 psig. The pressure at the time of the failure was estimated to be between 702 psig and 708 psig. The fractured segment of the pipeline was located in a cleared right-of-way at the edge of a subdivision. No trees, roads, or buildings were located directly above the pipeline where the fracture occurred. As shown in Photograph No. 1, two (2) homes were built in close proximity to the pipeline, with driveways crossing over the pipeline at two (2) points downstream of the fractured segment. During construction of the homes, the pipeline may have experienced vehicle loadings caused by construction equipment and/or vehicles crossing the pipeline at multiple locations, including over the fractured segment. There was no indication of construction, digging, localized flooding, or other ground movements in the area of the fractured segment occurring during or immediately prior to the pipeline rupture.

2.3 Specifications

2.3.1 At the request of EMPCo, the subject pipe was compared to two (2) versions of the API 5L specification throughout this report, both the edition that was in effect at the time the pipe was manufactured, and the current edition of said specification, both of which are detailed below.

2.3.1.1 At the time the pipe was manufactured in 1947 and 1948, the specification in effect was API STD. 5-L, 10^{th} Edition, August 1945. Per this specification, the smelting type of steel was reportedly Open Hearth Steel, the pipe was classified as an Electric Welded Pipe, and the strength was specified to meet Grade B requirements. This edition will be referred to as API 5-L, 10^{th} Edition throughout the report and the accompanying tables.

2.3.1.2 The currently applicable edition of the specification is ANSI/API 5L, 44^{th} Edition, Effective October 1, 2007, with Errata dated January 2009, Addendum 1 dated February 2009, Addendum 2 dated April 2010, and Addendum 3 dated July 2011. The requirements for PSL 1 Welded Pipe, Grade X42 will be used for comparison, with the exception of the Charpy V-Notch (CVN) impact tests. For the CVN impact tests, there are no requirements for PSL 1 Welded Pipe, so the requirements for PSL 2 Welded Pipe will be referenced instead. This edition of the specification will be referred to as API 5L, 44^{th} Edition throughout the report and accompanying tables.

2.4 Items Received for Testing

2.4.1 On April 16, 2013 at approximately 1:50 pm CST, HurstLab received two (2) cut sections of pipe, and various other items from the failure location in Mayflower, Arkansas, which had been transported on a flatbed trailer. The two (2) sections of pipe were each wrapped in protective plastic with the open ends of the pipe sealed, and with the entire surface covered with plastic padding to protect from damage during loading/unloading and transportation. A 55 gallon steel drum, containing the coating that was removed in the field where the pipe was sectioned transversely, as well as a small bag containing possible calcareous deposits, were also received. The two (2) sections of pipe are described below in the same manner they are referenced throughout the report.

1) 33' 11-1/2" Long Fractured Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it failed in service in Mayflower, Arkansas.

2) 19' 10" Long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it failed in service in Mayflower, Arkansas.

The Chain of Custody documents for the sections of pipe, as well as the steel drum of coating material and the possible calcareous deposits as well as the photographs documenting the evidence in the as-received condition are presented in Appendix II of this report.

3.0 METALLURGICAL EXAMINATION, TESTING AND ANALYSIS

3.1 Visual and Macroscopic Observations

3.1.1 A 49' 9-1/2" long section of the Pegasus Pipeline, which fractured over a length of 22' along the ERW seam and 3" into the base metal at Milepost 314.77 in Mayflower, Arkansas, as shown in Photographs No. 1 through No. 3, was removed from the ground by sectioning through three (3) locations of the pipeline following removal of the coating at those areas on the O.D. surface. The pipeline was transversely sectioned 3' upstream from the north girth weld through the adjoining intact pipe, 33' 11-1/2" from the north cut end, and 1' downstream from the south girth weld through the adjoining intact pipe.

3.1.2 The sections of pipe were received at HurstLab on April 16, 2013. The protective plastic, wrapping, and end plugs from both 33' 11-1/2" and 19' 10" long sections of the pipeline were carefully removed following receipt for examination and documentation of the evidence in the as-received condition, and to allow examination of the general condition of the pipe sections, such as the fracture, ERW seam and girth weld conditions, coating condition, evidence of any corrosion, mechanical damage, etc. Photographs No. 4 through No. 7 display the pipe sections in the as-received condition, and following removal of the plastic and wrapping.

Examination of the 33' 11-1/2" long section of the pipe revealed a 22' long fracture along the ERW weld seam, which traversed diagonally, approximately 3" in length, into the base metal near the south end of the fracture. The fracture faces had been coated with a protective white grease in the field following the pipeline rupture to help preserve the fracture faces for subsequent analysis. All four (4) cut ends of the pipe sections were marked in the field denoting the location of the ERW seam, the relative position in ground, direction of the crude oil flow, station number and field cut match line in each section of the pipe. Photographs No. 8 and No. 9 display the as-received condition of the pipe and field markings on the pipe sections.

3.2 As-Received Condition of the Pipe and Coating

3.2.1 Following unloading of the pipe from the transport truck and unwrapping of the protective material, the pipe was closely inspected to ascertain and document the as-received condition of the pipe and the coating. The 33' 11-1/2" long section of pipe contained a circumferential girth weld at the north end, and an approximately 3' long section of the adjoining intact pipe. The fracture, which followed the ERW seam at the 12:00 o’clock position of the pipe, extended 22' 3" in length, with one fracture tip terminating in the north girth weld and the other in the base metal adjacent to the ERW seam. The maximum separation of the open crack was approximately 1-3/8" wide near the center of the crack, 12' from the north girth weld.

3.2.2 Examination of the coating showed a number of areas where the coating was damaged or split adjacent to the ERW seam. The maximum width and depth of the various splits in the coating on the O.D. surface of the pipe adjacent to the ERW seam, between the 10:30 and 1:30 o’clock positions, were measured and photographically documented. Photographs No. 10 through No. 23 show the condition of the coating from 3' north of the north girth weld, referenced to as -3' from the north girth weld, to the girth weld at 0', and all the way to 50' 9-1/2" south of the north girth weld. As previously mentioned, the coating had been removed in the field from the areas where the pipe had been transversely sectioned.

Distance from North Girth Weld		Coating Split Maximum Width	Coating Split Maximum Depth	Notes
-3'	0'	1"	*	Some coating had been removed during sectioning in the field
0'	4'	2"	0.10"	
4'	8'	0.5"	0.14"	Longitudinal fracture or rupture of the pipe extended from the north girth weld at 0' to 22'
8'	12'	0.5"	*	
12'	16'	*	0.07"	
16'	20'	0.25"	0.09"	
20'	24'	0.5"	0.10"	
24'	28'	1.5"	0.10"	
28'	30' 11-1/2"	1"	0.05"	Some coating had been removed during sectioning in the field
30' 11-1/2"	35'	1"	0.15"	
35'	39'	1"	0.10"	
39'	43'	0.75"	0.11"	
43'	47'	0.5"	0.11"	
47'	50' 9-1/2"	1"	*	Some coating had been removed during sectioning in the field

*Not measurable at location.

The total thickness of the coating was estimated to be approximately 0.15" based on relatively intact areas of the coating, so some of the splits in the coating noted in the table above had likely penetrated to the base metal of the pipe.

In addition to the splits noted above, the coating at the bottom, or 6 o'clock position of the pipe was wrinkled, with the coating appearing to have sagged downward during the years the pipe lay buried. Although the coating did not appear stretched over the top and sides of the pipe, excess coating was folded over at the bottom of the pipe. Several places had small areas of coating missing, although it is not known at what point the coating loss had occurred during service. Additional photographs of the pipe and coating in the as-received condition are displayed in Photographs No. 24 through No. 64.

3.3 Coating Removal Process

A procedure for a safe removal of the coating from the O.D. surface of the pipe was developed and approved by EMPCo and PHSMA, and is listed in Section A4 of the Test Protocol in Appendix I.

The coating on the O.D. surface of the pipe was carefully removed on April 22, 2013 by Watkins Construction Company, LLC. (Watkins), a vendor contracted directly with EMPCo. Prior to proceeding, the contracted workers were briefed by HurstLab personnel as to the importance of preserving the fracture surface and integrity of the pipe; HurstLab personnel supervised the removal of the coating to ensure the safe removal of the coating.

The coating on both pipe sections was first wet down with water, and each pipe section was then tightly wrapped in plastic wrap to securely collect all the coating. To remove the coating it was first cracked by tapping, and was then gently peeled off. First striking the coating with a resin hammer was tried; when the resin hammer did not crack the coating a steel mallet was used. The steel mallet was tapped against the coating, cracking the coating but not damaging the pipe underneath. The pipe sections were then cleaned using mineral spirits. Extreme care was taken to prevent any damage to the pipe or the fracture surface that could have affected the metallurgical investigation.

All of the coating removed from the pipe sections at HurstLab, as well as the steel drum containing the coating that was removed in the field by EMPCo personnel, was collected and retained at EMPCo's facility in Corsicana, Texas. Appendix III shows several representative photographs of the coating removal process and contains the document signed by the employees of Watkins who removed the coating following the briefing by HurstLab personnel.

3.4 Condition of the Pipe Following Coating Removal

3.4.1 Following removal of the O.D. coating in accordance with the specified guidelines, the pipe sections were re-examined to ascertain and photographically document the conditions of the pipe. The bottom of the pipe sections between approximately 4 and 8 o'clock, at the locations where the coating had wrinkled and sagged, was covered with a reddish-orange substance, likely a mixture of the surrounding native sandy soil that the pipe had been buried in and various corrosion products resulting from contact between the pipeline and moisture. Some corrosion pitting was visible within this area, as well as at various locations along the O.D. surface where the coating had previously split and allowed moisture to contact the surface of the pipe. No preferential or knife-like corrosion was present along the ERW seam at 12 o'clock.

3.4.2 The depth of the corrosion pitting at the various locations around the O.D. surface of the fractured pipe section was measured using a certified and calibrated caliper, and the results are summarized in the following table.

Distance from North Girth Weld	Circumferential Location (o'clock position)	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
-3' to 0'	All	No Corrosion Pitting Visible		
0' to 4'	7:30 to 10:00	0.006"	0.017"	0.029"
4' to 8'	1:30 to 3:00	0.008"	0.013"	0.026"
	6:45 to 10:00	0.002"	0.013"	0.037"
8' to 12'	3:45 to 5:00	0.004"	0.011"	0.022"
	7:30 to 11:15	0.002"	0.011"	0.026"
12' to 16'	3:00 to 5:00	0.003"	0.013"	0.033"
	6:30 to 10:00	0.003"	0.017"	0.031"
16' to 20'	2:45 to 5:15	0.005"	0.015"	0.031"
	7:00 to 10:00	0.006"	0.012"	0.021
20' to 24'	2:45 to 5:00	0.004"	0.020"	0.033
	7:15 to 10:00	0.005"	0.010"	0.021
24' to 28'	All	No Corrosion Pitting Visible		
28' to 31'	All	No Corrosion Pitting Visible		

As shown, all of the corrosion pitting occurred between the 1:30 and 11:15 o'clock positions on the fractured section of pipeline; no pitting corrosion was observed at the 12 o'clock position where the ERW seam was positioned in the pipe. The average pitting depth over the entire section of the pipe was determined to be 0.014", and the maximum depth at any location was 0.037", which are approximately 4.5% and 12%, respectively, of the total wall thickness of the pipe. No corrosion pitting was present at either cut end of the fractured pipe section. Photographs showing the corrosion pitting on the east and west sides of the pipe following removal of the coating are displayed in Photographs No. 65 through No. 82.

3.4.3 The I.D. surface of both pipe sections was examined using oblique lighting and pivoting mirrors and magnifying glasses prior to sectioning. No corrosion pitting was visible on the I.D. surface of either the fractured or intact sections of pipe. However some shallow bottomed depressions were observed at random locations.

Following sectioning of the 33' 11-1/2" long and the 19' 10" long pipe lengths, the I.D. surfaces at several areas were more closely examined. Multiple shallow depressions, including those noted above, were visible around the entire circumference of the I.D. surface. The depressions were very smooth in appearance and contained no visible corrosion products, suggestive of mechanical deformation as opposed to corrosion pitting. No evidence of any significant corrosion pits was visible on the I.D. surface. Photographs No. 83 and No. 84 show representative areas of the I.D. surface.

3.5 Dimensional Measurements

3.5.1 The out-of-roundness at intact locations at either end of the fracture, as well as at the south cut end of the 33' 11-1/2" long fractured section of pipe, was determined as specified in Section 10.2.8.3 of API 5L, 44th Edition. At each of the three (3) locations, four (4) measurements of the I.D. were taken, spanning between 12:00 and 6:00 o'clock, 1:30 and 7:30 o'clock, 3:00 and 9:00 o'clock, and 4:30 and 10:30 o'clock using a certified and calibrated I.D. micrometer. In accordance with the method specified in the aforementioned section of API 5L, 44th Edition, the out-of-roundness at each location was then determined to be the difference between the largest and smallest I.D. measurement. The calculated out-of-roundness at each location is displayed in the following table, along with the API requirements.

Circumferential Location of Measurement (o'clock)		I.D. Measurement Distance from North Girth Weld		
Begins	Ends	-6"	271"	371"
12:00	6:00	19.3652"	19.363"	19.392"
1:30	7:30	19.463"	19.375"	19.457"
3:00	9:00	19.353"	19.390"	19.357"
4:30	10:30	19.350"	19.354"	19.437"
Calculated Out-of-Roundness		0.111"	0.036"	0.100"
API 5L, 44th Edition, Table 10, Pipe Except End Out-of-Roundness tolerance for D = 20"				0.400"

As shown, at each of the locations tested the calculated out-of-roundness was determined to be within the allowable tolerance specified in API 5L, 44th Edition, Table 10, for welded pipe with a nominal O.D. between 6.625" and 24". The results of the multiple I.D. measurements and the out-of-roundness calculations are recorded in Table 1.

3.5.2 Wall thickness measurements of the failed pipe were made at 2" intervals along the fracture adjacent to each mating fracture surface, using a certified and calibrated micrometer. The measurements were taken beginning at a location 40" south of the north girth weld and terminating at the crack tip, located 267", or 22' 3", from the north girth weld. Although the other crack tip was located at the north girth weld, the distance between the mating fracture surfaces was too small to allow for accurate wall thickness measurements at or directly adjacent to the north girth weld.

The smallest wall thickness was measured to be 0.310" and the largest was 0.321". The average wall thickness was calculated to be 0.315", while the nominal specified wall thickness for the 20" O.D. pipe was 0.312". The complete results of the wall thickness measurements taken on either side of the crack using a certified and calibrated digital micrometer are recorded in Table 2.

3.5.3 The wall thickness of the fractured pipe was measured at numerous locations both at and away from the fracture by SGS-PfiNDE, Inc. (PfiNDE), an approved third party vendor using the non-destructive ultrasonic test method.

3.5.3.1 A grid or 'map' of ultrasonic wall thickness measurements, covering from 12" upstream to 12" downstream of the fracture and around the entire 360° circumference of the pipe, were taken at 2" intervals over a total pipe length of 24.67'. The wall thickness was determined to range between 0.288" and 0.316" along the evaluated length. No internal corrosion areas were noted, although a linear inclusion in the mid-wall area of the pipe was noted on the CMAPPs (AUT) inspection. The complete results of the ultrasonic wall thickness measurements of the fractured pipe are recorded in Appendix IV.

3.6 Residual Stresses

3.6.1 As the pipe containing the fracture was sectioned for fractographic examination, a significant amount of displacement of the sectioned portion of pipe was observed near the crack tip adjacent to the north girth weld, as shown in Photograph No. 85, indicating that the pipe had been under a considerable amount of constraint since it was manufactured, placing the ERW seam under sustained tension forces, which contributed to the increase in stresses at the ERW seam joint. The separation of the fracture faces confirms elastic spring back in the circumferential direction, indicating the presence of circumferential residue stresses likely associated with the original forming and ERW seam welding of the pipe. However, the extent to which these residual stresses may have contributed to the initiation of the hook cracks or the final fracture is unknown at this time.

3.7 Fractographic Examination

3.7.1 The mating fracture faces of the entire 22' 3" long fracture were visually examined using oblique lighting prior to removal of the coal-tar coating, but following removal of the protective grease with mineral spirits, acetone, and a nylon brush. A thorough, careful examination of both mating fracture faces revealed fine chevrons or radial lines emanating from the fracture zone at a distance between 19' 10" and 21' 6-1/4" from the north girth weld, indicating that the final fracture, which resulted in the leakage of the crude oil, originated from this zone. Visual examination of the mating fracture faces from the distance between 1/4" and 26" south of the north girth weld revealed evidence of upturned grain flow lines or bands, and/or inclusions near the outer wall. However, there was no evidence of any chevron marks pointing to this fracture zone, indicating that the fracture did not initiate from this zone, but rather propagated through the surface imperfections. Photograph No. 86 displays overall and close-up views of the fracture origin and the tip areas, as well as field markings on the pipe.

The fracture zones from a distance between 19' 10" and 20' from the north girth weld was further examined to characterize the fracture morphologies. Fractographic examination revealed flat, highly oxidized, fracture zones predominantly in the upper half (adjacent to the O.D. surface) of the fracture surface along the ERW seam, which are characteristic of hook cracks. Examination further revealed radial lines emanating from the tips of the hook cracks, indicating that the final fracture, which occurred during service and resulted in the leakage of the crude oil, originated from the tips of hook cracks that had reduced the effective cross-sectional area of the wall at the ERW seam location. A hook crack is defined in API Bulletin 5TL as "Metal separations resulting from imperfections at the edge of the plate of skelp, parallel to the surface, which turn toward the inside diameter or outside diameter pipe surface when edges are upset during welding." Photograph No. 87 displays the final fracture initiation sites with insert photographs, revealing the hook cracks, final fracture zones, and the direction of the fracture propagation. The secondary fracture zone, found from a distance between 1/4" and 26" from the north girth weld, contained ERW seam manufacturing imperfections in the upset/HAZ area that had most likely cracked during the final rupture, and is displayed in Photographs No. 88 through No. 94.

3.7.2 A section of the pipe containing the hook cracks, which measured approximately 3-1/2" to 4" in width and approximately 40" in length, was cut and removed from the pipe for closer examination of the O.D. and I.D.

surfaces, and characterization of the fracture morphology. Photographs No. 95 and No. 96 display the cut sections. Close-up examination of the fracture face from a distance between 18' 10" and 19' 10-1/4" from the north girth weld revealed fine chevrons pointing to the hook cracks, indicating that the final fracture originated from the hook cracks and rapidly propagated upstream toward the north girth weld through the HAZ of the ERW seam. Photographs No. 97 through No. 100 display the evidence of chevrons pointing to the hook cracks. Further examination of the fracture face from a distance between 19' 10" and 20' 8" from the north girth weld revealed continuation of the hook cracks and transitioning of the radial lines into vertical lines, indicating the primary fracture origins to be between 20' 2-3/8" and 20' 7-3/8", as displayed in Photographs No. 101 through No. 103. Examination of the remaining fracture surface of the selected fracture face revealed continuation of the hook cracks with intermittent termination and continuation up to a location approximately 20' 11" from the north girth weld, and occasional hook cracks near the I.D. surface of the pipe with chevrons pointing in the opposite direction, indicating that the remaining final fracture propagated toward the south end and terminated in the base metal, as displayed in Photographs No. 104 through No. 110.

In addition to the total depth of the hook cracks, the length and depth below the O.D. surface of various fracture zones on the fracture surface were measured as per the client's request. The darker smooth areas on the fracture surface, all beginning at the O.D. surface, indicated areas of the hook cracks that contained a tightly adhered layer of oxide scale from exposure to moisture; the length and maximum depth of each of these areas was measured. Several axial ridges were also visible on the fracture surface within the hook cracks, formed most likely as a result of the microstructural conditions of the upturned banded grain structure within the ERW seam upset and primary HAZ and potential microcracks through which the fracture occurred. The following table records the measurements, along with the distance from the north girth weld and reference to the photographs showing the various fractographic features.

Fracture Zone Number	Photograph Number	Distance from North Girth Weld	Feature Appearance	Total Length	Depth Below O.D. Surface
1	101	20' 3/8" to 20' 7/8"	Darker Smooth Area	1/2"	0.125"
2	102	20' 2-1/8" to 20' 2-5/8"	Darker Smooth Area	1/2"	0.063"
3	102 - 103	20' 3" to 20' 4-3/8"	Darker Smooth Area	1-3/8"	0.085"
4	102	20' 3" to 20' 3-3/4"	Ridge	3/4"	0.061"
5	102 - 103	20' 3-7/8" to 20' 4-1/8"	Ridge	1/4"	0.058"
6	103	20' 4-5/8" to 20' 7-5/8"	Darker Smooth Area	3"	0.150"
7	103	20' 4-5/8" to 20' 6-3/8"	Ridge	1-3/4"	0.113"
8	104	20' 7-7/8" to 20' 8-1/8"	Darker Smooth Area	1/4"	0.046"
9	104	20' 8-5/8" to 20' 9"	Darker Smooth Area	3/8"	0.063"
10	104 - 105	20' 9-1/8" to 20' 11-1/4"	Darker Smooth Area	2-1/8"	0.048"
11	105 - 106	21' 1/8" to 21' 1-1/2"	Darker Rough Area	1-3/8"	0.062"
12	106 - 107	21' 3" to 21' 4-3/8"	Darker Rough Area	1-3/8"	0.031"
13	107	21' 5" to 21' 5-1/2"	Darker Rough Area	1/2"	0.042"
14	107	21' 5-1/2" to 21' 5-7/8"	Darker Smooth Area	3/8"	0.020"

3.7.3 An approximately 5-1/2" long section of the fracture surface containing the primary final fracture origins and some of the hook cracks between a distance of 20' 2-1/2" and 20' 8" from the north girth weld was removed, electrolytically descaled, cleaned using alkaline Endox® 214 solution, and examined at low magnifications to ascertain the general condition of the pipe surface at the O.D. and I.D. surfaces along the ERW seam near the fracture origins. The mating fractured surface was not cleaned to preserve the sample for the later evaluation of the condition of the scale or oxidation that was present on the fractured face.

Close-up examination of the cleaned fracture face containing hook cracks and the final fracture origins revealed that one of the final fracture origins was at a location where the outer coal-tar coating had split diagonally during service. Some of the coal-tar had melted onto the fracture surface. The examination also revealed localized melting of the pipe metal caused by the copper electrode contacts that were apparently originally used to weld the skelp to form the ERW pipe. Photographs No. 111 through No. 116 display the O.D. surface condition of the pipe near the fracture origins.

Close-up examination of the fracture face between a distance of 20' 2-1/2" and 20' 8" from the north girth weld revealed highly oxidized hook cracks and the final fracture originating from the hook cracks, which were present to a maximum depth of 0.150". Photographs No. 117 through No. 122 display the hook cracks and the origins from where the final fracture initiated and propagated north toward the north girth weld along the ERW seam and south into the base metal south of the fracture origins.

3.7.4 The hook cracks and the final fracture zones across the entire fracture face from the O.D. to the I.D. of the pipe at two (2) of the several fracture origins, located at 20' 5-5/16" and 20' 6-3/4" from the north girth weld, as shown in Photographs No. 117 through No. 122, were examined at higher magnifications using a Scanning Electron Microscope (SEM) to further characterize the fracture morphologies. The SEM examination of the hook cracks revealed fractures through the multiple planes across the weld upset, HAZ, and/or fusion line of the ERW seam, which were covered with tightly adhered scale or oxidation products obscuring the fracture morphology. However, the fractures through multiple planes in the weld upset, HAZ, and/or fusion line suggest that the cracks propagated through the path of least resistance. There was some evidence of what appeared to be intergranular fracture in an extremely small area of the hook crack, which can be attributed to the prior grain structure of the material. The final fracture zone revealed essentially cleavage to quasi-cleavage fracture, indicative of brittle instantaneous failure. The fracture through the weld flash near the I.D. surface revealed evidence of ductile fracture. Photographs No. 123 through No. 150 document the fracture morphologies at the fracture origin locations.

3.8 Crack Measurements

3.8.1 Fractographic examination of the fracture face between 19' 10" and 22' revealed the presence of the hook cracks along the multiple planes of the ERW seam between a distance of 19' 10-1/8" and 21' 9-1/2"; however, the hook cracks were predominantly located between 19' 10-1/8" and 20' 11-3/8", and 21' 2" and 21' 9-1/4", as measured from the north girth weld. The maximum depth of the hook cracks, from where the final fracture initiated during service and lead to the rupture of the pipeline, was 0.150"; however, the depth of the hook cracks varied between 0.016" and 0.150", as recorded in Table 3.

3.8.2 The mating fracture faces in the crack origins area from where the final fracture had initiated between a distance of 20' 2-1/2" and 20' 8" were reconstructed and sectioned transversely across the fractured ERW seam, more specifically at distances of 20' 3-3/4", 20' 4-7/8", and 20' 5-1/2" from the north of the girth weld, and were prepared for metallographic examination as well as the crack width measurements. Additional cross-sections were also removed through the fractured ERW seam from a distance of 20' 6-13/16" and intact seam from a distance of 35' 8-1/2" and prepared for metallographic examination.

3.8.3 The maximum width and depth of the hook cracks were measured at several locations and were found to be 0.0038" and 0.150", respectively. It should be noted here that the hook crack width measurements were made following reconstruction of the two (2) mating fracture faces and, therefore, the values shall be considered as approximates only. Table 4 records the hook cracks width measurements.

3.9 Metallographic Evaluation

3.9.1 Microstructural examination of the cross-sections removed transversely through the ERW seam at a distance of 20' 4-7/8" and 20' 6-13/16" from the north girth weld and prepared for metallographic examination was performed to characterize the microstructural conditions of the ERW seam at the fracture origin locations. Microstructural examination revealed hook cracks through the ERW upset/HAZ along the realigned inclusions and upturned bands of extremely brittle untempered martensite.

Both cross-sections removed through the final fracture origins and prepared for metallographic examination confirmed the presence of hook cracks through the excessive amount of manganese sulfide inclusions and bands which were essentially parallel to the ERW fusion line, an undesirable condition that was apparently created during the skelp forming and ERW processes. The microstructure of the upturned bands consisted of very brittle, hard untempered martensite, while the ERW upset/HAZ area consisted of a mixed-microstructure with grain boundary ferrite, unresolved bainite, and some untempered martensite, which is undesirable since this microstructure possesses extremely low ductility. The secondary HAZ and the base metal consisted of grain boundary ferrite and pearlite.

Microstructural examination also revealed evidence of localized melting and cracking to a shallow depth at the electrode contact areas at the O.D. locations parallel to the weld seam. Photographs No. 151 through No. 202 document the microstructural condition of the ERW seam at the locations of the hook cracks from where the final fracture had initiated and predominantly propagated upstream toward the north girth weld.

3.9.2 A cross-section was removed transversely through the intact portion of the ERW seam of the 49' 9-1/2" section of the pipeline at a distance of 35' 8-1/2" from the north girth weld and prepared for metallographic examination to characterize the microstructural condition of the ERW seam.

The microstructural examination revealed excessive amounts of predominantly manganese sulfide stringers and some oxide inclusions, several of them aligned parallel to the fusion line in the upset area of the ERW seam, which is a highly undesirable condition and can lead to the formation of hook cracks. The microstructural examination of the cross-section following etching in a 2% Nital solution revealed the presence of some upturned bands, however not as severe as those found in the fractured seam. The microstructure of the upturned bands consisted of brittle untempered martensite, while the upset/HAZ away from the bands consisted of mix-microstructure of grain boundary ferrite, bainite, and some untempered martensite. Photographs No. 203 through No. 220 document the microstructural condition of the intact ERW seam.

3.9.3 Longitudinal cross-sections were removed through the corrosion pitting at representative areas on the O.D. surface and through the shallow indentations on the I.D. surface, and were metallographically prepared and etched in a solution of 2% Nital. On the O.D. surface multiple pits filled with oxides and corrosion products were visible, extending to a maximum depth of 0.008" on the metallographically prepared cross-sections. Following etching, the non-uniform pits were confirmed to be the result of material loss due to corrosion, with no evidence of grain deformation or mechanical damage. As previously noted, all of the corrosion pitting was observed between the 1:30 and 11:15 o'clock positions on the fractured section of pipe, and no pitting corrosion was observed at the 12:00 o'clock position where the ERW seam was positioned in the pipe. The corrosion observed on the O.D. surface did not contribute to the pipeline failure.

Examination of the I.D. surfaces on the metallographically prepared cross-sections revealed that the shallow depressions were smooth indentations, between 0.137" and 0.189" wide and up to 0.007" deep. The I.D. surface and the surfaces of the indentations were smooth, with no visible oxide scale, and in the etched condition some grain deformation was visible at the edges of the indentations, indicating mechanical damage. However, the thickness of the microstructural band containing partial decarburization on the I.D. surface remained constant, indicating that the impressions occurred most likely during the hot-rolling of the steel or manufacturing of the pipe and not during service. The I.D. surface indentations did not contribute to the pipeline failure. Photographs No. 221 through No. 226 display representative areas of the O.D. and I.D. surfaces on the metallographically prepared longitudinal cross-sections in both the as-polished condition and following etching in a solution of 2% Nital.

3.10 Microhardness Surveys

3.10.1 Vickers microhardness surveys were performed on the metallographically prepared cross-sections at both the representative fractured and intact locations of the ERW seam on the pipe sections in accordance with the test method specified in ASTM E384-11$^{\epsilon 1}$. The Vickers microhardness values were converted to equivalent Rockwell B or C scale values based on the conversions provided in ASTM E140-07, Tables 1 and 2. It should be emphasized that the hardness equivalents are approximates based on equations developed from empirical data, and are typically higher than the results obtained by testing using the larger Rockwell indenter and much higher load forces.

3.10.2 Vickers microhardness surveys were performed on the metallographically prepared cross-sections removed from representative fractured areas of the ERW seam at 20' 4-7/8" and 20' 6-13/16" from the north girth weld. Each cross-section was evaluated along the fracture surface, including along the hook crack(s), the hardened martensitic upturned grains, and the final fracture zone, as well as in the ERW seam at the fusion line, the HAZ and the base metal. The results of the Knoop microhardness surveys at fractured locations of the pipe are summarized in the following table.

Cross-section Location (from North Girth Weld)	Average Hardness, Rockwell Equivalent					
			At Fracture Surface			
	Base Metal	Heat-Affected Zone	Hook Crack	Hardened Upturned Grains	Final Fracture	ERW Fusion Line
20' 4-7/8"	96 HRB	100 HRB	29 HRC	52 HRC	28 HRC	42 HRC
20' 6-13/16"	100 HRB	21 HRC	29 HRC	49 HRC	29 HRC	32 HRC

As shown, the hardness varied extensively along the fracture surface of the hook crack(s) within the upturned grains. The hardened, martensitic microstructure was 20 to 23 Rockwell C hardness points higher than the adjacent microstructure within the upturned grains and along the fusion line in the ERW seam. The hardness decreased the farther away from the ERW seam, resulting in approximately a 30 Rockwell C hardness point difference between the ERW seam and the softer base metal. The large difference in hardness is undesirable and results in increased internal stresses, which can contribute to crack initiation and propagation. The complete results of the Vickers microhardness surveys, including micrographs showing the locations of each indentation on the metallographically prepared cross-sections removed through the crack are displayed in Table 5 and Table 6.

3.10.3 A Vickers microhardness survey was also performed on the metallographically prepared cross-section that was removed through the ERW seam at a representative intact area approximately 35' 8-1/2" from the north girth weld for comparison with the data from the fractured location. The results of the Vickers microhardness survey of the intact area are displayed in the following table.

Cross-section Location (from North Girth Weld	Hardness, Rockwell Equivalent			
	Base Metal	Heat-Affected Zone	Upturned Grain Flow Lines	ERW Fusion Line
35' 8-1/2"	100 HRB average	99 HRB average	Varied between 21 HRC and 54 HRC	Varied between 23 HRC and 54 HRC

As shown, the cross-section removed from an intact area of the pipe also contained a hardened martensitic microstructure within the upturned grain flow pattern of the ERW seam at the O.D. surface. The fusion line, HAZ, and base metal hardnesses of the intact cross-section were similar to those areas on the fractured cross-sections, including the large variation between the ERW seam and the base metal of the pipe. The complete results of the Vickers microhardness survey, including a micrograph of the metallographically prepared cross-section removed from the ERW seam in an intact area, are displayed in Table 7.

3.11 Tensile Tests

3.11.1 In order to determine the ultimate tensile stress, yield stress at a 0.5% offset, and percent elongation of the pipe, multiple tensile test specimen blanks were removed through the ERW seam, as well as in both the transverse and longitudinal directions away from the seam, on the intact 19' 10" long section of pipe as shown in Appendix V. All of the test specimens were machined to have a 2" long gauge length, a 1-1/2" wide reduced section, and represented essentially the entire wall thickness, with only slight sanding to remove minor surface imperfections or, as noted, the weld flash.

3.11.2 Six (6) transverse tensile test specimen blanks were removed through the ERW seam and were then flattened as specified in both the 10th Edition and the 44th Edition of API 5L. The tensile test specimens were then machined and tested in accordance with ASTM A370-12a and the applicable sections of each edition of the API 5L specification. The results of the transverse tensile tests through the ERW seam, along with the tensile requirements from both the 10th Edition of API 5-L that was in effect at the time the pipe was manufactured and the current API 5L, 44th Edition are shown in the following table.

Sample Identification	Ultimate Stress (psi)	Yield Stress (psi)	Elongation (%)	Fracture Location
Transverse, Through ERW Seam, Weld Flash Included, Sample 1	101,000	77,000	4	HAZ
Transverse, Through ERW Seam, Weld Flash Included, Sample 2	93,500	79,000	5	HAZ
Transverse, Through ERW Seam, Weld Flash Included, Sample 3	102,000	84,000	23	Base Metal
Transverse, Through ERW Seam, Weld Flash Removed, Sample 1	85,500	73,000	3	HAZ
Transverse, Through ERW Seam, Weld Flash Removed, Sample 2	85,500	75,000	3	HAZ
Transverse, Through ERW Seam, Weld Flash Removed, Sample 3	92,500	77,000	5	HAZ
API 5-L, 10th Edition, Electric Welded Pipe, Open Hearth Steel, Grade B	60,000 minimum	None Specified	None Specified	Not Applicable
API 5L, 44th Edition, PSL 1, Welded Pipe, Grade X42	60,200 minimum	None Specified	None Specified	Not Applicable

As shown, all of the tensile test specimens, regardless of whether the specimens contained the weld flash, met the minimum ultimate stress requirements specified in both API 5-L, 10th Edition and API 5L, 44th Edition. The complete results of the transverse tensile tests through the ERW seam are recorded in Table 8.

3.11.3 Multiple base metal transverse tensile test specimen blanks were removed from the pipe, at locations 90° from the ERW seam and 180° from the ERW seam, and were flattened prior to machining. Longitudinal base metal tensile test specimen blanks were also removed from the pipe at a location 90° from the ERW seam. All of the tensile test blanks were machined and tested in accordance with ASTM A370-12a and the applicable sections of sections of each edition of API 5L. The results of both the transverse and longitudinal base metal tensile tests, along with the tensile requirements from both the 10th Edition of API 5-L that was in effect at the time the pipe was manufactured and the current API 5L, 44th Edition are shown in the following table.

Sample Identification	Ultimate Stress (psi)	Yield Stress (psi)	Elongation (%)
Transverse, 90° from ERW Seam, Sample 1	87,000	59,000	30
Transverse, 90° from ERW Seam, Sample 2	86,500	59,000	31
Transverse, 90° from ERW Seam, Sample 3	89,000	62,000	28
Transverse, 180° from ERW Seam, Sample 1	87,000	63,000	28
Transverse, 180° from ERW Seam, Sample 2	85,500	60,000	28
Transverse, 180° from ERW Seam, Sample 3	87,500	64,000	28
Longitudinal, 90° from ERW Seam, Sample 1	89,000	64,500	31
Longitudinal, 90° from ERW Seam, Sample 2	90,000	66,500	31
Longitudinal, 90° from ERW Seam, Sample 3	90,500	68,500	31
API 5-L, 10th Edition, Electric Welded Pipe, Open Hearth Steel, Grade B	60,000 minimum	35,000 minimum	Unknown[1]
API 5L, 44th Edition, PSL1, Welded Pipe, Grade X42	60,200 minimum	42,100 minimum	27% minimum

[1]The required minimum elongation specified on the tensile requirements table in the provided paper copy of API 5-L, 10th Edition is illegible.

As shown, all of the base metal tensile test specimens, in both the transverse and longitudinal directions, met the requirements specified in both API 5-L, 10th Edition and API 5L, 44th Edition. Although the measured yield stress typically exceeded the minimum ultimate stress requirement, it should be noted that there were not any maximum strength requirements. The complete results of the base metal transverse and longitudinal tensile tests are recorded in Tables 9 and 10.

3.11.4 Sub-sized round, non-flattened transverse tensile test specimen blanks were removed through the ERW seam, 90° from the ERW seam, and 180° from the ERW seam on the intact section of pipe, and were machined and tested in accordance with the applicable sections of API 5L and ASTM A370-12a. The results of the non-flattened transverse tensile tests are summarized in the following tables.

Sample Identification	Ultimate Stress (psi)	Yield Stress (psi)	Elongation (%)
Transverse, Through ERW Seam, Weld Flash Removed, Non-flattened	99,600	65,100	21
API 5-L, 10th Edition, Electric Welded Pipe, Open Hearth Steel, Grade B	60,000 minimum	None Specified	None Specified
API 5L, 44th Edition, PSL1, Welded Pipe, Grade X42	60,200 minimum	None Specified	None Specified

Sample Identification	Ultimate Stress (psi)	Yield Stress (psi)	Elongation (%)
Transverse, 90° from ERW Seam, None-flattened	86,100	56,700	27
Transverse, 180° from ERW Seam, None-flattened	83,600	57,900	22
API 5-L, 10th Edition, Electric Welded Pipe, Open Hearth Steel, Grade B	60,000 minimum	35,000 minimum	Unknown[1]
API 5L, 44th Edition, PSL1, Welded Pipe, Grade X42	60,200 minimum	42,100 minimum	27% minimum

[1]The required minimum elongation specified on the tensile requirements table in the provided paper copy of API 5-L, 10th Edition is illegible.

As shown, the sub-sized, non-flattened transverse tensile test specimens met the requirements specified in both API 5-L, 10th Edition and API 5L, 44th Edition. The complete results of the sub-sized, non-flattened transverse tensile tests are recorded in Table 11.

3.12 Charpy V-Notch Impact Tests

3.12.1 Test blanks for multiple sets of transverse Charpy V-Notch (CVN) impact test specimens were removed from the intact 19' 10" long section of pipe as shown in Appendix V. Sets of half-sized 10 mm x 5 mm test specimens were machined per Section 9.8 of API 5L, 44th Edition and

ASTM A370-12a and were notched in the fusion line of the ERW seam, the primary HAZ of the ERW approximately 1 mm from the fusion line, and the base metal. Then for each notch location, one (1) set of three (3) specimens was tested per ASTM A370-12a at the selected test temperatures of plus 32°F, plus 65°F, plus 80°F, and plus 95°F. Base metal specimens were also tested at additional temperatures.

3.12.2 The results of the CVN impact tests for each location and each test temperature are recorded in the following tables.

V-Notch Location: ERW Fusion Line				
Specimen Number	Test Temperature	Impact Value (ft-lbf)	Lateral Expansion (mils)	Percent Shear (%)
1		3	0	0
2	Plus 95°F	2	1	0
3		3	0	0
1		3	0	0
2	Plus 80°F	2	0	0
3		3	1	0
1		3	1	0
2	Plus 65°F	2	0	0
3		3	1	0
1		3	0	0
2	Plus 32°F	3	0	0
3		2	0	0

V-Notch Location: ERW Primary Heat-Affected Zone				
Specimen Number	Test Temperature	Impact Value (ft-lbf)	Lateral Expansion (mils)	Percent Shear (%)
1		3	3	0
2	Plus 95°F	3	4	0
3		4	6	0
1		5	7	0
2	Plus 80°F	4	5	0
3		8	5	0
1		3	2	0
2	Plus 65°F	3	1	0
3		5	2	0
1		4	0	0
2	Plus 32°F	3	0	0
3		4	0	0

V-Notch Location: Base Metal				
Specimen Number	Test Temperature	Impact Value (ft-lbf)	Lateral Expansion (mils)	Percent Shear (%)
1	Plus 95°F	10	16	15
2		10	12	10
3		10	14	10
1	Plus 80°F	9	9	5
2		9	10	5
3		9	13	5
1	Plus 65°F	10	13	5
2		10	14	5
3		10	13	5
1	Plus 32°F	8	8	5
2		9	12	5
3		9	10	5
1	Zero°F	5	1	0
2		4	2	0
1	Minus 32°F	2	0	0

As shown, the impact values at each notch location were essentially the same between plus 32°F and plus 95°F, while the base metal impact values at 0°F were half the values at 32°F and above, and continued to drop with lower temperatures. The fusion line of the ERW seam had the lowest impact values and the base metal, as expected, had the highest values. The lateral expansion and percent shear was essentially zero at the fusion line of the ERW seam, and the lateral expansion was only slightly higher in the HAZ. The base metal had the largest lateral expansion and percent shear values. The results of the CVN impact tests are recorded in Tables 12, 13, and 14.

At the time the pipe was manufactured, no CVN impact tests or requirements were specified in APL 5-L, 10th Edition. Likewise, there are no impact requirements for Type PSL 1 welded pipe in the current 44th Edition of API 5L. The only impact requirements for comparison are that in the 44th Edition of API 5L, for all notch locations on Type PSL 2 welded pipe, Grade ≤X60, half-size transverse test specimens are required to have a 10 ft-lbf minimum average for a set of three test specimens and 8 ft-lbf minimum for a single individual test specimen, when tested at a test temperature of plus 32°F.

3.12.3 The CVN impact test results were then intended to be used to determine the lower shelf energy, upper shelf energy, the ductile-to-brittle transition temperature for the base metal, and if possible, the ERW seam, by plotting the results and developing an S-curve graph. The ductile-to-brittle transition temperature for the ERW fusion line and HAZ can not be determined, because the results of the impact tests at these areas were essentially the same regardless of test temperature. All of the CVN impact test specimens notched in the ERW seam, whether at the fusion line or in the HAZ, failed in an essentially brittle manner, therefore the ductile-to-brittle transition temperature is above 95°F and is outside the scope of this investigation.

However, additional tests at a temperatures below plus 32°F were performed on transverse CVN impact test specimens machined from the base metal because the base metal test specimens did fracture in a more ductile manner. The lower shelf would be considered to be around 2 ft-lbf for the size tested, or 4 ft-lbf for a full-size test specimen.

3.13 Chemical Analyses

3.13.1 An approximately 2" by 2" section was removed away from the ERW seam on the intact 19' 10" long section of pipe, as shown in Appendix V, and the surface was sanded smooth in preparation for determining the chemical composition of the pipe using the Optical Emission Spectroscopic (OES) test method in accordance with ASTM E415-08, with the percent carbon determined by an approved vendor using the combustion method specified in ASTM E1019-11. The results of the chemical composition analysis, as well as the compositional requirements for both the 10th Edition of API 5-L that was in affect at the time the pipe was manufactured and the current API 5L, 44th Edition are shown in the following table.

Element (wt%)	Sample Tested	API 5-L, 10th Edition, Electric Welded Pipe, Open Hearth Steel, Grade B Spec.	API 5L, 44th Edition, PSL 1, Welded Pipe, Grade X42 Specification
Carbon	0.30	0.30 max	0.26 max
Manganese	1.47	0.35 to 1.50	1.30 max
Phosphorus	0.017	0.045 max	0.030 max
Sulfur	0.031	0.06 max	0.030 max
Silicon	<0.01	[1]	[1]
Chromium	<0.01	[1]	0.50 max
Nickel	0.04	[1]	0.50 max
Molybdenum	<0.01	[1]	0.15 max
Copper	0.02	[1]	0.50 max
Aluminum	<0.01	[1]	[1]
Niobium	<0.01	[1]	[2]
Vanadium	<0.01	[1]	[2]
Titanium	<0.01	[1]	[2]
	Base	Base	Base

[1]Analytical range not specified for element.
[2]Sum of Niobium + Vanadium + Tantalum = 0.15% maximum

As shown, the pipe met the chemical composition that was specified in API 5-L, 10th Edition at the time of the pipe manufacture, but does not meet the compositional requirements specified in the current API 5L, 44th Edition for welded pipe. The complete results of the OES chemical analysis of the pipe are recorded in Table 15.

3.13.2 The foreign materials on the fracture surfaces, the O.D. surface, and the tightly adhered, very viscous black coating of the pipe was analyzed using the Energy Dispersive X-ray Spectroscopic (EDS) test method in accordance with ASTM E1508-12a in order to determine the elements present and the relative amounts of each. It should be noted that the fracture surface was protected with white grease prior to shipment to the laboratory, which was removed with the mineral spirit and acetone, and therefore the results of the EDS analysis may not be taken at the face value. Furthermore, it should also be noted that EDS is a semi-quantitative test method, and that the results should be used as comparative or relative values only. It should also be noted that the EDS used was not capable of detecting light elements, those elements with atomic weights less than fluorine.

The following table shows the results of the EDS analysis at three (3) different locations of the fracture surface.

Element (wt%)	Fracture Surface EDS-1	Fracture Surface EDS-2	Fracture Surface EDS-3
Magnesium	3.980	1.925	2.084
Aluminum	3.484	4.776	3.118
Silicon	12.974	12.032	8.578
Sulfur	4.081	2.144	3.006
Chlorine	2.794	2.377	1.864
Potassium	0.975	0.883	0.698
Calcium	1.162	0.874	1.198
Titanium	0.810	0.836	[1]
Manganese	1.603	1.056	1.541
Iron	68.137	73.097	77.912

[1]Element not detected.

As shown, in addition to iron and manganese from the base metal of the pipe, high levels of silicon, aluminum, and magnesium, were detected, most likely due to soil adhering to the fracture surface; similarly the calcium, potassium, and titanium were also likely from the surrounding soil. High levels of the corrosive elements chlorine and sulfur were also detected, although no pitting corrosion had yet occurred on the fracture surfaces. The complete results of the EDS analyses of the material on the fracture surfaces, including line spectra and SEM images of each location, are recorded in Tables 16, 17, and 18.

3.13.3 The chemical composition of the reddish-brown products on the O.D. surface of the pipe was also evaluated using the EDS test method. The results of the EDS analysis are displayed in the following table.

Element (wt%)	Reddish-Brown Product on O.D.
Magnesium	0.417
Aluminum	6.783
Silicon	33.882
Sulfur	0.391
Potassium	1.679
Titanium	0.949
Manganese	0.306
Iron	55.594

As shown, the products on the O.D. surface of the pipe were composed of primarily silicon with aluminum and potassium, in addition to the iron from the base metal of the pipe. The reddish-brown product on the O.D. surface of the pipe was likely soil that had migrated through the splits in the coating of the pipe. Some of the products may also have been from corrosion of the pipe, although it should be stressed that there was no evidence of significant localized or pitting corrosion on the received sections of pipe. The results of the EDS analysis of the products on the O.D. surface of the pipe are recorded in Table 19.

3.13.4 The viscous black bitumen, or coal-tar, coating that was on the O.D. surface of the pipe underneath the layer of fibrous coating was also analyzed using the EDS test method. The results of the test are displayed in the following table.

Element (wt%)	Black Bitumen Coating
Magnesium	4.522
Aluminum	6.942
Silicon	42.773
Sulfur	65.763
Silver	0.000

No specific chemical composition of the coating was available for comparison. Bitumen is a highly viscous mixture composed primarily of highly condensed polycyclic aromatic hydrocarbons that is used as a waterproof coating for buried pipe, among other uses such as paving roads. The results of the EDS analysis of the viscous black coating on the O.D. surface of the pipe are recorded in Table 20.

4.0 CONCLUSION

4.1 Technical Causes of Failure

Based on the inspection, testing, and evaluation performed in accordance with the approved metallurgical test protocol, review of the background information, and technical research, the following is HurstLab's opinion.

The failure of the pipeline at Milepost 314.77 in the Conway to Corsicana section of the Pegasus crude oil pipeline located in Mayflower, Arkansas, which occurred at 2:37 pm CST on March 29, 2013, resulted because of the reduction of the wall thickness in the upset zone of the Electric Resistance Weld (ERW) seam caused by the presence of manufacturing defects, namely the upturned bands of brittle martensite, combined with localized stress concentrations at the tips of the hook cracks, low fracture toughness of the material in the upset/HAZ, excessive residual stresses in the pipe from the initial forming and seam and girth welding processes, and the internal pressure creating hoop stresses.

The hook cracks, with maximum dimensions of 0.0038" in width, 0.150" in depth, and 13-1/4" in length, as measured on the examined section of the fracture surface, were present in the ERW seam prior to the incident for an unknown period of time. The weak upturned fibers or bands of untempered brittle martensite were created during the manufacturing of the pipe. The presence of the tightly adhered scale or oxidation products on the fracture faces of the hook cracks suggests that the hook cracks had been present for an unknown period of time. It is unclear, however, whether the hook cracks occurred immediately after manufacturing or during service. The hook cracks initiated and followed the brittle upturned grain flow lines or bands that were created during the manufacturing of the pipe due to effects of the stresses induced by hydrostatic testing, thermal stresses, residual stresses, and/or pressure cycles.

The hook cracks may not have all occurred simultaneously, as suggested by variation in coloration of the scale or oxides on the fracture surface and the macroscopic features of the fracture. The hook cracks and potential microcracks in the upset/heat-affected zones may have then merged due to stresses during service.

4.2 Failure Scenario

Based on the preceding conclusion, the evidence of the hook cracks through multiple ductile and brittle zones, significant variance in hardness between the various zones of the ERW seam, the tightness and depth of the hook cracks along multiple planes through the upset heat-affected zones, and the extremely low impact toughness and elongation properties across the ERW seam, it is highly probable that some micro-cracking within the upset/heat-affected zones might have occurred immediately following the pipe manufacturing. The micro-cracks then likely would have merged by further cracking through the adjacent areas in the localized upset/HAZ zones during service, forming a continuous hook crack in each of the localized areas to the critical depths, at which point the remaining wall thickness, combined with the localized stress concentration and the residual stresses, could no longer support the internal hoop stresses and resulted in the final failure.

Submitted by,

MMadhani

Mahesh J. Madhani
Chief Metallurgist

Revised on July 9, 2013 to clarify the findings and to make editorial changes.

MP314.77

Photograph No. 1

The photographs provided by EMPCo of the 20" O.D. x 0.312" wall pipe at Milepost 314.77 of the Conway to Corsicana Pegasus crude oil pipeline, which failed on Friday, March 29, 2013 at 2:47 pm CST in Mayflower, Arkansas, display a straight, linear crack at approximately the 12:00 o’clock position.

Photograph No. 2

Photograph No. 3

The photographs display close-up views of the crack tips near the north girth weld in the ERW seam of the pipe and the south end in the base metal, respectively.

Photograph No. 4

Photograph No. 5

The photographs display the fractured section of the pipe in the as-received condition and following removal of the outer protective wrapping material.

Photograph No. 6

The photograph displays the intact section of the pipe in the as-received condition with the outer protective wrapping material.

Photograph No. 7

The photograph displays the intact section of the pipe following removal of the 2^{nd} protective wrapping material.

Photograph No. 8

The photograph displays the fractured pipe section following removal of the 2nd wrapping material, revealing the fracture faces coated with grease to protect from post-incident corrosion.

Photograph No. 9

The photograph displays the intact section of the pipe following removal of the 1st protective wrapping material.

Photograph No. 10

Photograph No. 11

As-received Condition of the Coating			
Circumferential Location	Distance from North Girth Weld	Split Width Maximum	Split Depth Maximum
10:30 o'clock to 1:30 o'clock	-3' to 0'	1"	-
	0' to 4'	2"	0.10"

The photographs display overall top views of the pipe adjacent to the fractured pipe from approximately 3' north of the north girth weld (-3') to the center of the north girth weld (0'), and the fractured pipe from the center of the girth weld to 4' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The fracture in the pipe along the ERW seam terminated at the north girth weld. The fracture was extremely tight at the girth weld but was measured to be approximately 13/16" in width approximately 4' south of the north girth weld. Relatively narrow longitudinal and transverse splits were present in the coating. The coating had been removed from the adjacent intact pipe prior to sectioning approximately 3' north of the north girth weld.

Photograph No. 12

Photograph No. 13

As-received Condition of the Coating			
Circumferential Location	Distance from North Girth Weld	Split Width Maximum	Split Depth Maximum
10:30 o'clock to 1:30 o'clock	4' to 8'	0.5"	0.14"
	8' to 12'	0.5"	-

The photographs display overall top views of the fractured pipe from 4' south to 8' south of the north girth weld, and from 8' south to 12' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. Longitudinal and transverse splitting is present in the coating, and some of the coating is missing on either side of the fracture.

Photograph No. 14

Photograph No. 15

As-received Condition of the Coating			
Circumferential Location	Distance from North Girth Weld	Split Width Maximum	Split Depth Maximum
10:30 o'clock to 1:30 o'clock	12' to 16'	-	0.07"
	16' to 20'	0.25"	0.09"

The photographs display overall top views of the fractured pipe from 12' south to 16' south of the north girth weld, and from 16' south to 20' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. Longitudinal and transverse splitting is present in the coating, and some of the coating is missing on either side of the fracture.

Photograph No. 16

Photograph No. 17

As-received Condition of the Coating			
Circumferential Location	Distance from North Girth Weld	Split Width Maximum	Split Depth Maximum
10:30 o’clock to 1:30 o’clock	20' to 24'	0.5"	0.10"
	24' to 28'	1.5"	0.10"

The photographs display overall top views of the fractured pipe from 20' south to 24' south of the north girth weld, and from 24' south to 28' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. At approximately 22' south of the girth weld, the fracture in the ERW seam turned into the pipe material, progressing several inches prior to terminating. The damaged area of coating near the pipe fracture extended longitudinally past the fracture tip several feet.

Photograph No. 18

Photograph No. 19

As-received Condition of the Coating			
Circumferential Location	Distance from North Girth Weld	Split Width Maximum	Split Depth Maximum
10:30 o'clock to 1:30 o'clock	28' to 31'	1"	0.05"
	31' to 35'	1"	0.15"

The photographs display overall top views of the fractured pipe from 28' south to 31' south of the north girth weld, and from 31' south to 35' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The approximately 49' 9-1/2" long pipe was sectioned in the field transversely approximately 31' south of the north girth weld. The coating was removed in the field approximately 13" in either direction from the transverse cut prior to sectioning.

Photograph No. 20

Photograph No. 21

As-received Condition of the Coating			
Circumferential Location	Distance from North Girth Weld	Split Width Maximum	Split Depth Maximum
10:30 o'clock to 1:30 o'clock	35' to 39'	1"	0.10"
	39' to 43'	0.75"	0.11"

The photographs display overall top views of the fractured pipe from 35' south to 39' south of the north girth weld, and from 39' south to 43' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. Longitudinal splitting is visible on the surface of the coating.

Photograph No. 22

Photograph No. 23

As-received Condition of the Coating			
Circumferential Location	Distance from North Girth Weld	Split Width Maximum	Split Depth Maximum
10:30 o'clock to 1:30 o'clock	43' to 47'	0.5"	0.11"
	47' to 51'	1"	-

The photographs display overall top views of the fractured pipe from 43' south to 47' south of the north girth weld, and from 47' south to 51' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. Longitudinal splitting is visible on the surface of the coating. Some of the coating had been removed from the adjacent area pipe prior to sectioning.

Photograph No. 24

Photograph No. 25

The photographs display overall views of the west side of the pipe from 7:30 to 10:30 o'clock, adjacent to the fractured pipe from approximately 3' north of the girth weld (-3') to the center of the north girth weld (0'), and the fractured pipe from the center of the girth weld to 4' south of the north girth weld (+4'), respectively, in the as-received condition prior to removing the coating. The lower half of the pipe contains disbonded and wrinkled coating.

Photograph No. 26

The photograph displays an overall view of the west side from 7:30 to 10:30 of the fractured pipe from 4' south to 8' south of the north girth weld in the as-received condition prior to removing the coating. The lower half of the pipe contains disbonded and wrinkled coating, and some openings in the coating are present where the coating had begun to sag.

Photograph No. 27

Photograph No. 28

The photographs display overall views of the west side between 7:30 and 10:30 of the fractured pipe from 12' south to 16' south of the north girth weld, and from 16' south to 20' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The lower half of the pipe contains disbonded and wrinkled coating, along with some openings in the coating.

Photograph No. 29

Photograph No. 30

The photographs display overall views of the west side from 7:30 to 10:30 of the fractured pipe from 20' south to 24' south of the north girth weld, and from 24' south to 28' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The lower half of the pipe contains disbonded and wrinkled coating.

Photograph No. 31

Photograph No. 32

The photographs display overall views of the west side from 7:30 to 10:30 of the fractured pipe from 28' south to 31' south of the north girth weld, and from 31' south to 35' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The pipe had been sectioned transversely approximately 31' south of the north girth weld. The lower half of the pipe contains disbonded and wrinkled coating.

Photograph No. 33

Photograph No. 34

The photographs display overall views of the west side between 7:30 and 10:30 of the fractured pipe from 35' south to 39' south of the north girth weld, and from 39' south to 43' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The lower half of the pipe contains disbonded and wrinkled coating.

Photograph No. 35

Photograph No. 36

The photographs display overall views of the west side from 7:30 to 10:30 of the fractured pipe and adjacent intact pipe from 43' south to 47' south of the north girth weld, and from 47' south to 51' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The coating had been removed from the adjacent intact pipe prior to allow for sectioning. The lower half of the pipe contains disbonded and wrinkled coating.

Photograph No. 37

Photograph No. 38

The photographs display overall bottom views of the pipe from 4:30 to 7:30 o'clock adjacent to the fractured pipe from approximately 3' north of the north girth weld (-3') to the center of the north girth weld (0'), and the fractured pipe from the center of the north girth weld to 4' south of the north girth weld (+4'), respectively, in the as-received condition prior to removing the coating. The coating had been removed from the adjacent intact pipe prior to sectioning in the field. The coating on the lower half of the pipe is sagging and contains wrinkles.

Photograph No. 39

Photograph No. 40

The photographs display overall bottom views of the fractured pipe from 4:30 to 7:30 from 4' south to 8' south of the north girth weld, and from 8' south to 12' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The coating on the lower half of the pipe is sagging and contains wrinkles.

Photograph No. 41

Photograph No. 42

The photographs display overall bottom views of the fractured pipe from 4:30 to 7:30 from 12' south to 16' south of the north girth weld, and from 16' south to 20' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The coating on the lower half of the pipe contains wrinkles and has sagged.

Photograph No. 43

Photograph No. 44

The photographs display overall bottom views of the fractured pipe from 4:30 to 7:30 from 20' south to 24' south of the north girth weld, and from 24' to 28' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The coating on the lower half of the pipe contains a significant amount of wrinkles and has sagged quite a bit.

Photograph No. 45

Photograph No. 46

The photographs display overall bottom views of the fractured pipe from 4:30 to 7:30 from 28' south to 31' south of the north girth weld, and from 31' south to 35' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The fractured pipe was sectioned transversely approximately 31' south of the north girth weld into two sections.

Photograph No. 47

Photograph No. 48

The photographs display overall bottom views of the fractured pipe from 4:30 to 7:30 from 35' south to 39' south of the north girth weld, and from 39' south to 43' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The coating on the lower half of the pipe had sagged quite a bit and contains a significant amount of wrinkles.

Photograph No. 49

Photograph No. 50

The photographs display overall bottom views of the fractured pipe from 4:30 to 7:30 and the adjacent intact pipe from 43' south to 47' south of the north girth weld, and from 47' south to 51' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The coating on the lower half of the pipe contains a significant amount of wrinkles. The coating on the lower half of the pipe contains wrinkles.

Photograph No. 51

Photograph No. 52

The photographs display overall views of the east side of a pipe from 1:30 to 4:30 adjacent to the fractured pipe from approximately 3' north of the north girth weld (-3') to the center of the north girth weld (0'), and the fractured pipe from the center of the north girth weld to 4' south of the north girth weld (+4'), respectively, in the as-received condition prior to removing the coating. The lower half of the pipe contains wrinkled coating.

Photograph No. 53

Photograph No. 54

The photographs display overall views of the east side of the fractured pipe from 1:30 to 4:30 from 4' south to 8' south of the north girth weld, and from 8' south to 12' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The lower half of the pipe contains sagging and wrinkled coating.

Photograph No. 55

Photograph No. 56

The photographs display overall views of the east side of the fractured pipe from 1:30 to 4:30 from 12' south to 16' south of the north girth weld, and from 16' south to 20' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The lower half of the pipe contains sagging and wrinkled coating.

Photograph No. 57

Photograph No. 58

The photographs display overall views of the east side of the fractured pipe from 1:30 to 4:30 from 20' south to 24' south of the north girth weld, and from 24' south to 28' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The coating on the lower half of the pipe contains sagging and wrinkles.

Photograph No. 59

Photograph No. 60

The photographs display overall views of the east side of the fractured pipe from 1:30 to 4:30 from 28' south to 31' south of the north girth weld, and from 31' south to 35' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The lower half of the pipe contains sagging and wrinkled coating.

Photograph No. 61

Photograph No. 62

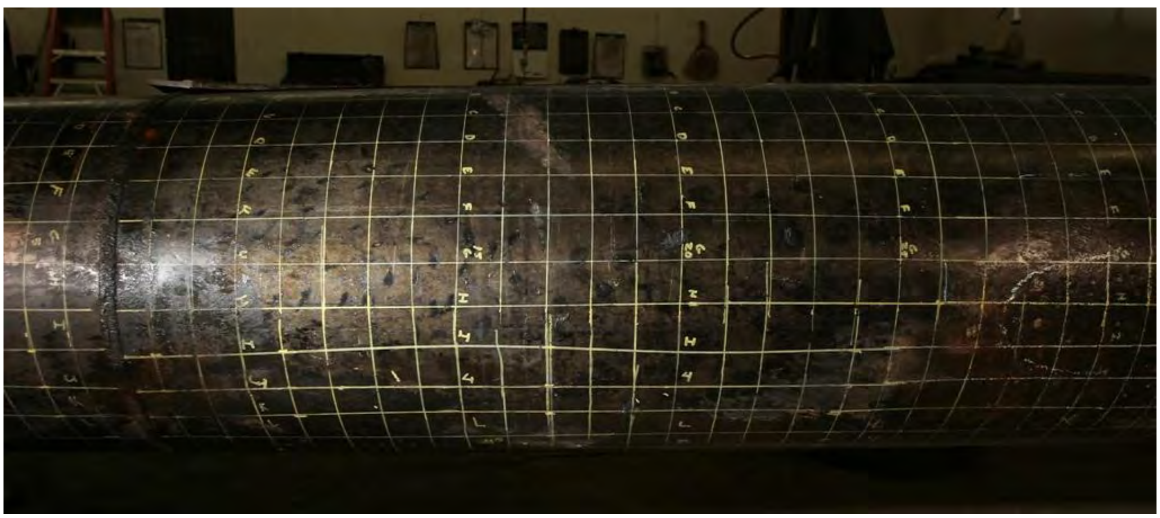
The photographs display overall views of the east side of the fractured pipe from 1:30 to 4:30 from 35' south to 39' south of the north girth weld, and from 39' south to 43' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The coating on the lower half is wrinkled and sagging.

Photograph No. 63

Photograph No. 64

The photographs display overall views of the east side of the fractured pipe from 1:30 to 4:30 and adjacent intact pipe from 43' south to 47' south of the north girth weld, and from 47' south to 51' south of the north girth weld, respectively, in the as-received condition prior to removing the coating. The coating had been removed from the adjacent intact pipe prior to sectioning. The coating on the lower half of the pipe is wrinkled and sagging.

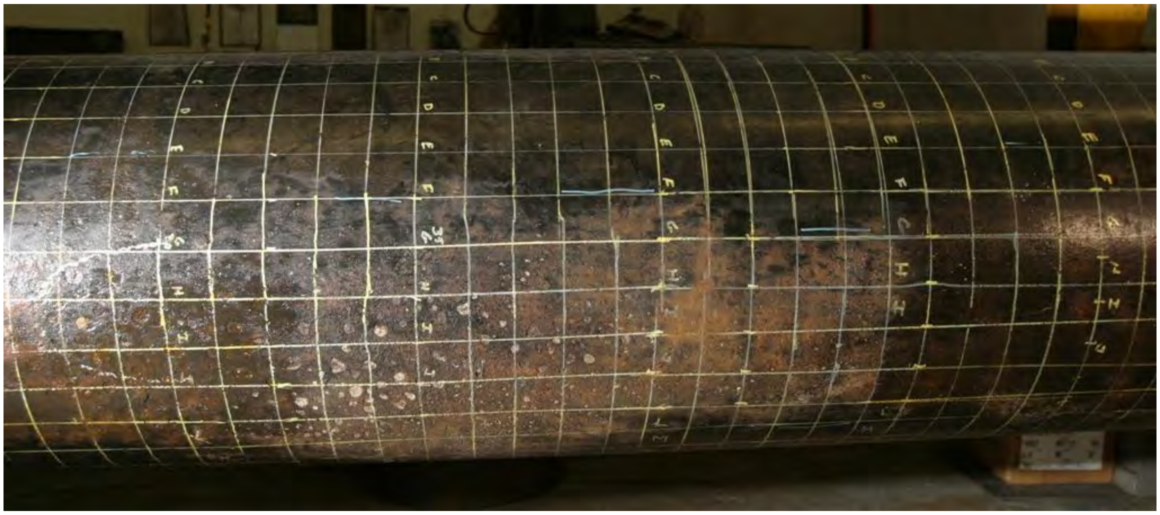
Photograph No. 65



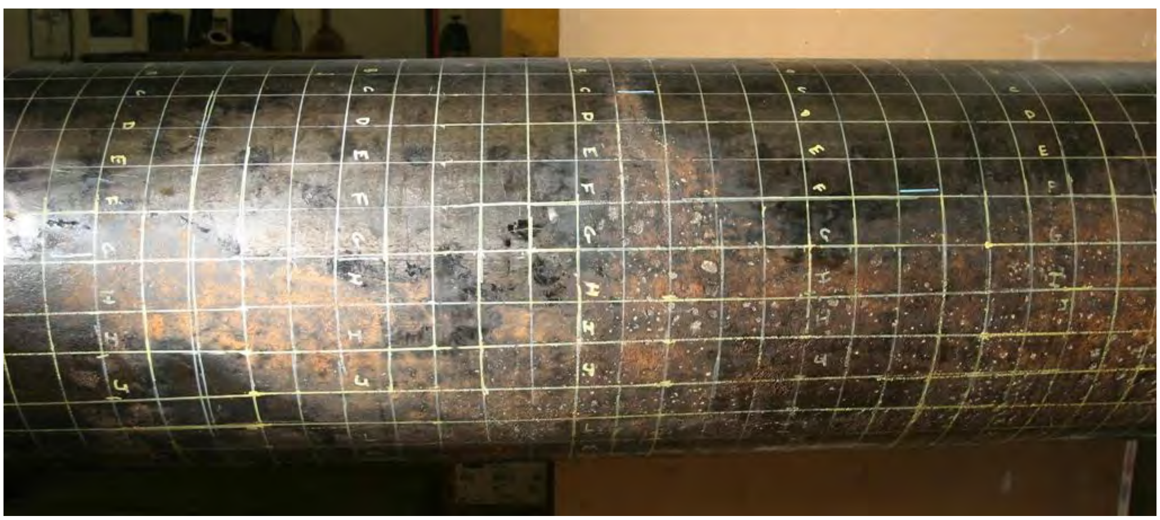
Photograph No. 66

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
All	-3' to 0'	No Corrosion Pitting Visible		
7:26 o'clock to 10:07 o'clock	0' to 4'	0.006"	0.017"	0.029"

The photographs display overall views of the west side of the pipe adjacent to the fractured area of the pipe, from approximately 3' north of the north girth weld (-3') to the center of the girth weld (0'), and the fractured pipe from the center of the girth weld to 4' south of the girth weld (+4'), respectively, after the removal of the coating. The lower half of the pipe shows corrosion pitting on the O.D. surface where the coating had wrinkled and sagged.



Photograph No. 67

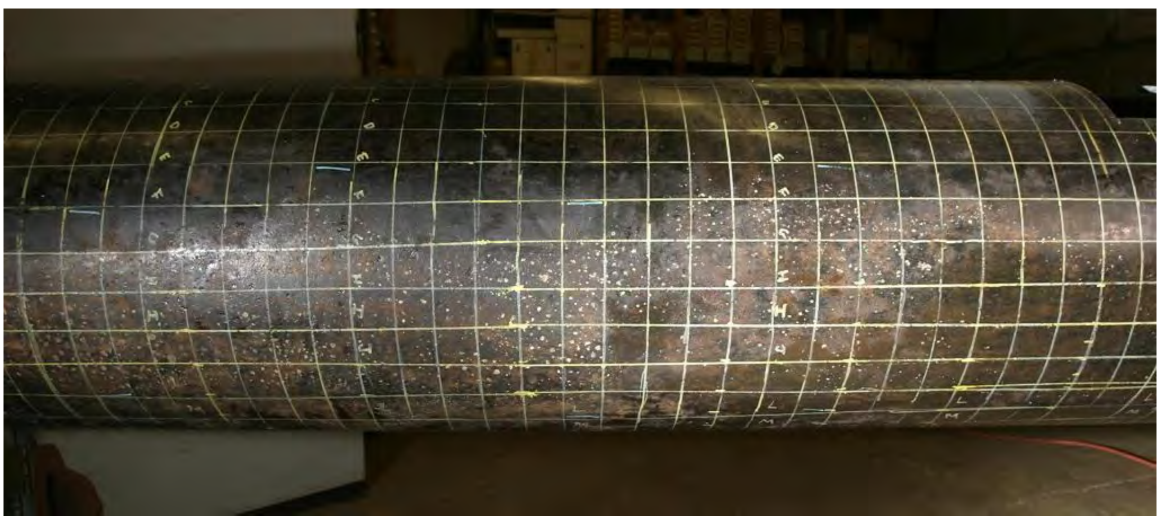


Photograph No. 68

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
6:41 o'clock to 10:07 o'clock	4' to 8'	0.002"	0.013"	0.037"
7:03 o'clock to 11:16 o'clock	8' to 12'	0.002"	0.011"	0.026"

The photographs display overall views of the west side of the fractured pipe from 4' south to 8' south of the north girth weld, and 8' south to 12' south of the north girth weld, respectively, after the removal of the coating. The lower half of the pipe shows corrosion pitting on the O.D. surface where the coating had wrinkled and sagged.

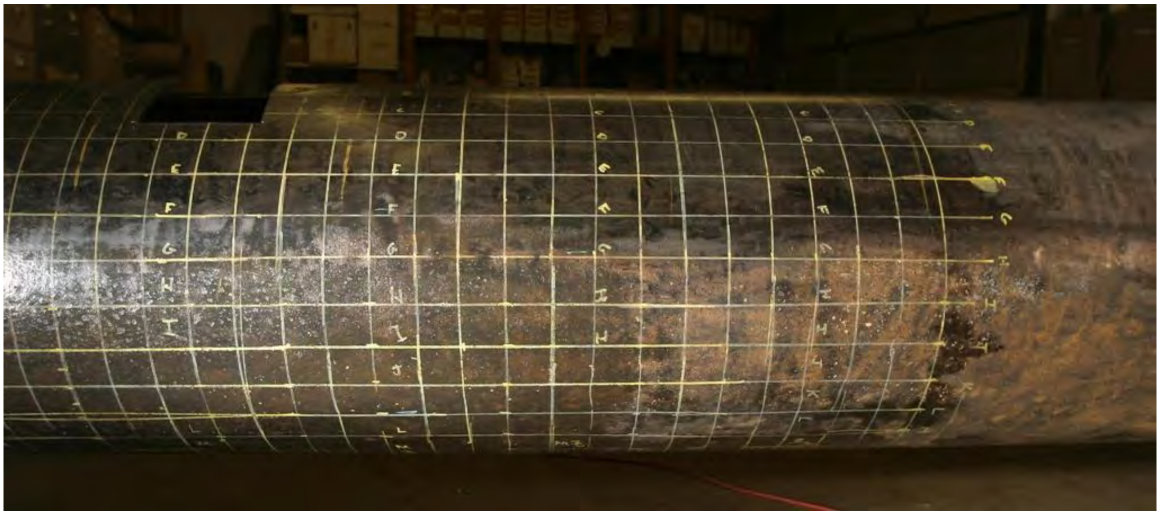
Photograph No. 69



Photograph No. 70

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
6:29 o'clock to 9:55 o'clock	12' to 16'	0.003"	0.017"	0.031"
6:52 o'clock to 10:07 o'clock	16' to 20'	0.006"	0.012"	0.021"

The photographs display overall views of the west side of the fractured pipe from 12' south to 16' south of the north girth weld, and 16' south to 20' south of the north girth weld, respectively, after the removal of the coating. The lower half of the pipe shows corrosion pitting on the O.D. surface where the coating had wrinkled and sagged.



Photograph No. 71

Photograph No. 72

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
7:15 o'clock to 9:55 o'clock	20' to 24'	0.005"	0.010"	0.021"
All	24' to 28'	No Corrosion Pitting Visible		

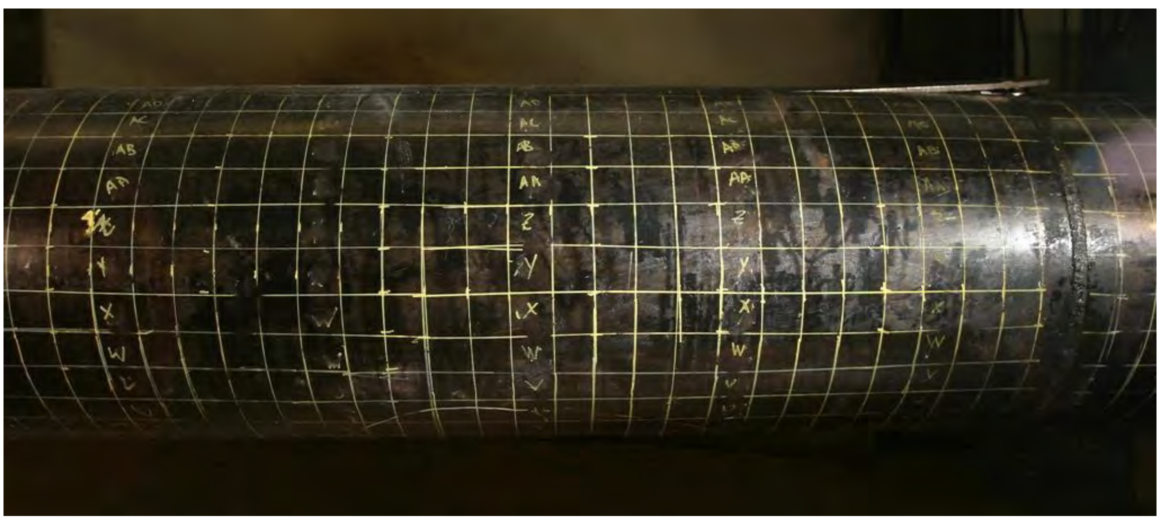
The photographs display overall views of the west side of the fractured pipe from 20' south to 24' south of the north girth weld, and 24' south to 28' south of the north girth weld, respectively, after the removal of the coating. The lower half of the pipe shows corrosion pitting on the O.D. surface where the coating had wrinkled and sagged.

Photograph No. 73

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
All	28' to 31'	No Corrosion Pitting Visible		

The photograph displays an overall view of the west side of the fractured pipe from 28' south to 31' south of the north girth weld, respectively, after the removal of the coating. The fractured pipe was sectioned in the field transversely approximately 31' south of the north girth weld to allow for removal of the fractured section of pipe. No corrosion pitting is visible on the O.D. surface near the transverse cut at the south end of the fractured section of the pipe.

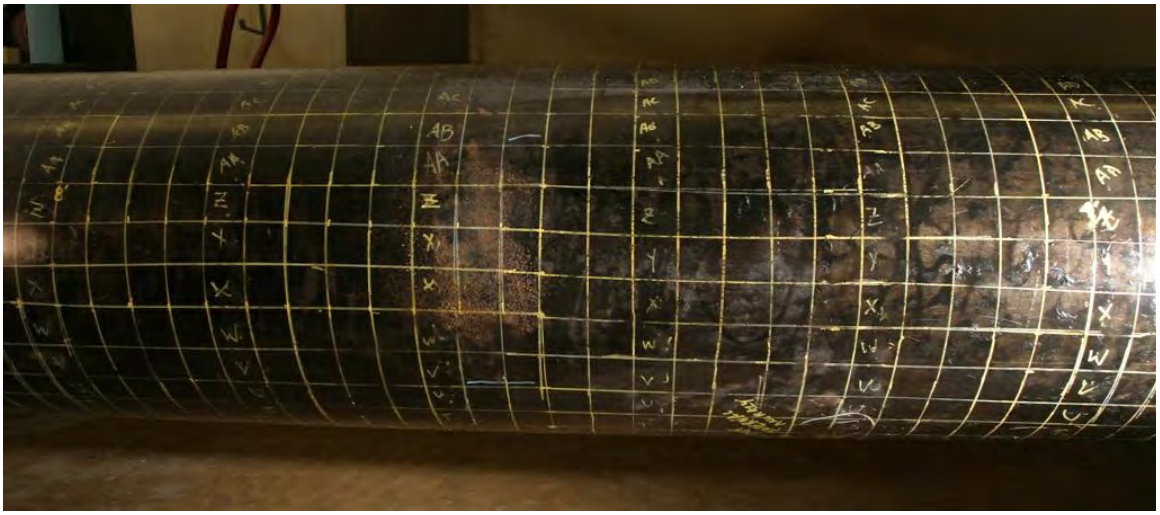
Photograph No. 74



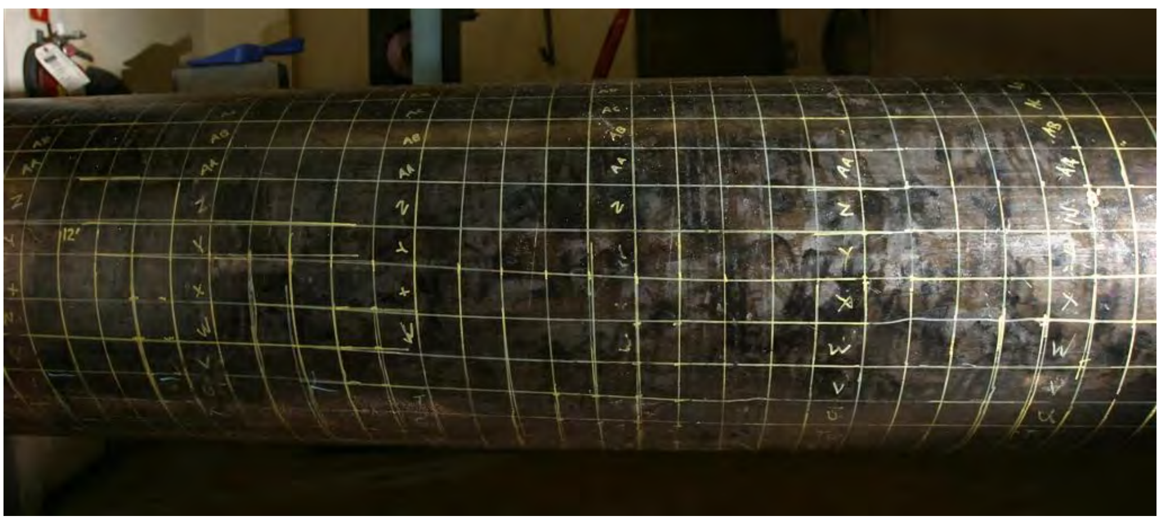
Photograph No. 75

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
All	-3' to 0'	No Corrosion Pitting Visible		
All	0' to 4'	No Corrosion Pitting Visible		

The photographs display overall views of the east side of the pipe adjacent to the fractured pipe from approximately 3' north of the girth weld (-3') to the center of the north girth weld (0'), and the fractured pipe from the center of the girth weld to 4' south of the north girth weld (+4'), respectively, after the removal of the coating. No corrosion pitting is visible on the O.D. surfaces on the fractured or intact pipe around the north girth weld.



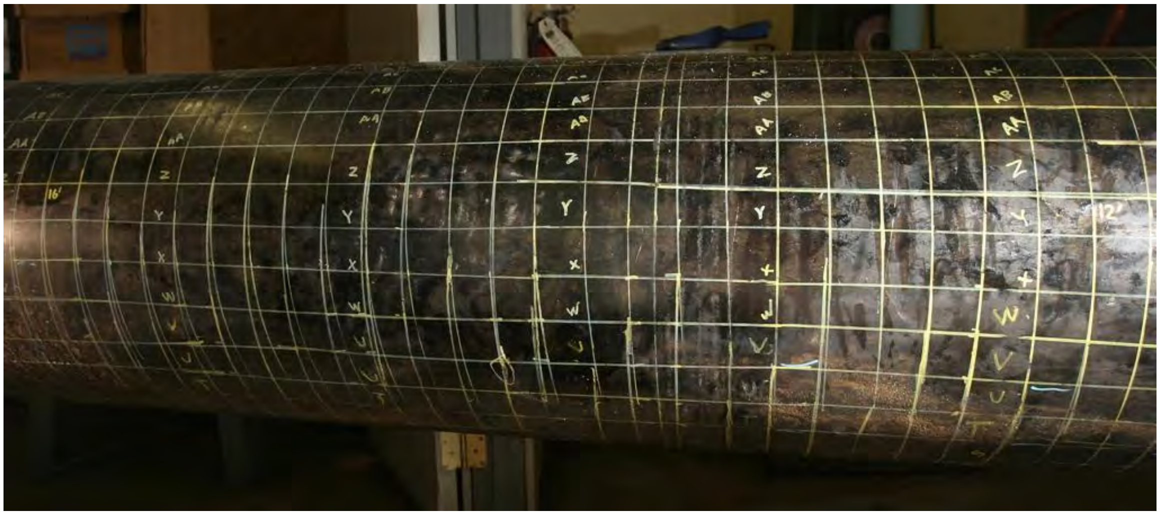
Photograph No. 76



Photograph No. 77

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
1:31 o'clock to 3:03 o'clock	4' to 8'	0.008"	0.013"	0.026"
3:49 o'clock to 4:57 o'clock	8' to 12'	0.004"	0.011"	0.022"

The photographs display overall views of the east side of the fractured pipe from 4' south to 8' south of the north girth weld, and 8' south to 12' south of the north girth weld, respectively, after the removal of the coating. The lower half of the pipe shows corrosion pitting on the O.D. surface where the coating had wrinkled and sagged.



Photograph No. 78

Photograph No. 79

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
3:03 o'clock to 4:57 o'clock	12' to 16'	0.003"	0.013"	0.033"
2:40 o'clock to 5:20 o'clock	16' to 20'	0.005"	0.015"	0.031"

The photographs display overall views of the east side of the fractured pipe from 12' south to 16' south of the north girth weld, and 16' south to 20' south of the north girth weld, respectively, after the removal of the coating. The lower half of the pipe shows corrosion pitting on the O.D. surface where the coating had wrinkled and sagged.

Photograph No. 80

Photograph No. 81

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
2:40 o'clock to 4:57 o'clock	20' to 24'	0.004"	0.020"	0.033"
All	24' to 28'	No Corrosion Pitting Visible		

The photographs display overall views of the east side of the fractured pipe from 20' south to 24' south of the north girth weld, and 24' south to 28' south of the north girth weld, respectively, after the removal of the coating. The lower half of the pipe shows corrosion pitting on the O.D. surface where the coating had wrinkled and sagged.

Photograph No. 82

Circumferential Location	Distance from North Girth Weld	Depth of Corrosion Pitting		
		Minimum	Average	Maximum
All	28' to 31'	No Corrosion Pitting Visible		

The photograph displays an overall view of the east side of the fractured pipe from 28' south of the north girth weld to 31' south of the north girth weld, respectively, after the removal of the coating. No corrosion pitting was visible on the O.D. surface near the transverse cut at the south end of the fractured section of the pipe.

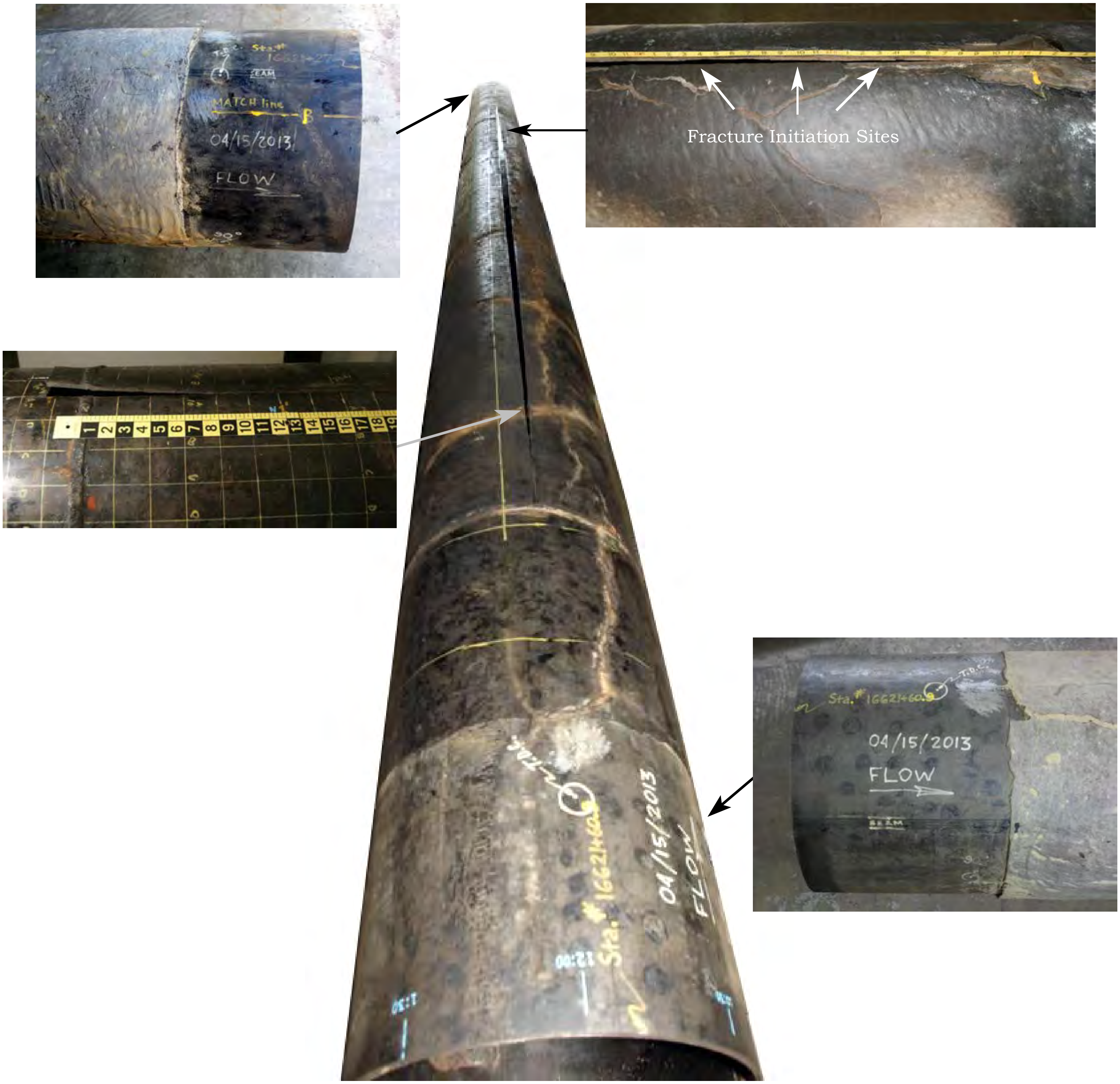
Photograph No. 83

Photograph No. 84

The photographs display representative areas of the I.D. surface at an intact area of the pipe, showing the smooth, shallow impressions that resulted from mechanical damage, most likely during the hot-rolling of the steel or manufacturing of the pipe. No evidence of corrosion pitting was observed on the I.D. surface.

Photograph No. 85

The photograph shows the displacement of the pipe by approximately 2-31/32" following sectioning through the intact portion of the adjoining pipe, indicative of the presence of significant residual stress.

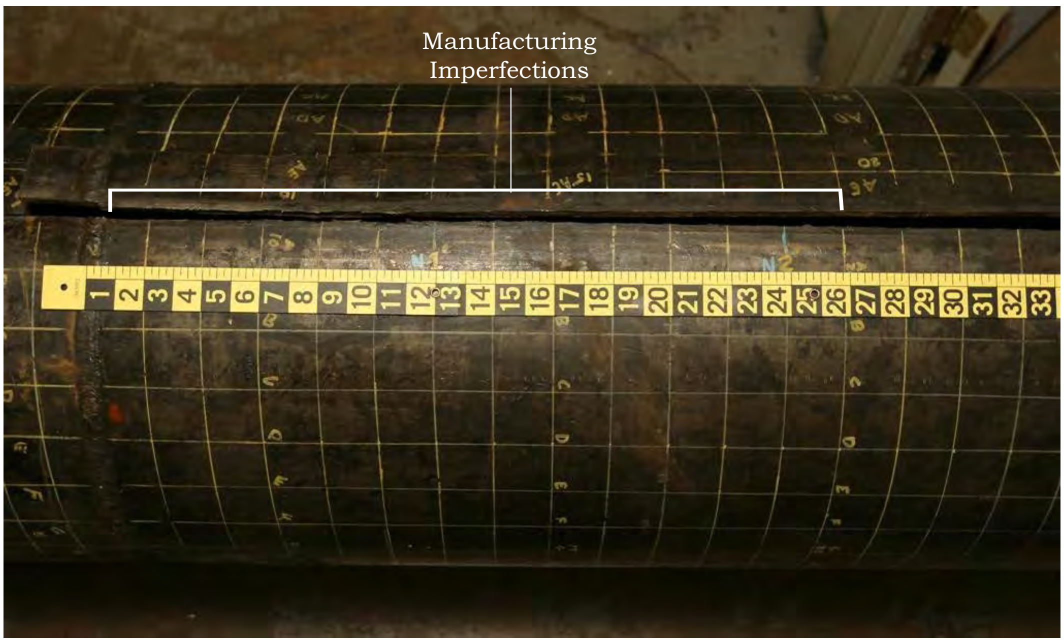


Photograph No. 86

The photographs display overall and close-up views of the 33' 11-1/2" long section of a fractured 20" O.D. x 0.312" wall pipe, which was removed from the Conway to Corsicana section of the Pegasus Crude Oil Pipeline at Milepost 314.77 in Mayflower, Arkansas.

Photograph No. 87

The photographs display overall and close-up views of one of the mating fracture faces from where the final rupture had occurred, resulting in the leakage of crude oil on March 29, 2013. The fractographs show the presence of hook cracks adjacent to the fusion line near the O.D. surface along the ERW seam, between a distance of 19' 10" and 21' 6-1/4" from the north girth weld, and radial lines emanating from the ends of the hook cracks as well as chevron marks revealing the crack propagation direction, which is denoted by the arrows.



Photograph No. 88

The photograph displays the presence of manufacturing imperfections that were found between a distance of 1/4" and 2' 2" from the north girth weld in the path of the final fracture.

Photograph No. 89

Photograph No. 90

The photographs display evidence of manufacturing imperfection, i.e. the upturned bands near the O.D. in the fracture path of the final fracture.

Photograph No. 91

Photograph No. 92

The photographs display the continuation of the manufacturing imperfections in the path of the final fracture.

Photograph No. 93

Photograph No. 94

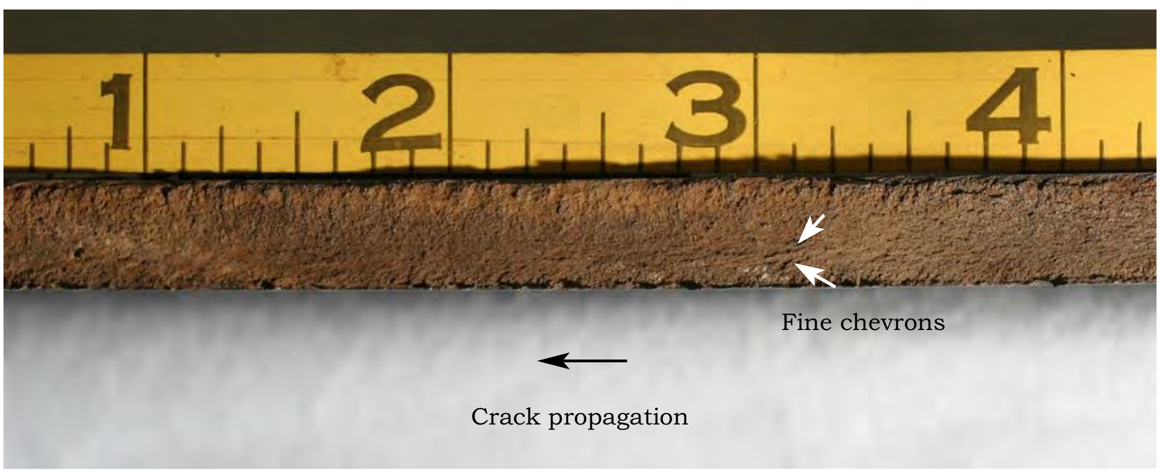
The photographs display evidence of chevron marks pointing downstream toward the fracture origins. The arrows point to some of the fine chevrons.

Photograph No. 95

Photograph No. 96

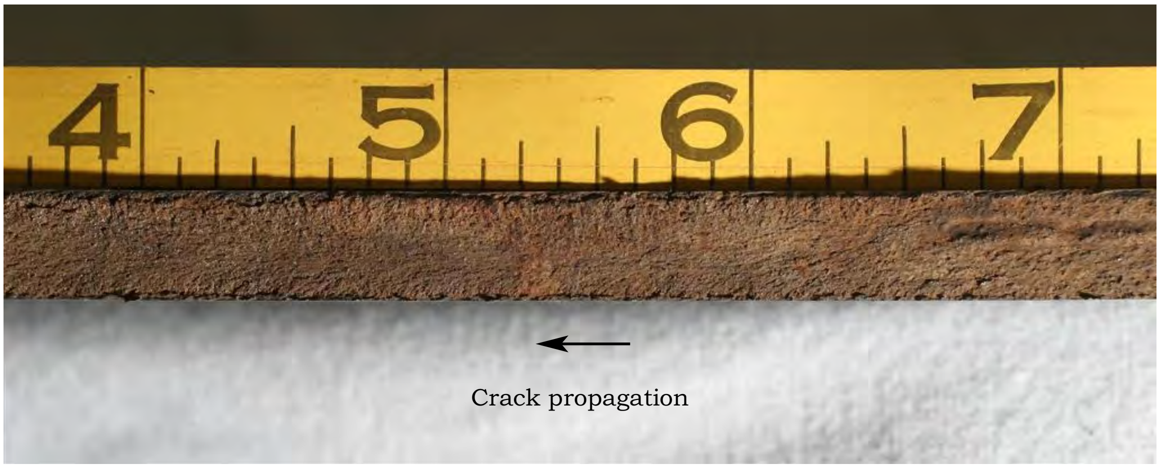
The photographs display the O.D. and I.D. surfaces of a section of the pipe that was removed between a distance of 18' 10" and 22' as measured from the north girth weld and which contained hook cracks along the ERW seam, from where the final failure initiated on March 29, 2013.

Photograph No. 97

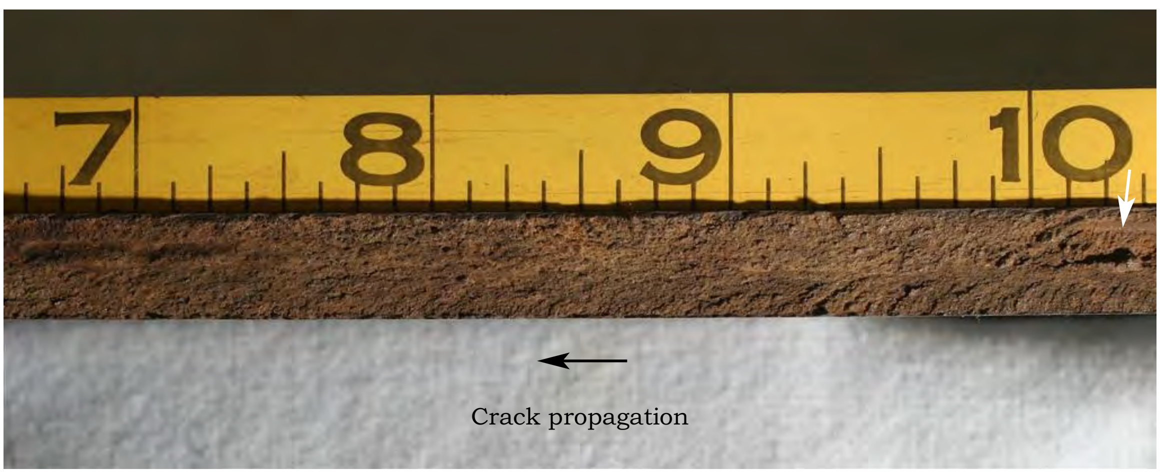


Photograph No. 98

The photographs display close-up views of the fracture face between a distance of 18' 10" and 19' 4" from the north girth weld of the pipe section, showing faint evidence of chevrons pointing toward the right (south end) near the fracture origins.

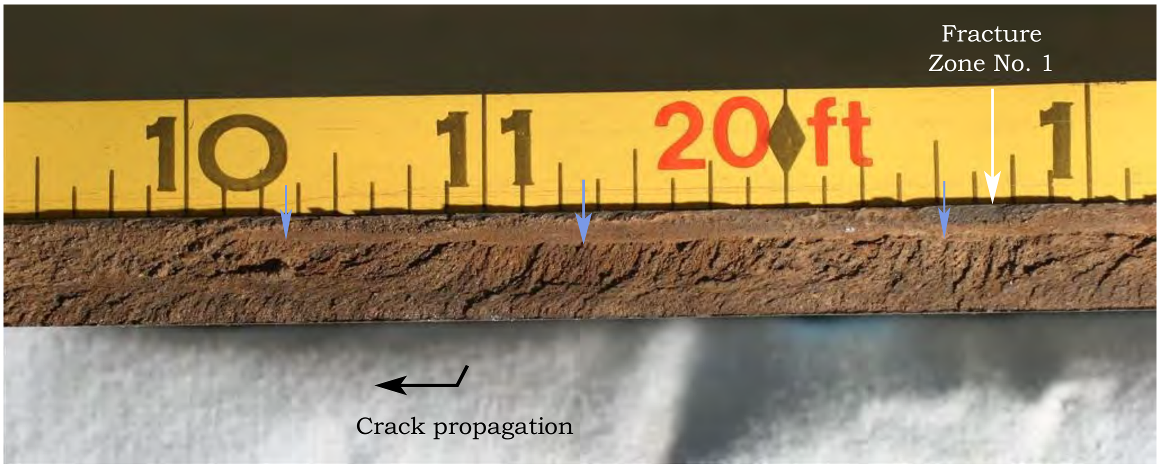


Photograph No. 99

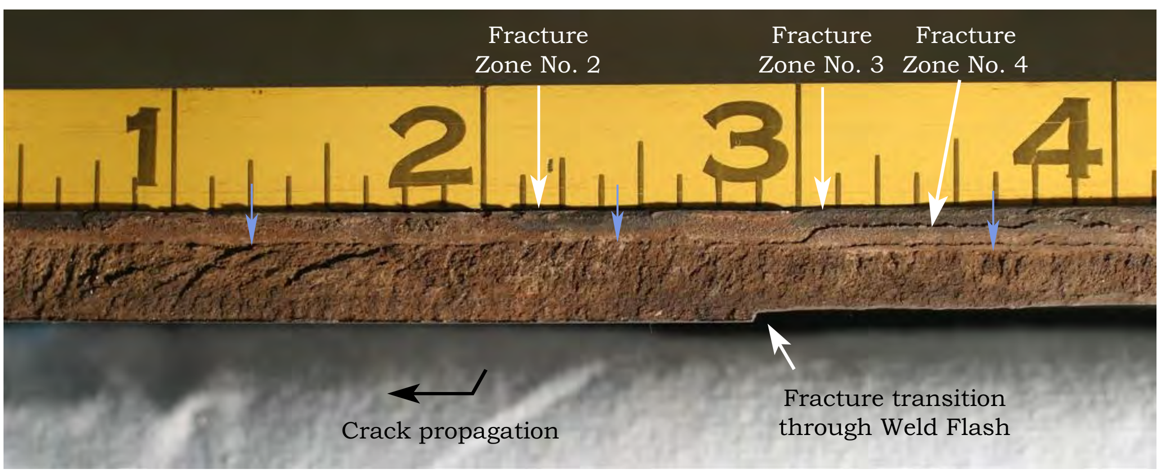


Photograph No. 100

The photographs display close-up views of the fracture face between a distance of 19' 4" and 19' 10" from the north girth weld of the pipe section, showing chevrons pointing toward the right (south end) near the fracture origins. The arrow in Photograph No. 100 points to the beginning of the hook cracks.

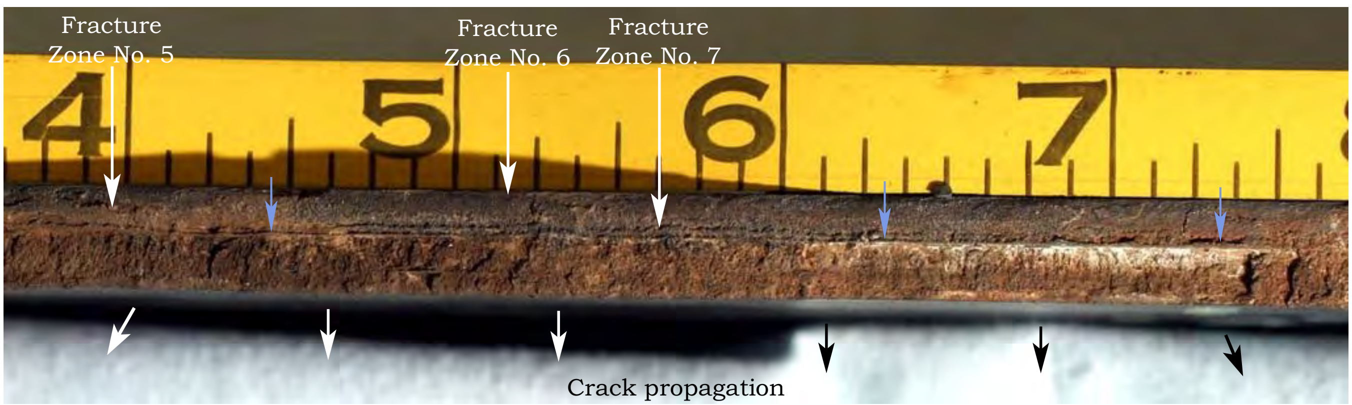


Photograph No. 101



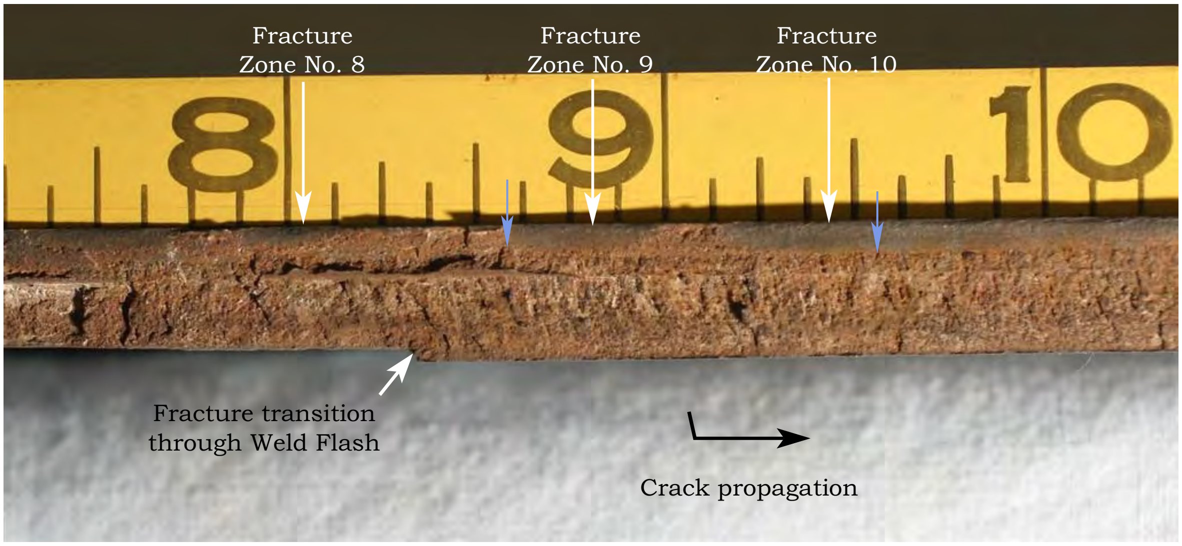
Photograph No. 102

The photographs display close-up views of the fracture face between a distance of 19' 10" and 20' 4" from the north girth weld, showing radial lines, marked by the blue arrows, which originated from hook cracks through the grain flow or banding formed during manufacturing the ERW seam.

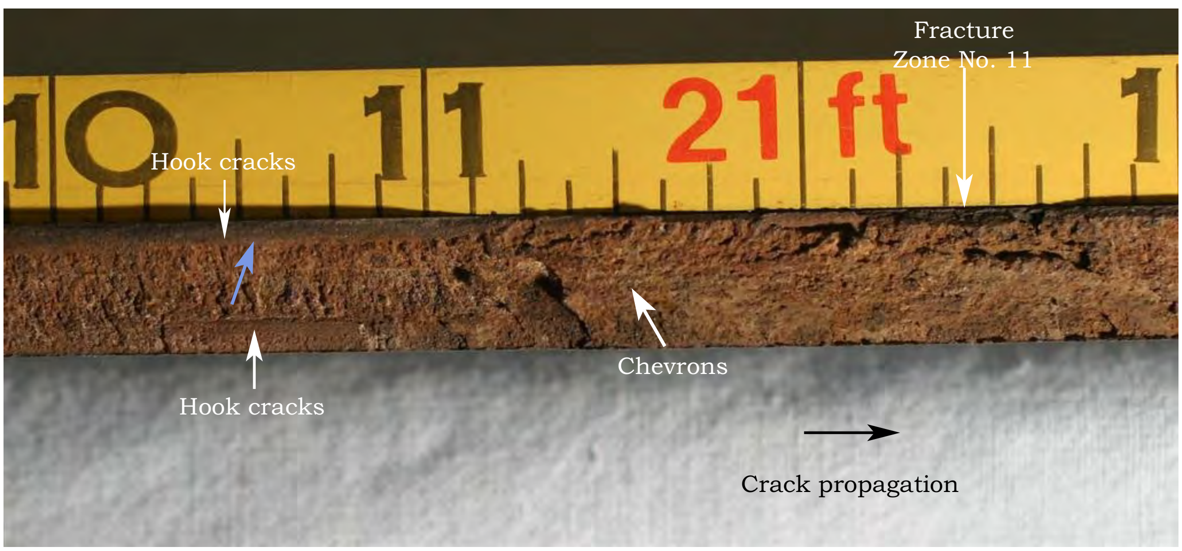


Photograph No. 103

The photograph displays a close-up view of the fracture face between a distance of 20' 4" and 20' 8" from the north girth weld, showing vertical radial lines emanating from the hook cracks, which are marked by the blue arrows, indicating the primary fracture initiation sites which resulted in the 22' 3" long fracture along the ERW seam of the 49' 9-1/2" long pipe.

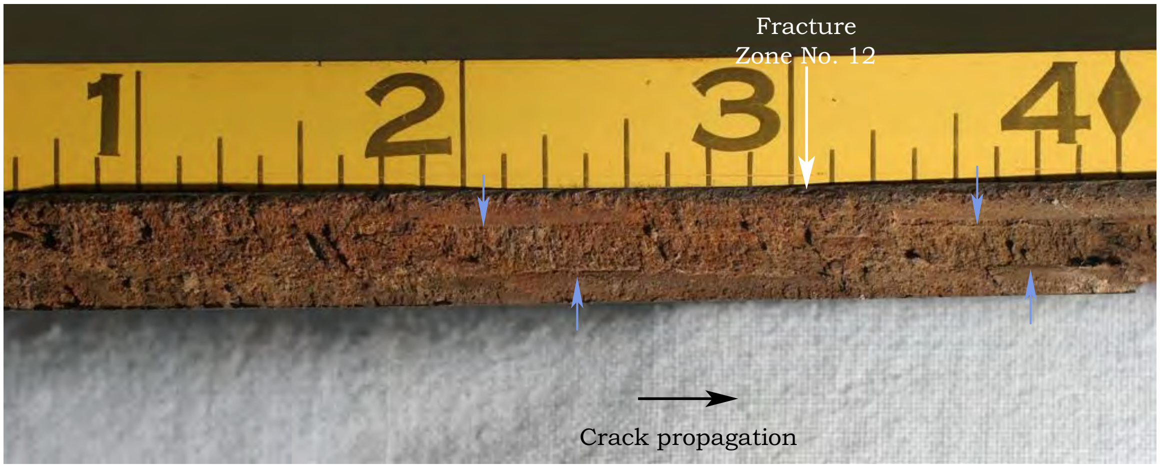


Photograph No. 104

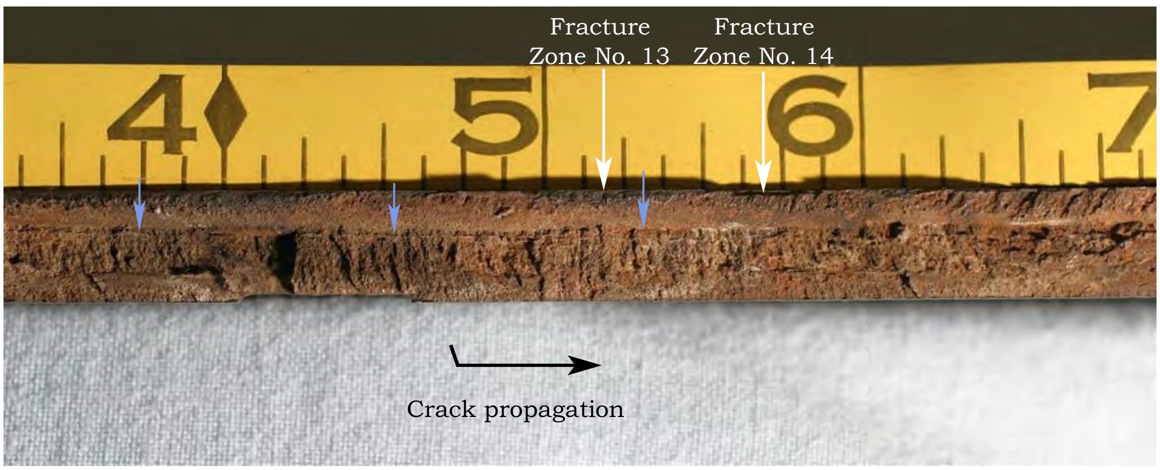


Photograph No. 105

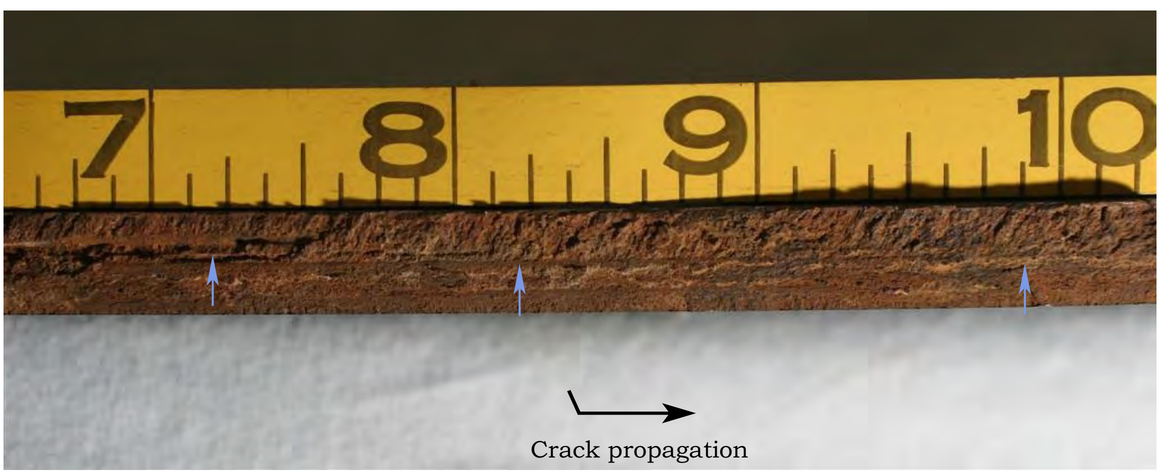
The photographs display close-up views of the fracture face between a distance of 20' 8" and 21' 1" from the north girth weld, showing radial lines emanating from the hook cracks, marked by the blue arrow, and chevrons pointing to the cracks, revealing some of the final fracture origins.



Photograph No. 106

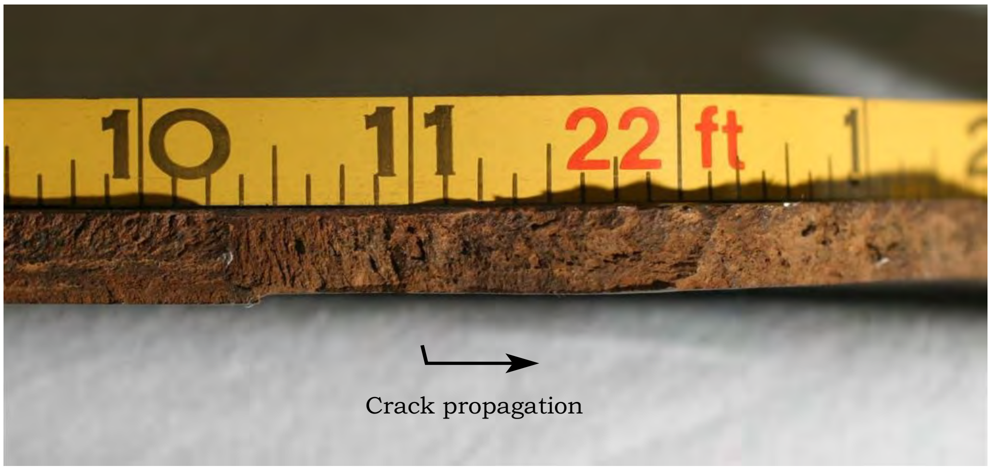


Photograph No. 107

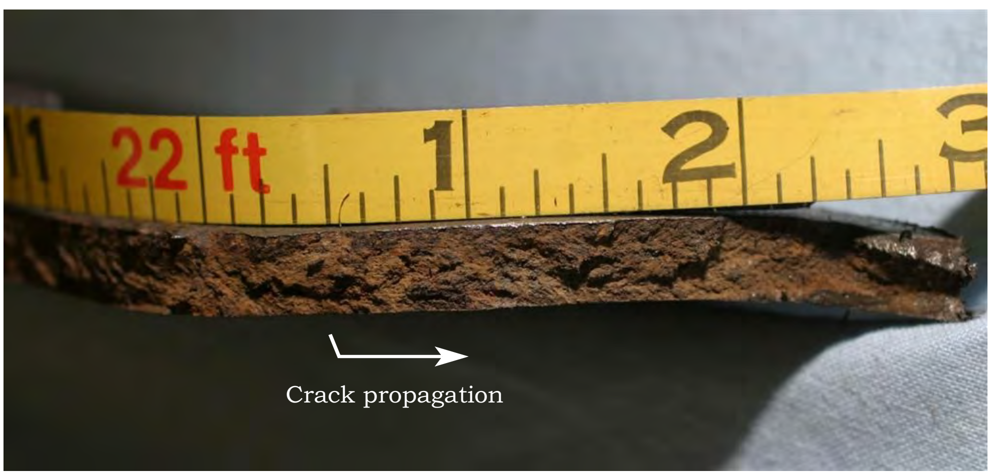


Photograph No. 108

The photographs display close-up views of the fracture face between a distance of 21' 1" and 21' 10" from the north girth weld showing radial lines emanating from the hook cracks. The blue arrows point to the radial lines, indicative of some of the final fracture initiation sites.



Photograph No. 109



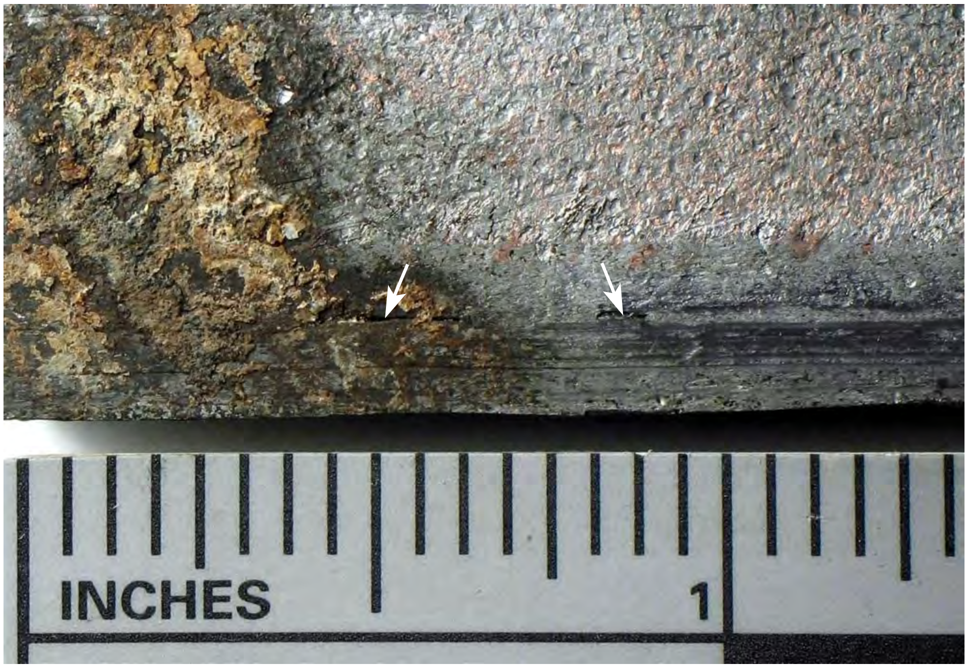
Photograph No. 110

The photographs display close-up views of the fracture face between a distance of 21' 10" and 22' from the north girth weld, showing the final fracture which terminated in the base metal of the pipe, diagonally to a distance of approximately 3".

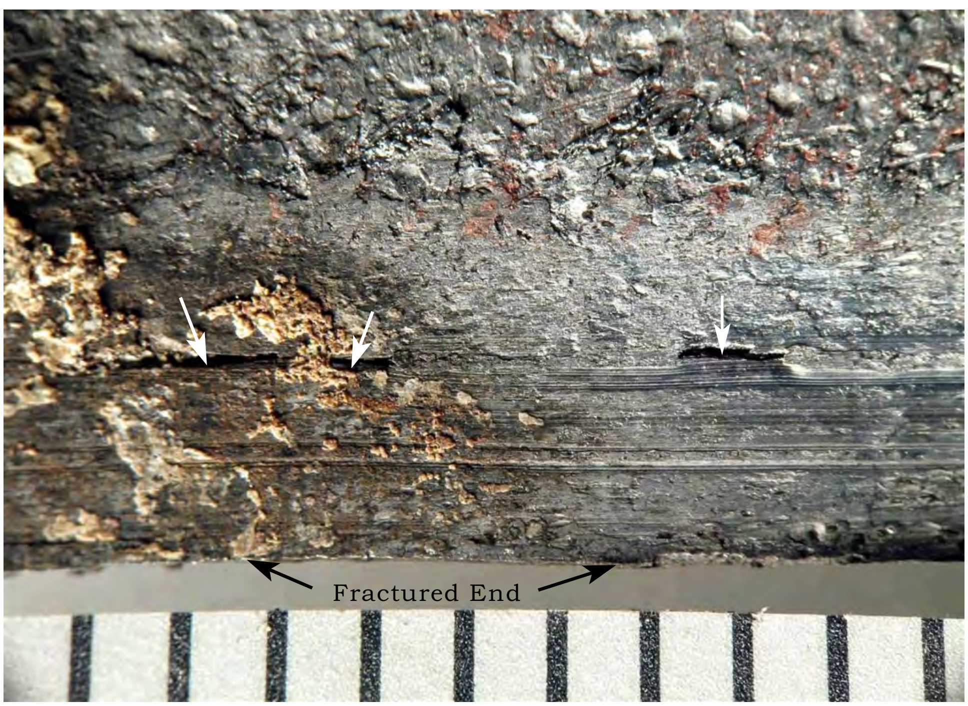
Photograph No. 111

Photograph No. 112

The photographs display the O.D. and I.D. surfaces adjacent to one of the mating fracture faces which contained multiple hook cracks. The arrow points to an area where the coating was apparently damaged prior to the incident.



Photograph No. 113



Photograph No. 114

The photographs of the outside surface of the fractured ERW seam at a distance between 20' 4-1/2" and 20' 6" from the north girth weld show evidence of what appears to be crack or melting caused by copper electrode contacts during the ERW seam fabrication. The arrows point to these imperfections.

Photograph No. 115

Photograph No. 116

The photographs display close-up views of the copper electrode contact marks in the heat-affected zone of the ERW seam, at the arrow, on the O.D. surface and the presence of copper.

Photograph No. 117

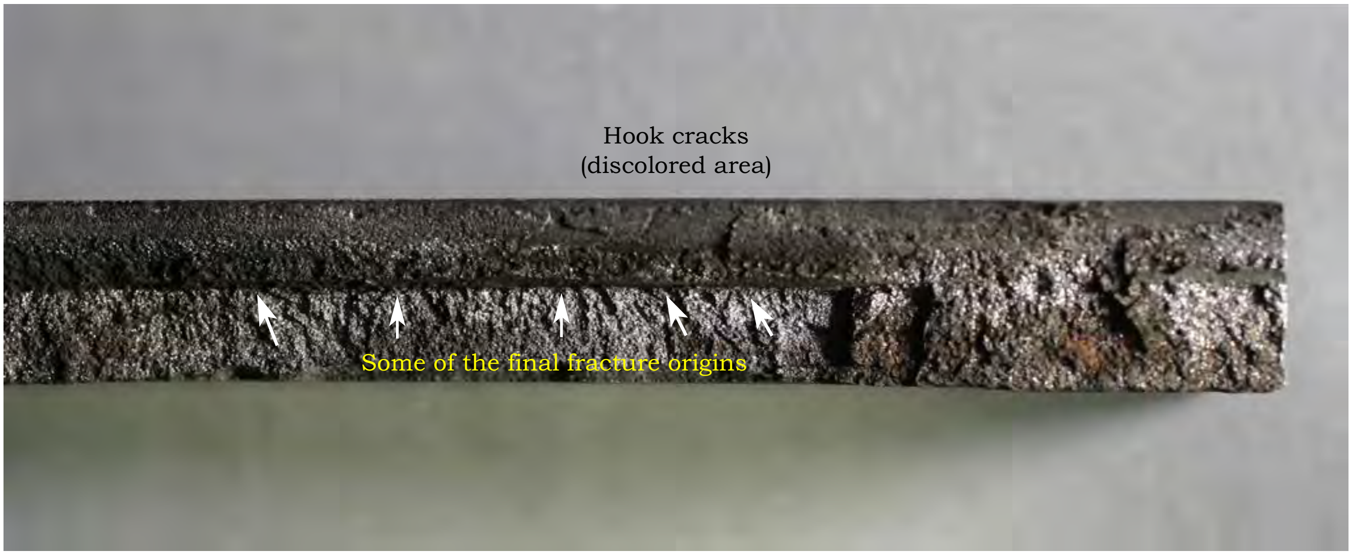
Photograph No. 118

The photographs display the mating fracture faces between a distance of approximately 20' 2-1/2" and 20' 8" from the north girth weld, revealing hook cracks in the heat-affected zone of the ERW seam to a maximum depth of 0.150" as measured from the O.D. surface, and vertical lines emanating from the tips of the hook cracks, indicative of the final fracture origin sites.

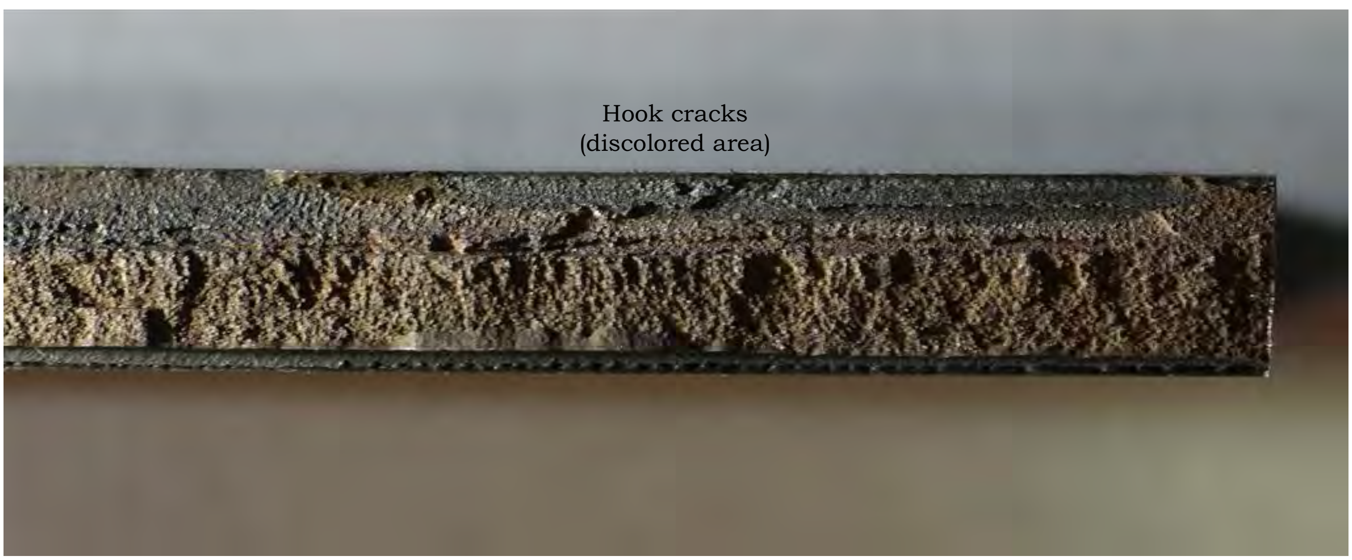
Photograph No. 119

Photograph No. 120

The photographs display the mating fracture faces revealing some of the fracture origin site(s) at a distance of approximately 20' 5-5/16" from the north girth weld, which were later examined at higher magnifications using a Scanning Electron Microscope (SEM) to characterize the fracture morphologies.

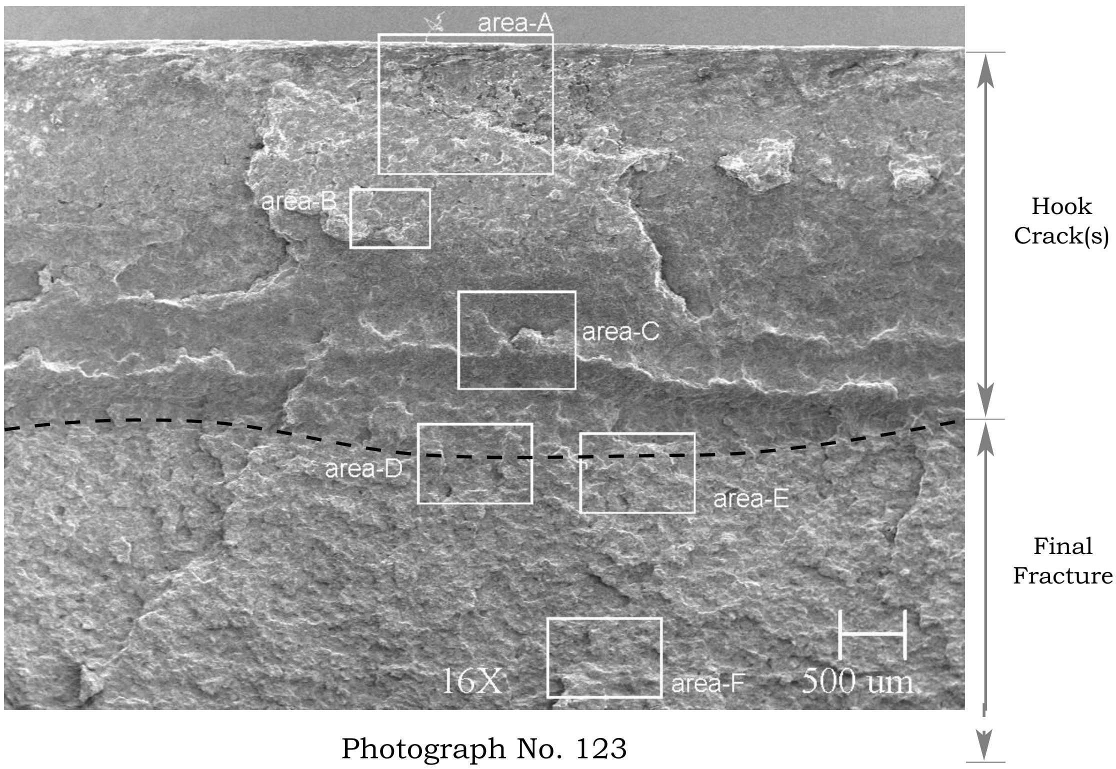


Photograph No. 121



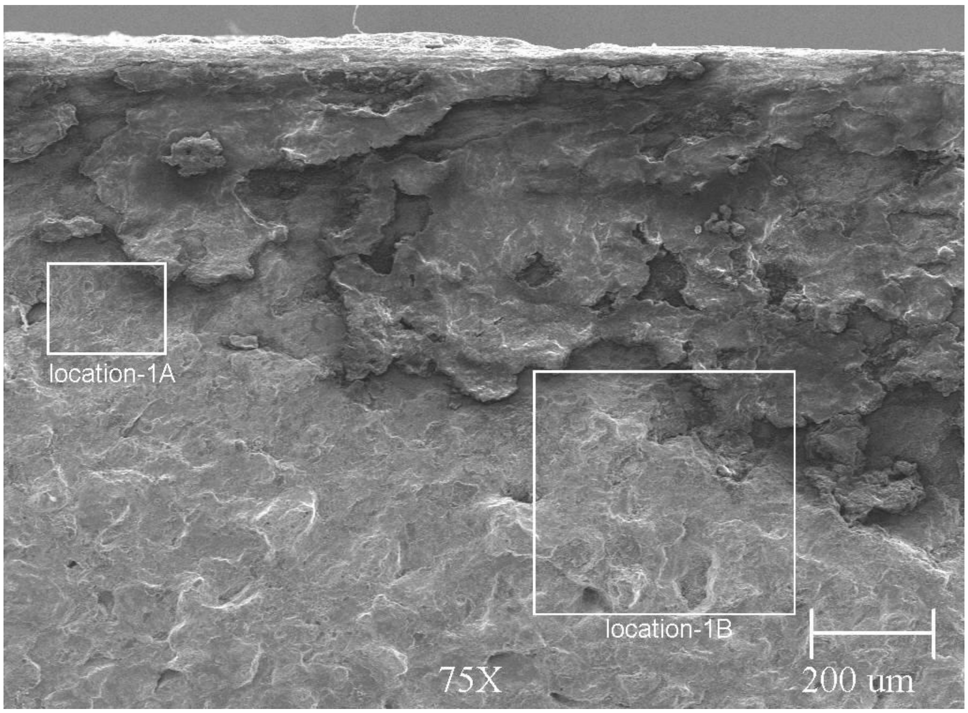
Photograph No. 122

The photographs display the mating fracture faces revealing some of the fracture origin sites at a distance between 20' 5-3/4" and 20' 7-1/2" from the north girth weld, which were later examined at higher magnifications using an SEM to characterize the fracture morphologies.



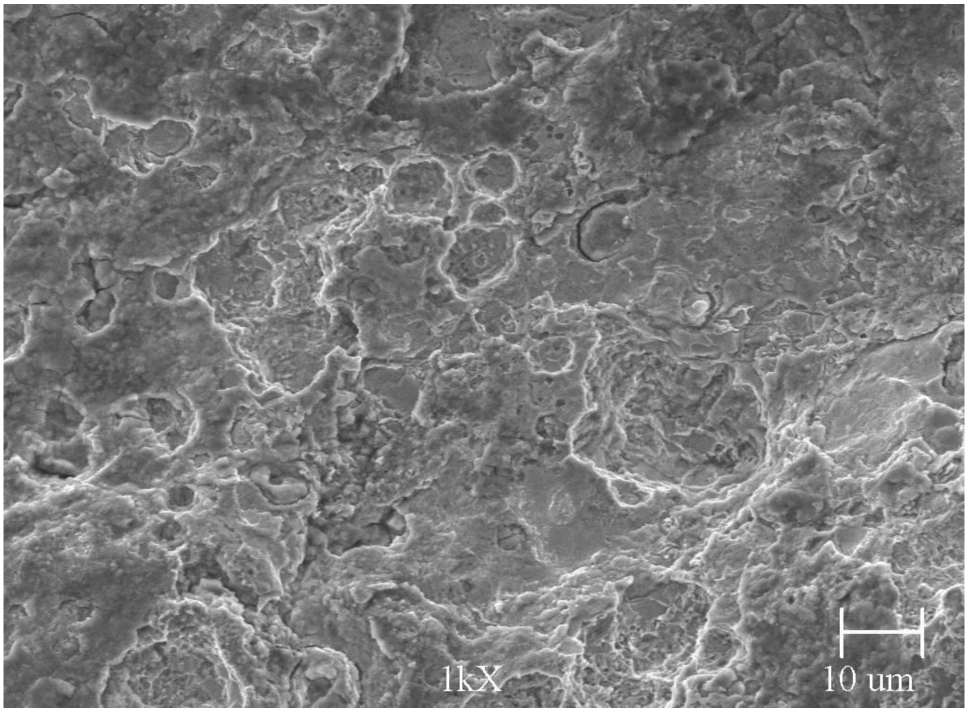
Photograph No. 123

The SEM fractograph taken of one of the final fracture origin sites at a distance of 20' 5-5/16" from the north girth weld shows an hook crack and the final fracture zone. The fracture locations within the rectangles were examined at high magnifications to further characterize the fracture morphologies. The dotted line denotes the transition zone between the hook cracks and the final fracture.

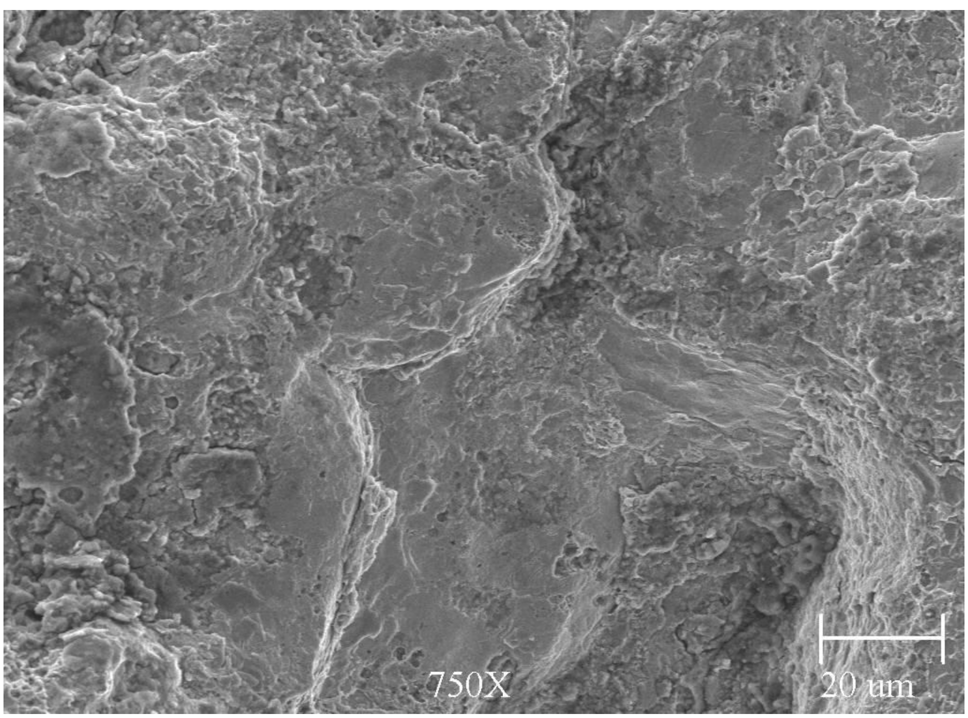


Area-A
Photograph No. 124

The SEM fractograph taken of the Area-A of the hook crack near the O.D. surface, as displayed in Photograph No. 123, displays essentially a nondescript featureless fracture surface. Note the absence of any fracture features, likely due to the metal-to-metal contact from the mating fracture faces of the crack and post-crack oxidation. The fracture locations labeled as Location-1A and Location-1B were examined at higher magnifications to further characterize the fracture morphology.

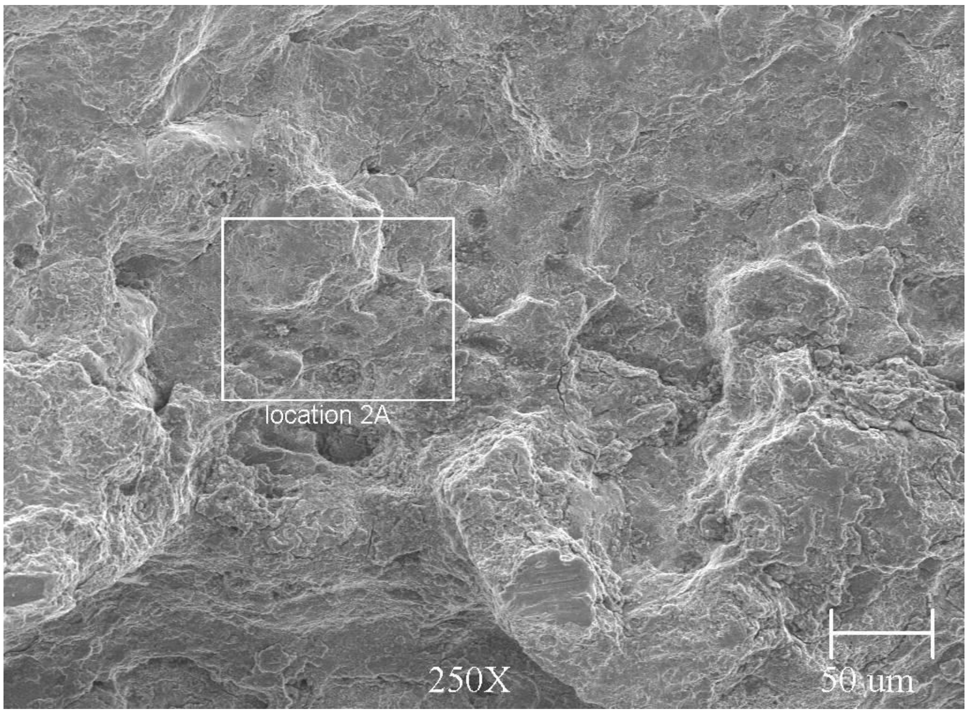


Area-A, Location-1A
Photograph No. 125



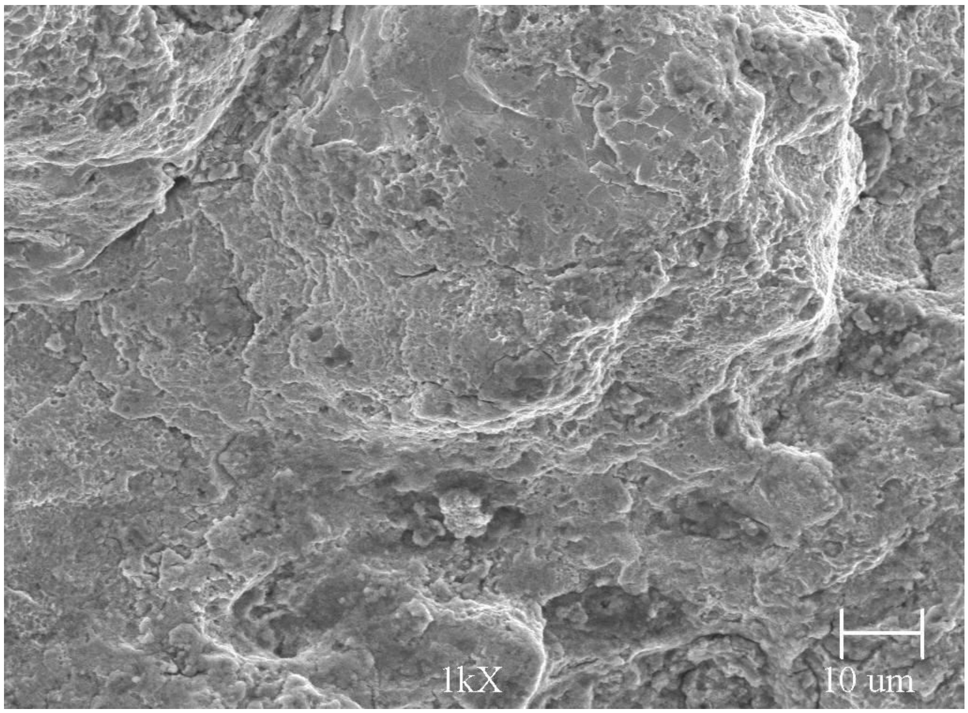
Area-A, Location-1B
Photograph No. 126

The SEM fractographs of the two (2) fracture locations labeled as Location-1A and Location-1B in Area-A of the hook crack zone near the O.D. display tightly adhered oxidation product, suggesting that the crack had occurred some time prior to the final fracture.



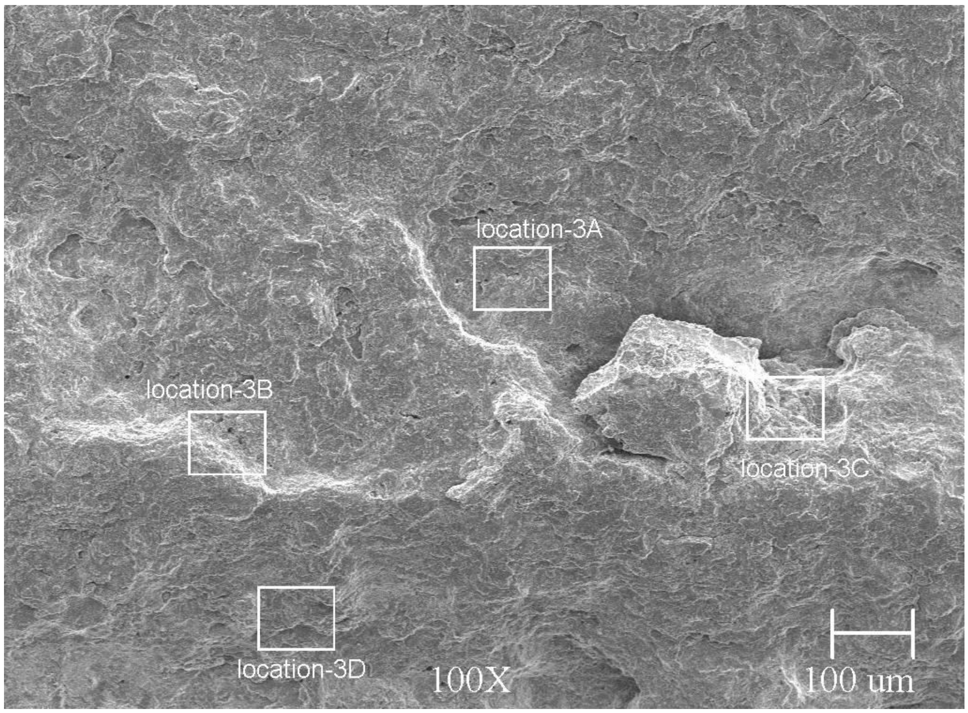
Area-B
Photograph No. 127

The SEM fractograph taken of the Area-B of the hook crack zone, as displayed in Photograph No. 123, reveals a nondescript, featureless fracture surface. The fracture location labeled as Location-2A was examined at higher magnification to further characterize the fracture morphology.



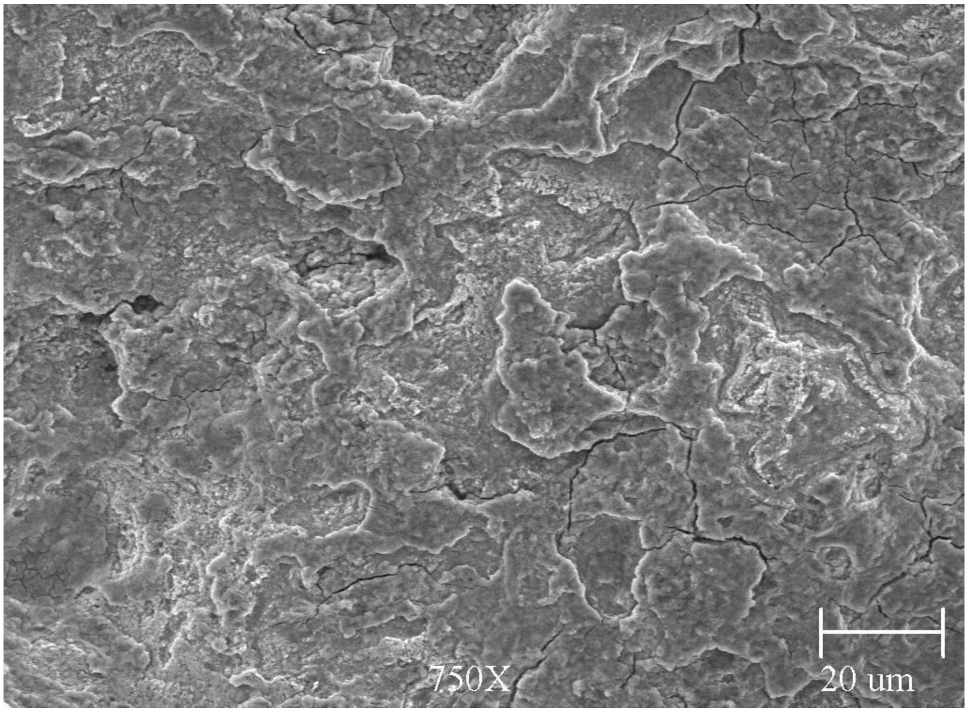
Area-B, Location-2A
Photograph No. 128

The SEM fractograph taken of the Area-B at Location-2A of the hook crack zone, as displayed in Photograph No. 127, reveals tightly adhered oxidation product on the fracture surface.

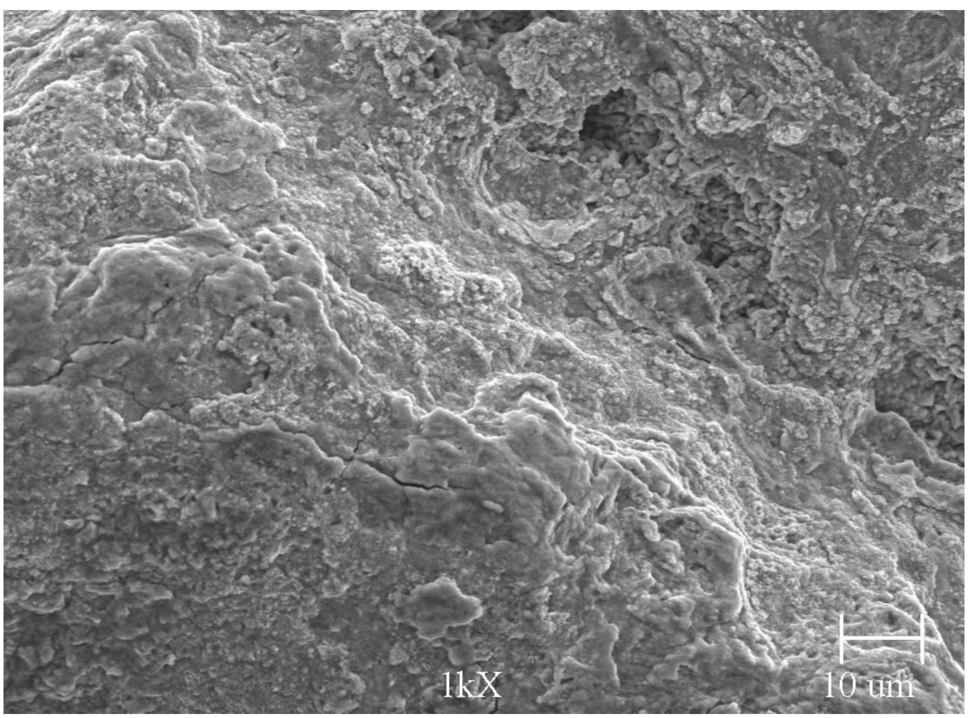


Area-C
Photograph No. 129

The SEM fractograph taken of the Area-C of the hook crack zone, as displayed in Photograph No. 123, reveals a nondescript, featureless fracture surface. The fracture locations, labeled as Location-3A, Location-3B, Location-3C, and Location-3D, were examined at higher magnifications to further characterize the fracture morphologies.

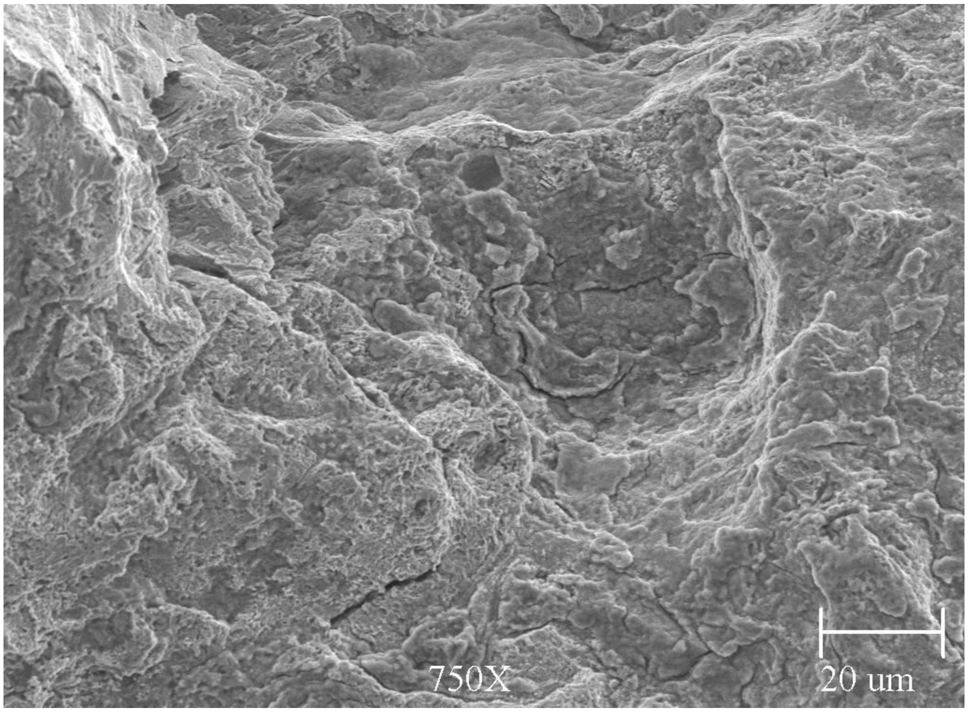


Area-C, Location-3A
Photograph No. 130

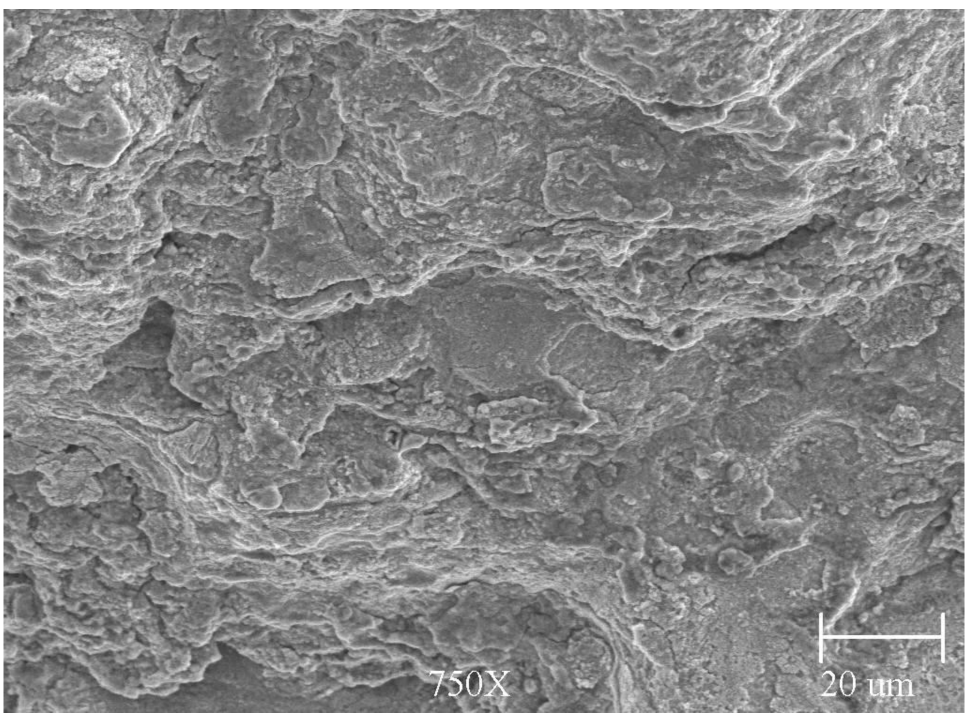


Area-C, Location-3B
Photograph No. 131

The SEM fractographs taken of the Area-C at Location-3A and Location-3B of the hook crack zone, as displayed in Photograph No. 129, reveal tightly adhered oxidation product.

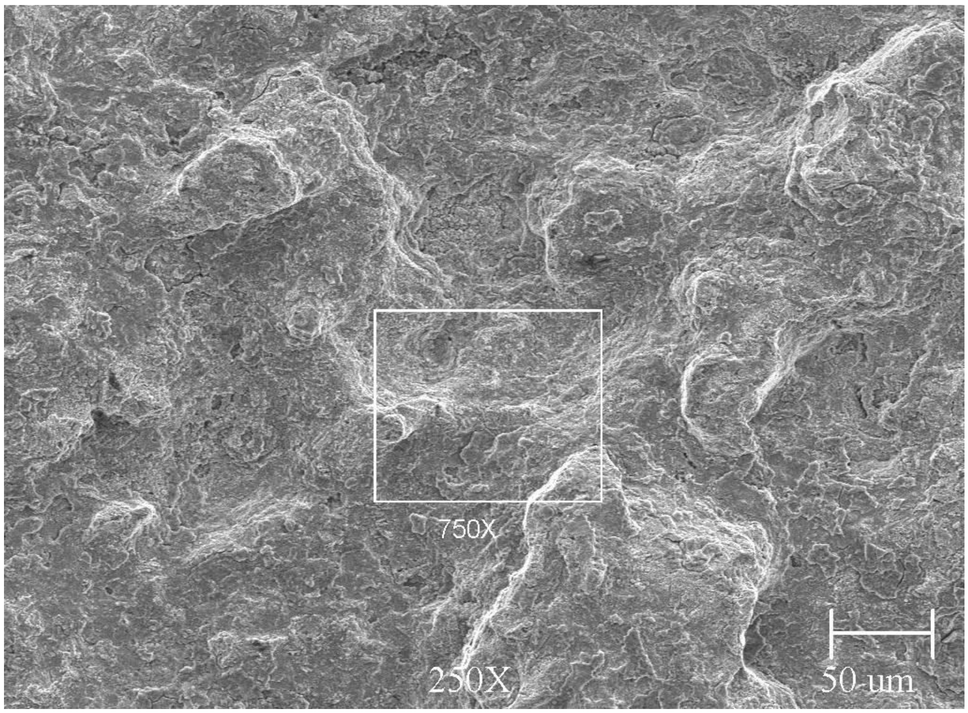


Area-C, Location-3C
Photograph No. 132



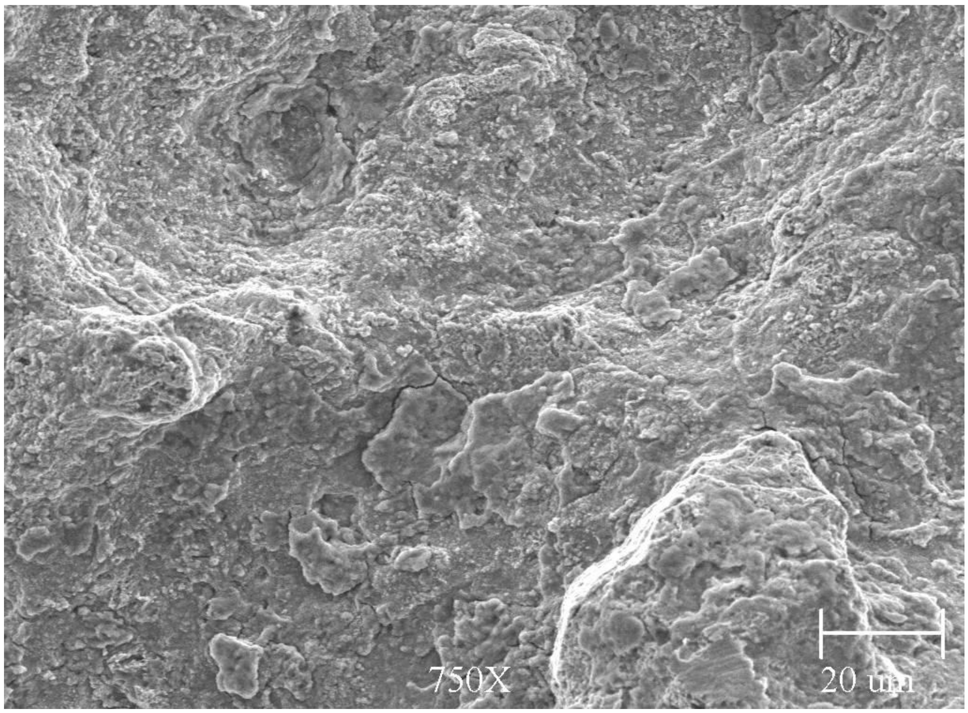
Area-C, Location-3D
Photograph No. 133

The SEM fractographs taken of the Area-C at Location-3C and Location-3D of the hook crack zone, as displayed in Photograph No. 129, reveal tightly adhered oxidation product.



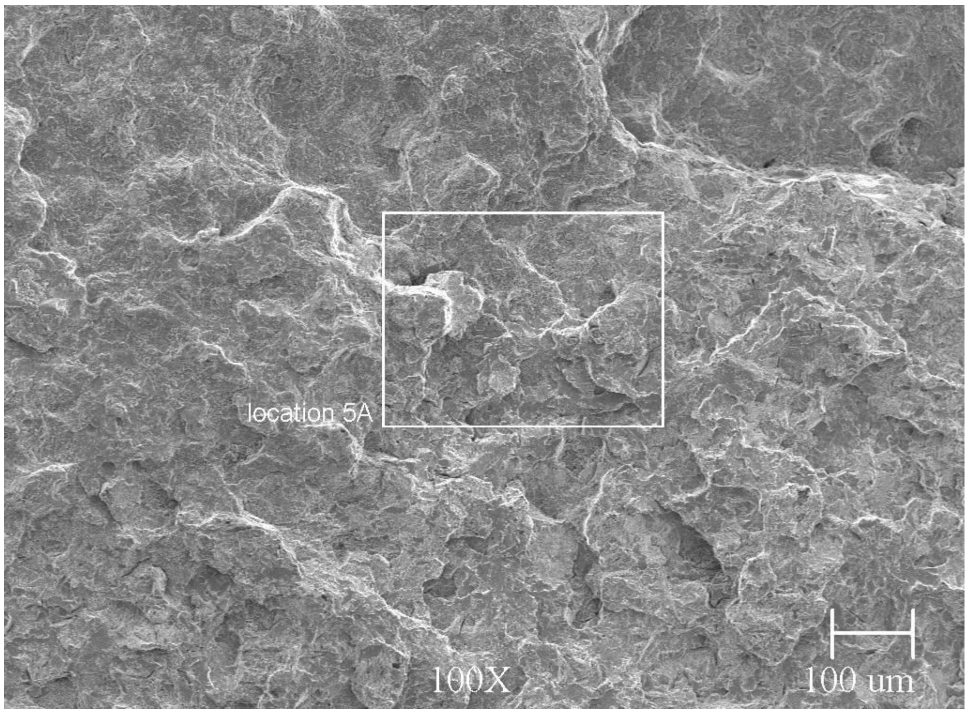
Area-D
Photograph No. 134

The SEM fractograph taken of the Area-D of the hook crack zone, as displayed in Photograph No. 123, reveals a nondescript, featureless fracture surface. The fracture location within the rectangle was examined at a higher magnifications to characterize the fracture morphology.



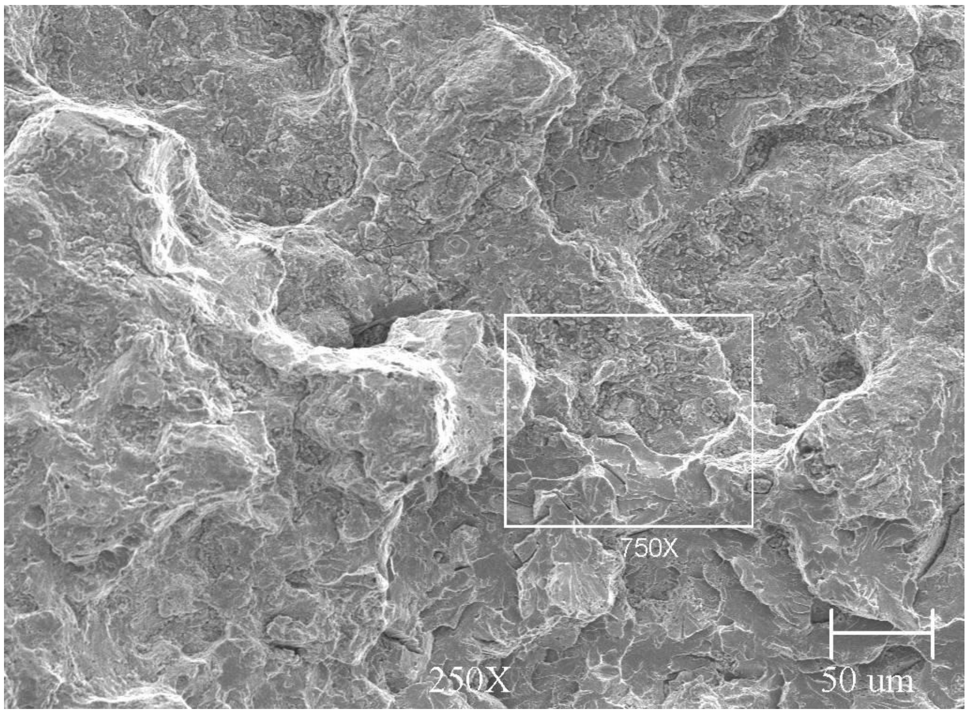
Area-D within the rectangle
Photograph No. 135

The SEM fractograph taken of the Area-D within the rectangle of the hook crack zone, as displayed in Photograph No. 134, reveals tightly adhered oxidation product.



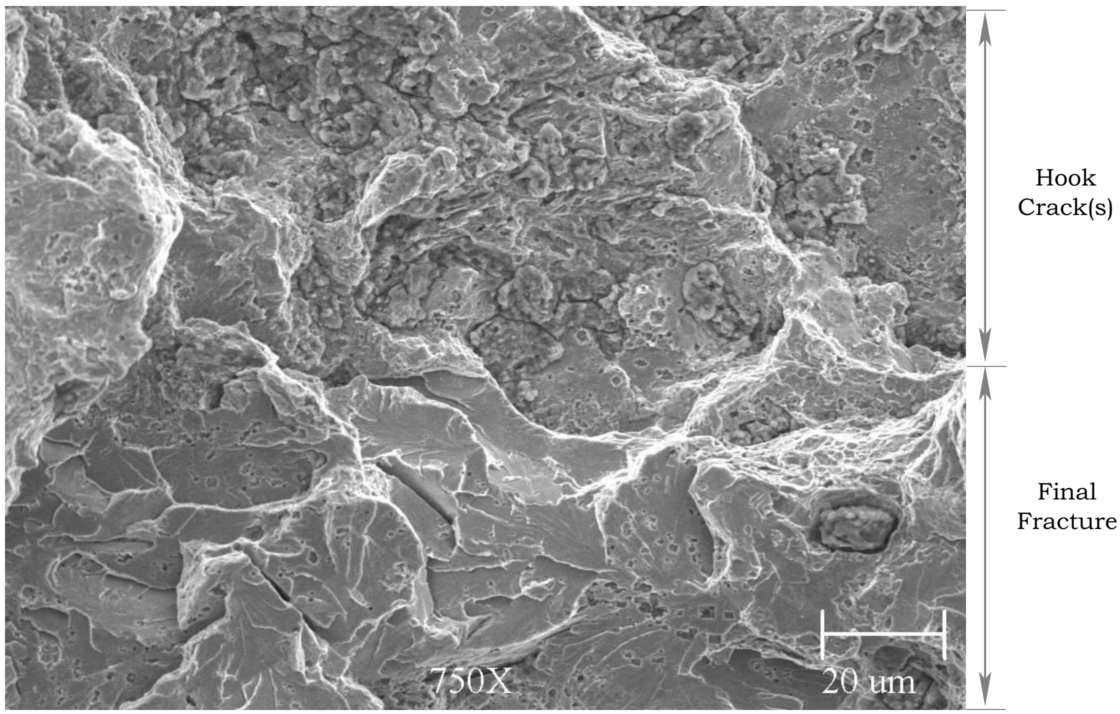
Area-E
Photograph No. 136

The SEM fractograph taken of the Area-E in the transition zone between the hook crack and the final fracture zones, as displayed in Photograph No. 123, reveals a nondescript, featureless fracture surface. The fracture location labeled as Location-5A was examined at higher magnification to characterize the fracture morphology.



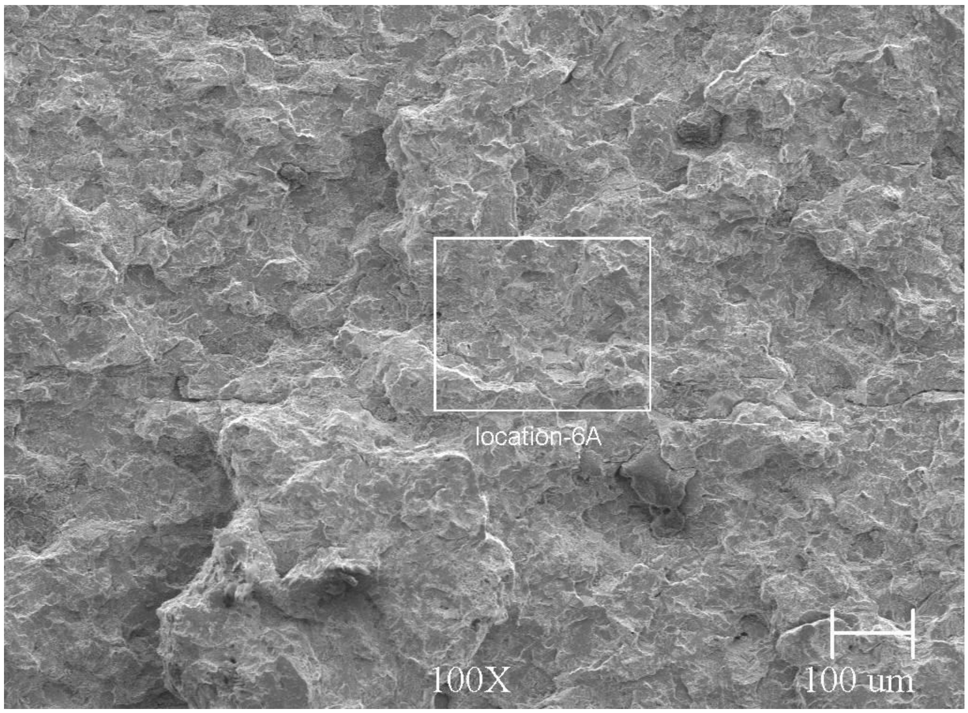
Area-E, Location-5A
Photograph No. 137

The SEM fractograph taken of the Area-E at Location-5A displays some evidence of oxidation product in the hook crack and evidence of quasi-cleavage separation in the final fracture zone, indicative of pre-existing crack and final brittle fracture, respectively.



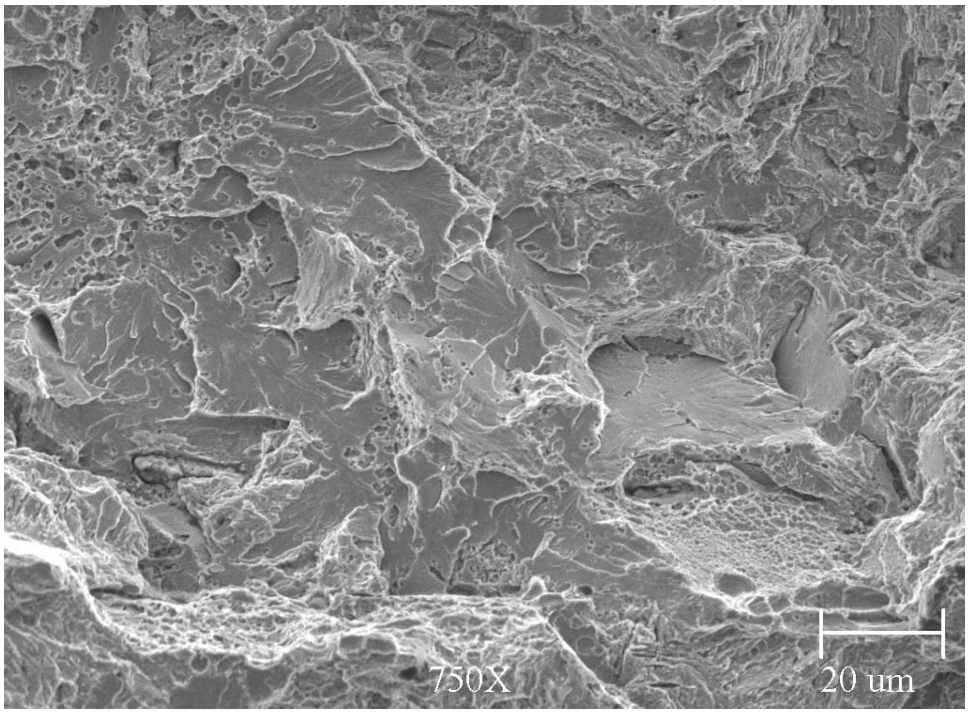
Area-E, Location-5A, Location within rectangle
Photograph No. 138

The SEM fractograph taken of the Area-E at Location-5A, as displayed in Photograph No. 137, confirms the oxidation on the hook cracks and the final fracture in the brittle manner.



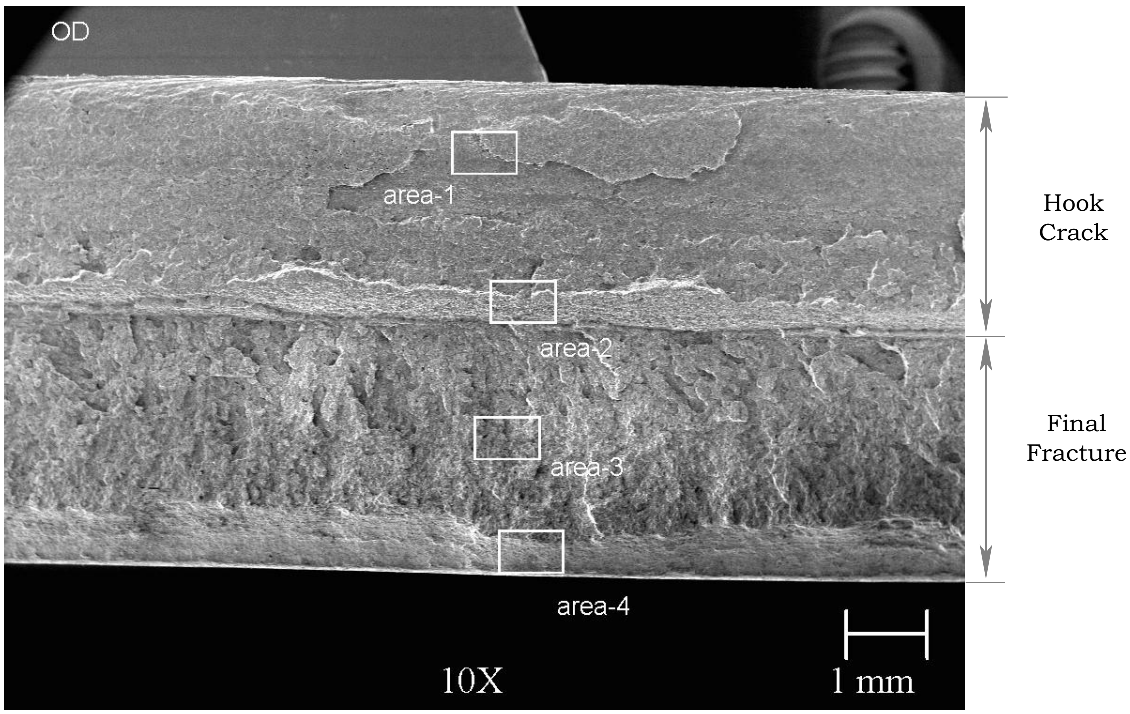
Area-F
Photograph No. 139

The SEM fractograph taken of the Area-F of the final fracture zone, as shown in Photograph No. 123, displays unresolved cleavage separation fracture features and faint evidence of ductile microvoid coalescence.



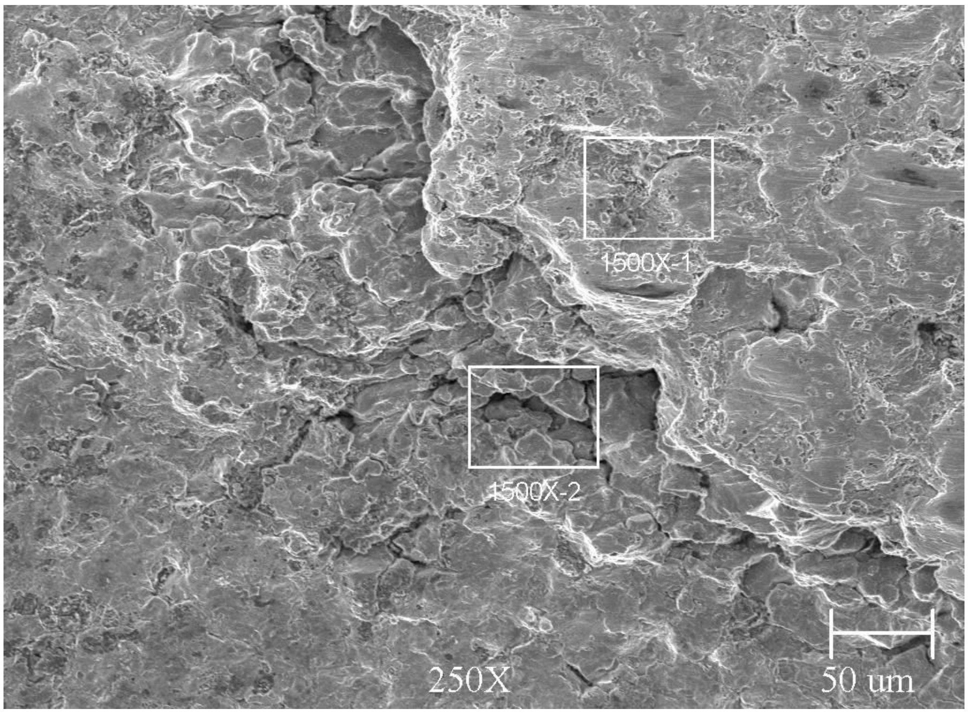
Area-F, Location-6A
Photograph No. 140

The SEM fractograph taken of the Area-F at Location-6A of the final fracture zone confirm the presence of predominantly brittle failure with some isolated areas of ductile failure, as indicated by the presence of cleavage separation and patches of microvoid coalescence, respectively.



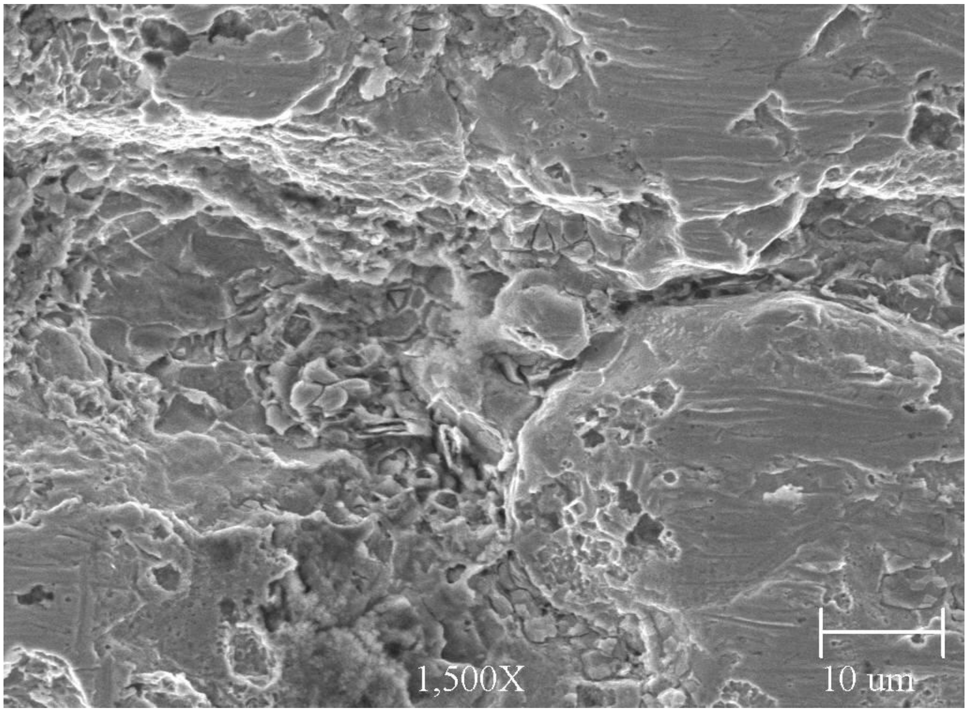
Photograph No. 141

The SEM fractograph taken of the several fracture origin sites at a distance of 20' 6-3/4" from the north girth weld shows an hook crack and the final fracture zone. The fracture areas within the rectangles were examined at higher magnifications to further characterize the fracture morphologies.

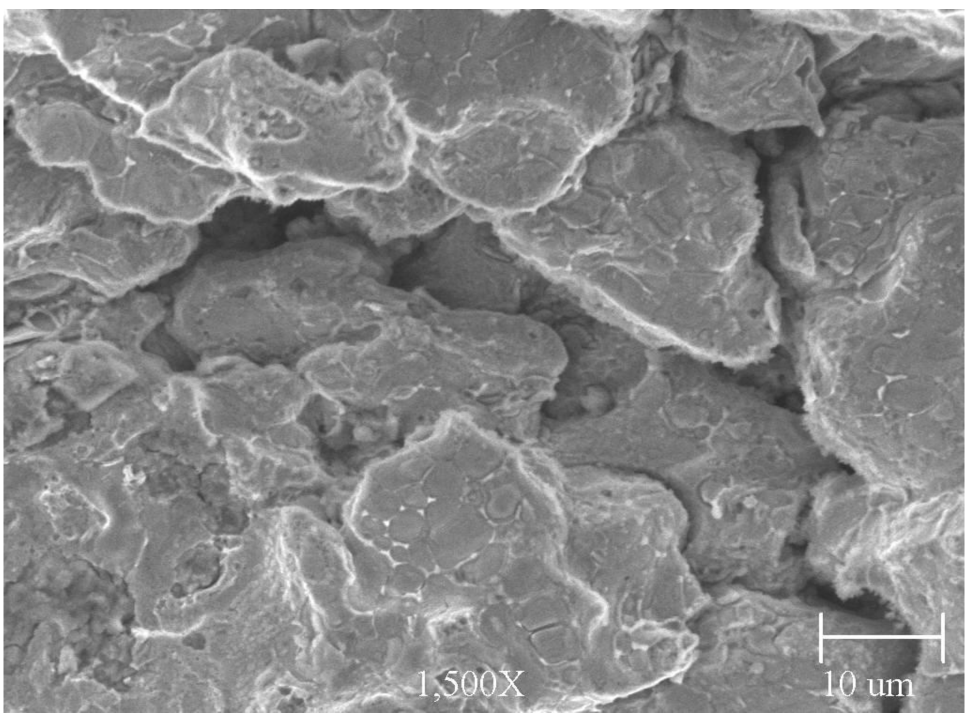


Area-1
Photograph No. 142

The SEM fractograph taken of the Area-1 of the hook crack fracture zone, as displayed in Photograph No. 141, reveals a highly oxidized fracture surface. The fracture areas, labeled as 1 and 2, were examined at higher magnification to further characterize the fracture morphologies.

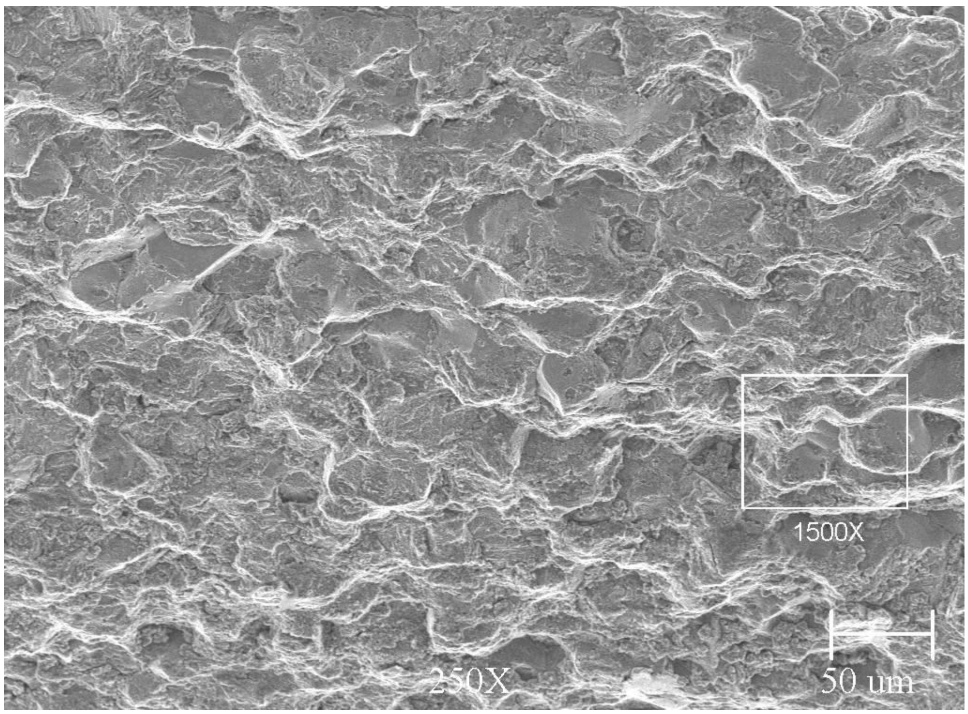


Area-1, Location-1
Photograph No. 143



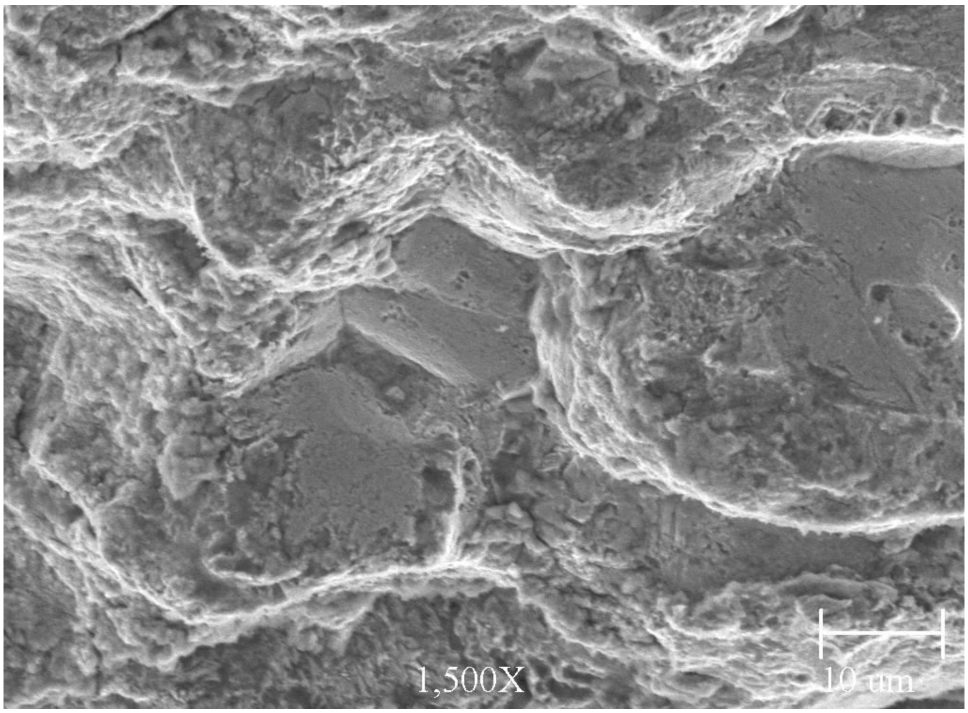
Area-1, Location-2
Photograph No. 144

The SEM fractographs taken of the fracture zones labeled as Location-1 and Location-2 in Area-1 of the hook crack reveal a highly oxidized surface and evidence of what appears to be intergranular fracture in a very small fracture zone, respectively. The intergranular fracture may have resulted along the ferrite grain boundaries.



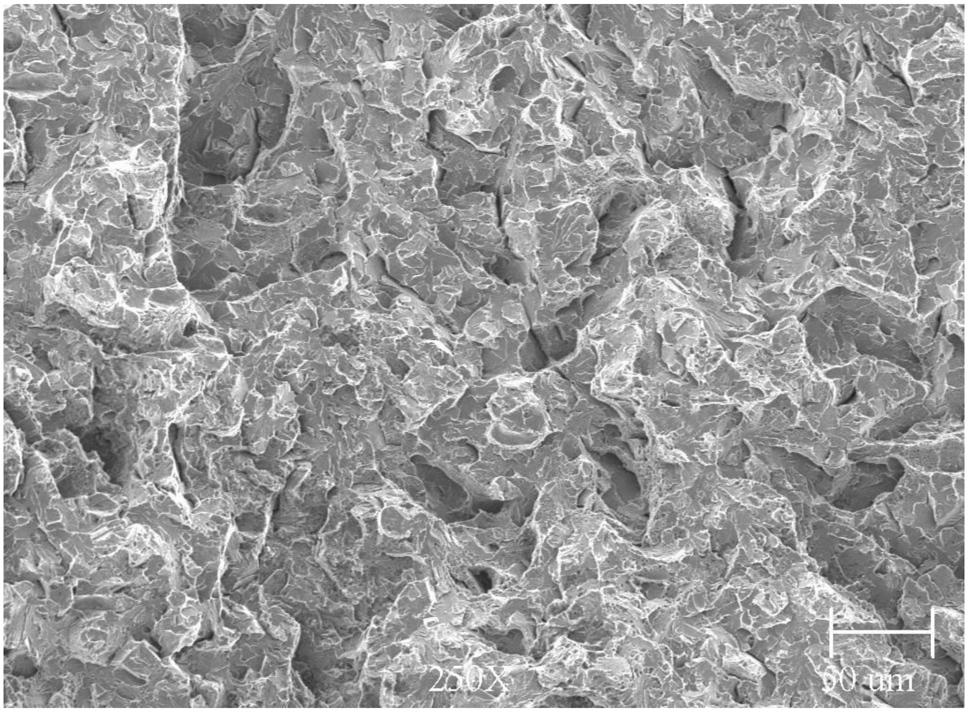
Area-2
Photograph No. 145

The SEM fractograph taken of the Area-2 of the hook crack, as displayed in Photograph No. 141, reveals the tightly adhered oxidation product. The area within the rectangle was examined at higher magnification to further characterize the fracture morphology.

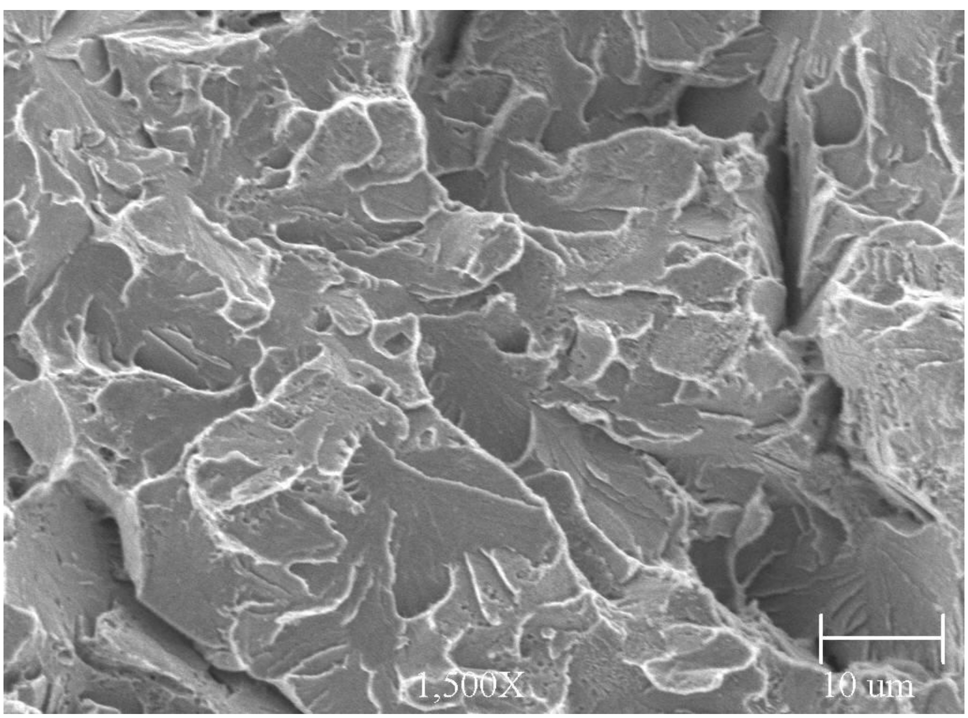


Area-2, within the rectangle
Photograph No. 146

The SEM fractograph taken of the Area-2 within the rectangle in the hook crack, as displayed in Photograph No. 145, reveals a nondescript, featureless fracture surface covered with tightly adhered oxidation product.

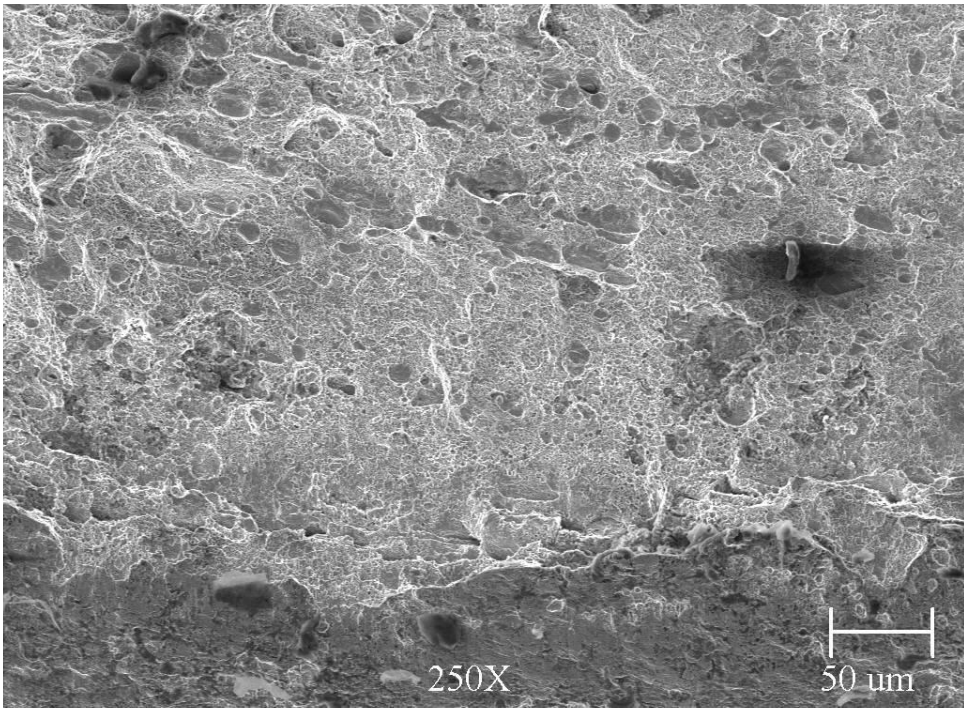


Area-3
Photograph No. 147

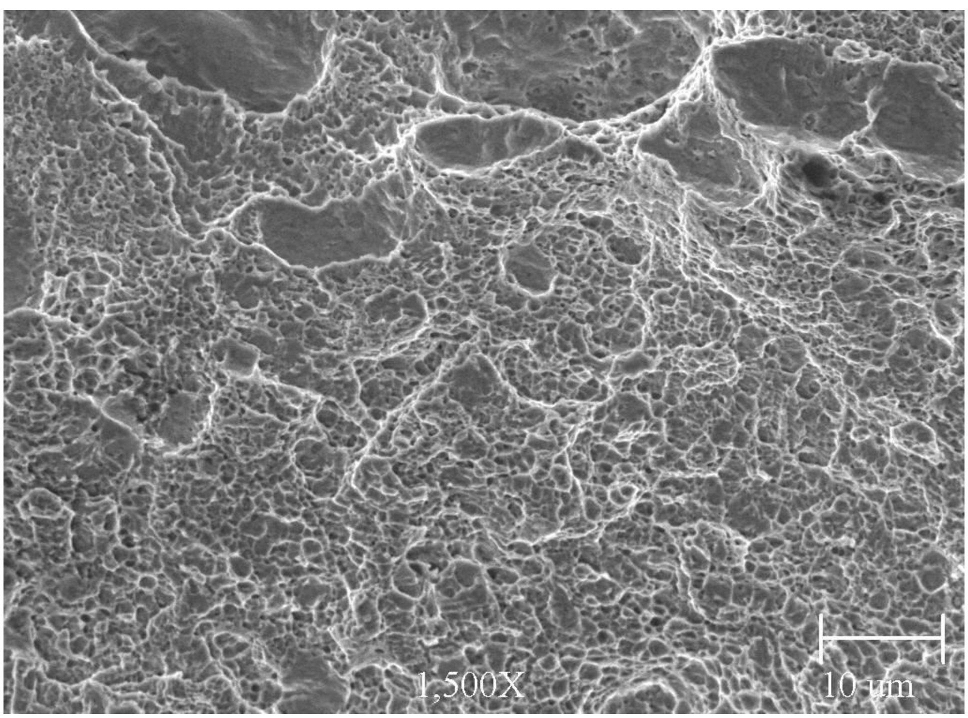


Area-3
Photograph No. 148

The SEM fractographs taken of the Area-3 of the final fracture zone, as displayed in Photograph No. 141, reveal cleavage separation, indicative of brittle failure.

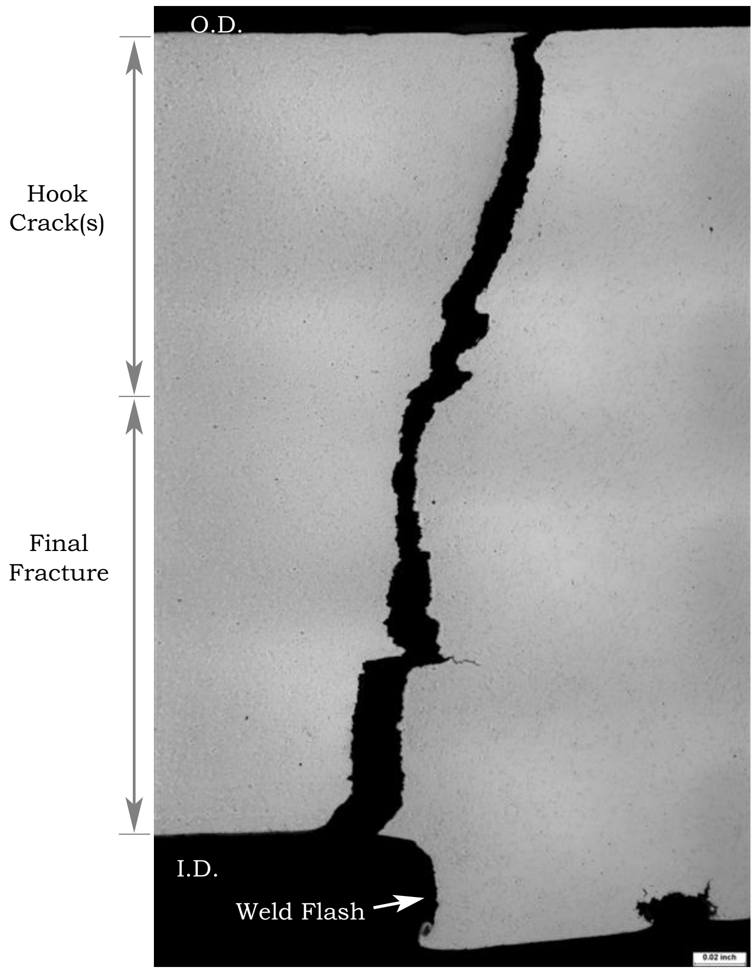


Area-4
Photograph No. 149



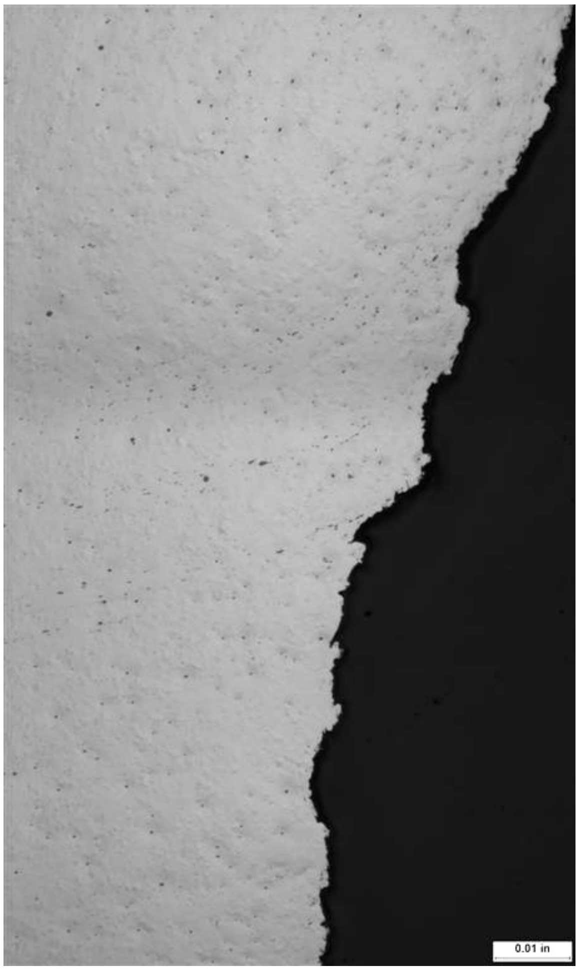
Area-4
Photograph No. 150

The SEM fractographs taken of the Area-4 of the final shear fracture zone at the I.D. of the pipe reveal evidence of microvoid coalescence, indicative of rapid ductile failure.

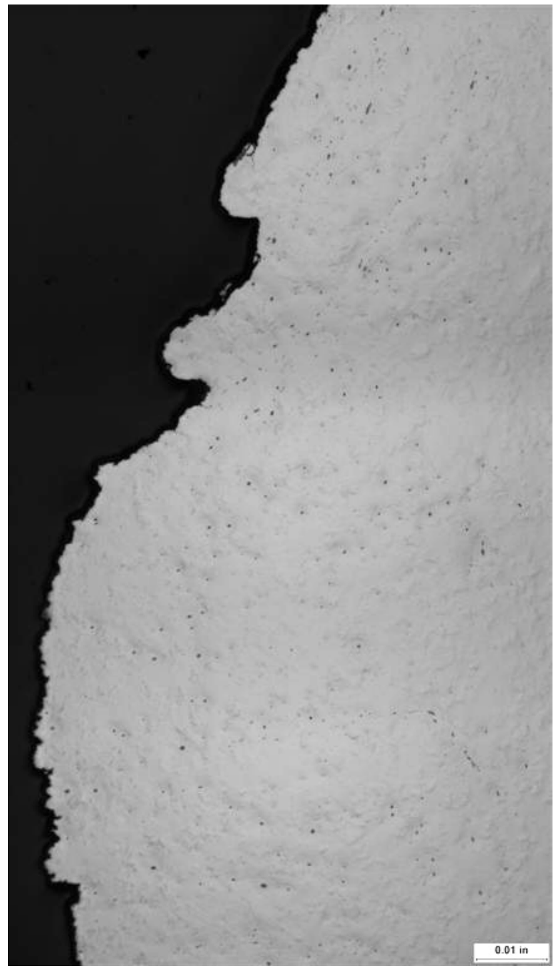


20' 4-7/8" from the North Girth Weld
As-polished, ~25x
Photograph No. 151

A composite view of the mating cross-sections removed through the fracture origins area at a distance of 20' 4-7/8" from the north girth weld and prepared for metallographic examination displays evidence of nonmetallic inclusions along the fracture faces and also parallel to the fusion line near the upper half of the pipe wall. Note that the weld flash on the I.D. surface of the pipe was not trimmed off flush with the I.D. surface.

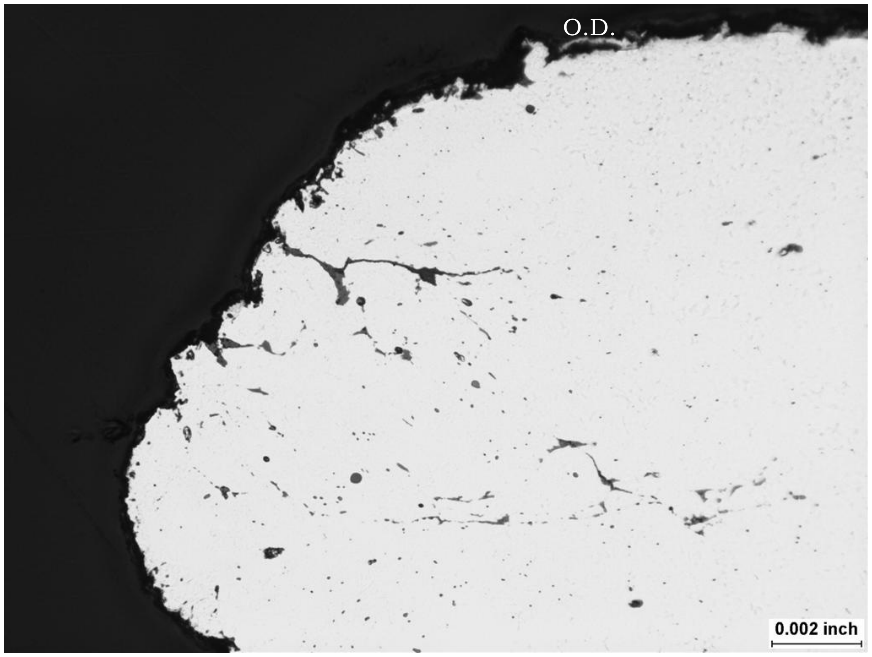


20' 4-7/8" from the North Girth Weld
As-polished, ~50x
Photograph No. 152

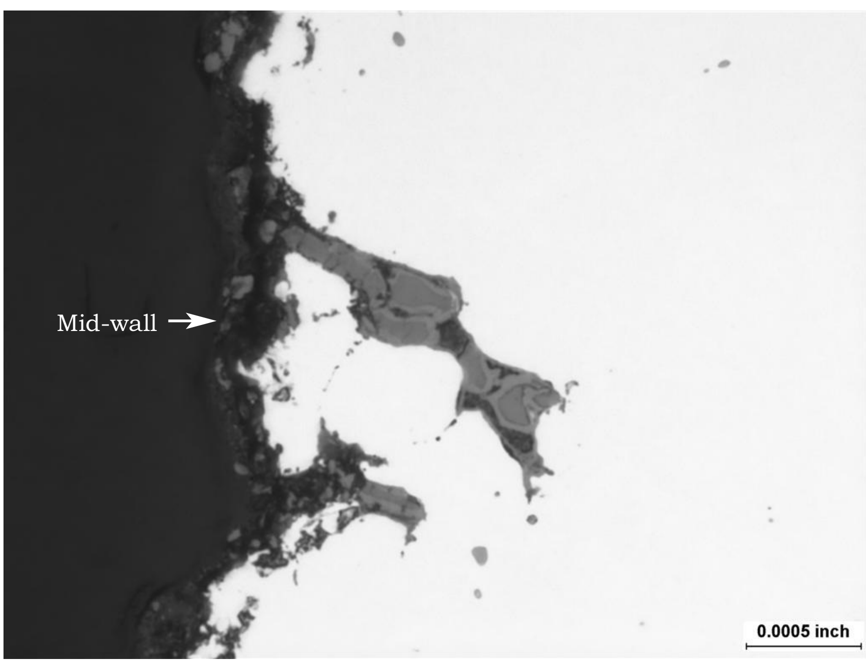


20' 4-7/8" from the North Girth Weld
As-polished, ~50x
Photograph No. 153

The micrographs display the upturned inclusions essentially parallel to the fusion line in the ERW upset/HAZ area, as well as along the fracture faces. Note that vertically aligned inclusions are one of the main contributing factors to the formation of hook cracks.

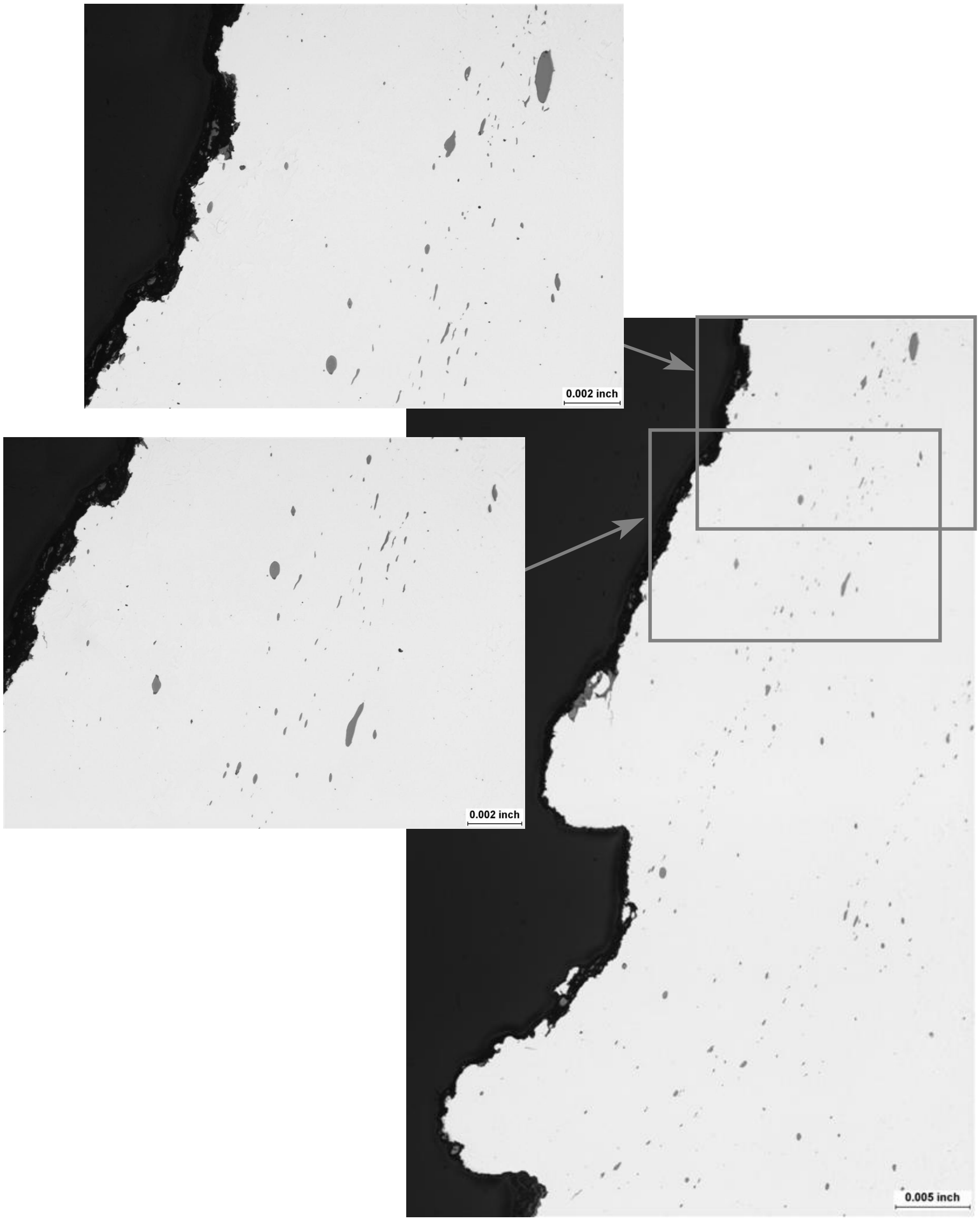


20' 4-7/8" from the North Girth Weld
As-polished, ~200x
Photograph No. 154



20' 4-7/8" from the North Girth Weld
As-polished, ~1000x
Photograph No. 155

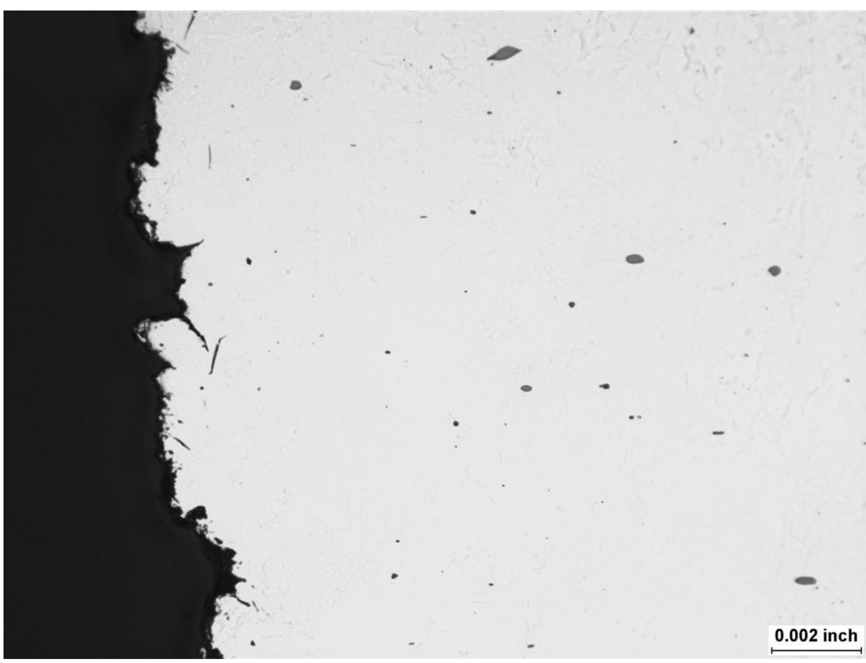
The micrographs display evidence of folds at the O.D. surface at the fusion line, which was apparently not fully fused, and the presence of post-fracture oxidation at the mid-wall area along the hook crack fracture face.



20' 4-7/8" from the North Girth Weld
As-polished, ~100x
Photograph No. 156

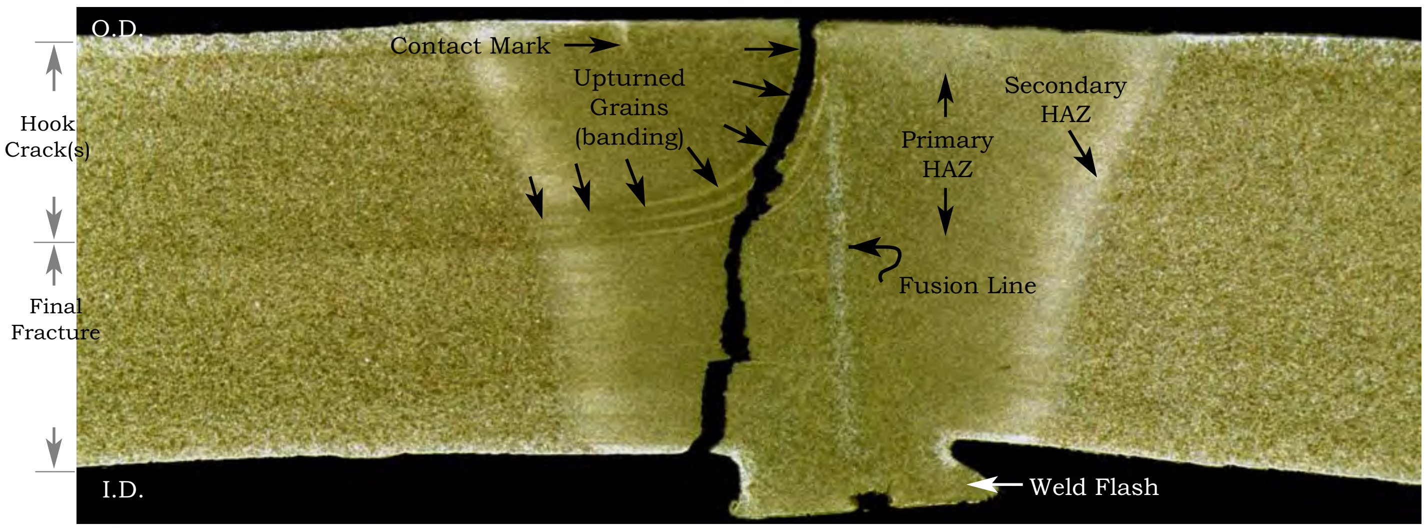
The micrographs display an excessive amount of elongated manganese sulfide inclusions in the diagonal and vertical planes in the upset/HAZ area of the ERW seam. Note the hook crack along and through the realigned inclusions.

20' 4-7/8" from the North Girth Weld
As-polished, ~200x
Photograph No. 157



20' 4-7/8" from the North Girth Weld
As-polished, ~200x
Photograph No. 158

The micrographs display the manganese sulfide inclusions in the axial direction of the pipe near the I.D. surface of the ERW, which were not affected by the welding process.

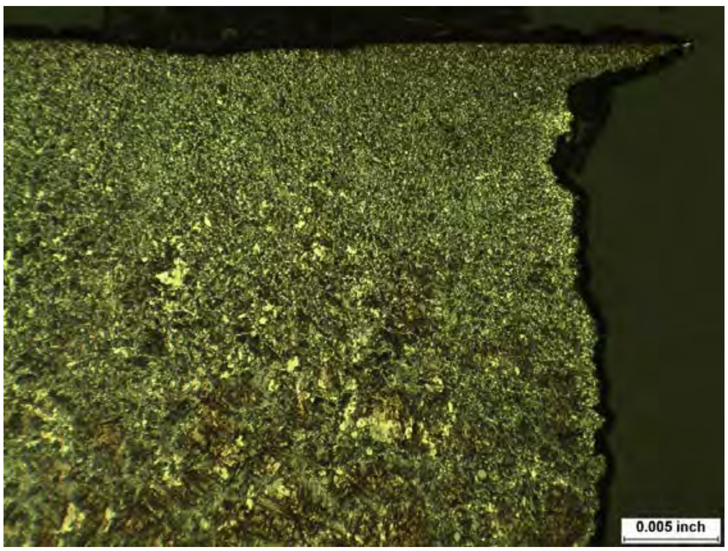


20' 4-7/8" from the North Girth Weld
2% Nital etch, ~20x
Photograph No. 159

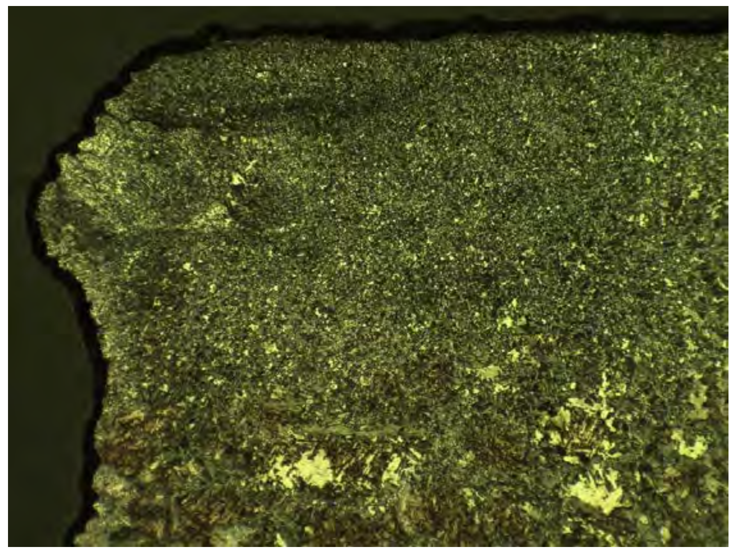
A composite view of the mating cross-sections removed through the fracture origins area at a distance of 20' 4-7/8" from the north girth weld and prepared for metallographic evaluation shows hook cracks along the brittle upturned bands in the upset/HAZ area, and the final failure from the tip(s) of the hook crack(s). Again, note that the weld flash was not trimmed off flush with the I.D. surface.

20' 4-7/8" from the North Girth Weld
2% Nital etch, ~25x
Photograph No. 160

The micrograph displays a hook crack through the upturned bands, which consists of untempered brittle martensite in the upset/HAZ of the ERW seam.

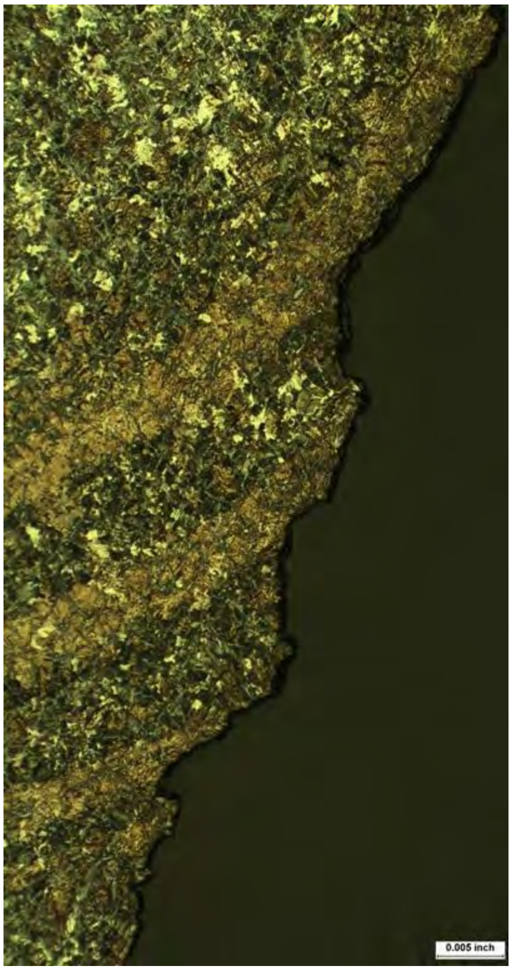


20' 4-7/8" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 161



20' 4-7/8" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 162

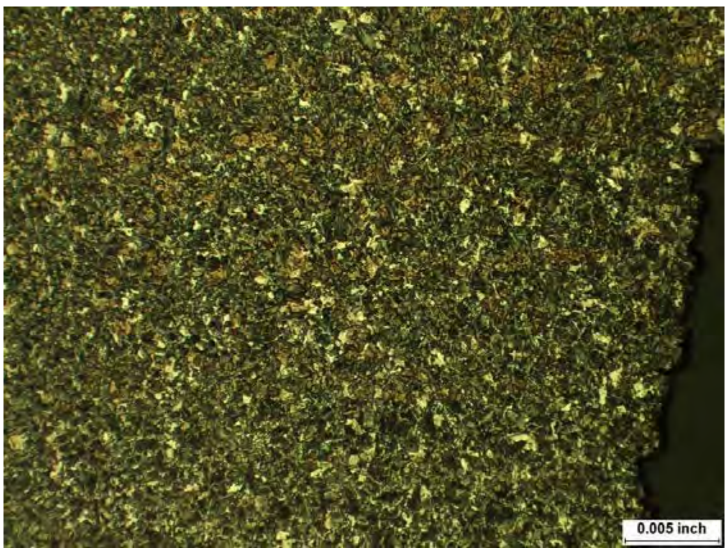
The micrographs display the mating fracture faces of hook cracks near the O.D. of the ERW joint. The microstructure consists of grain boundary ferrite and unresolved bainite with some acicular martensite.



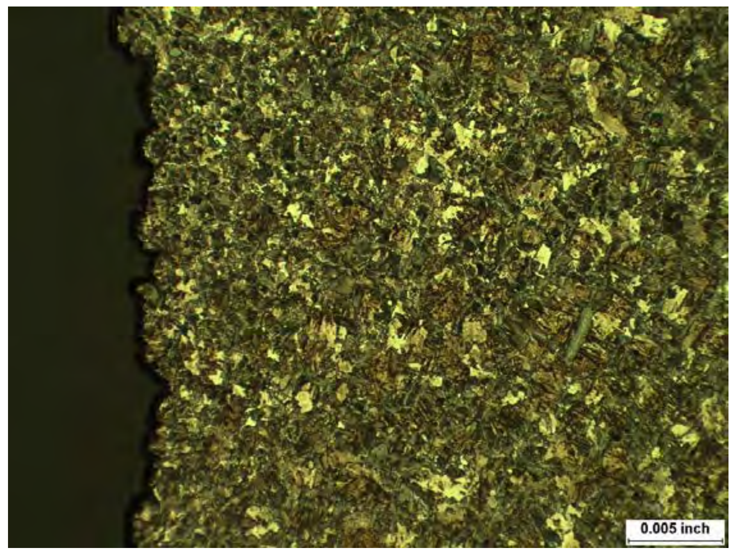
20' 4-7/8" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 163

20' 4-7/8" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 164

The micrographs display the mating fracture faces of the hook cracks near the mid-wall of the ERW joint. Note the presence of mix-microstructure in the upset/HAZ of the ERW seam. The upturned bands consist of essentially untempered brittle martensite and the matrix outside of the bands consists of ferrite and unresolved bainite.

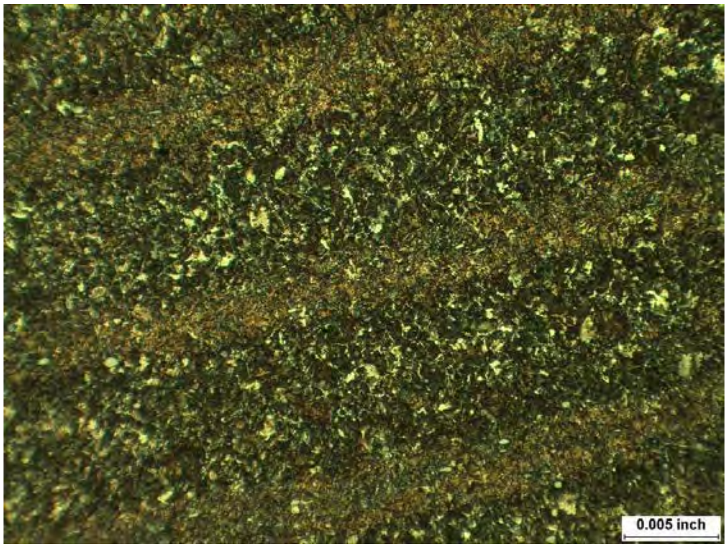


20' 4-7/8" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 165

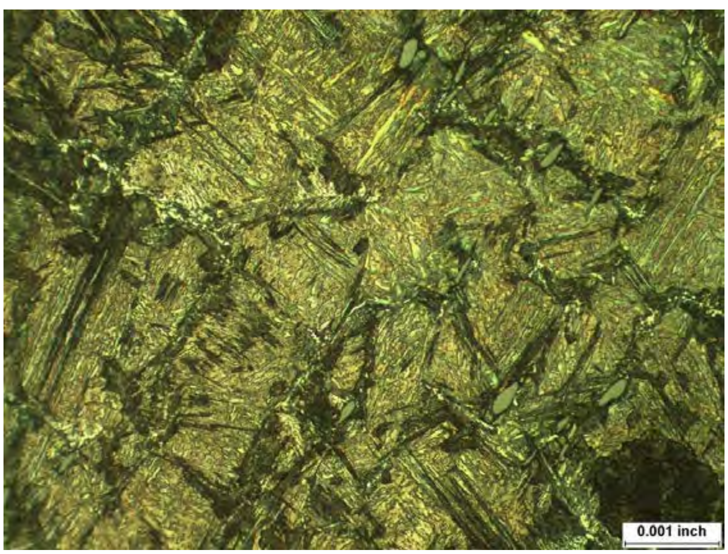


20' 4-7/8" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 166

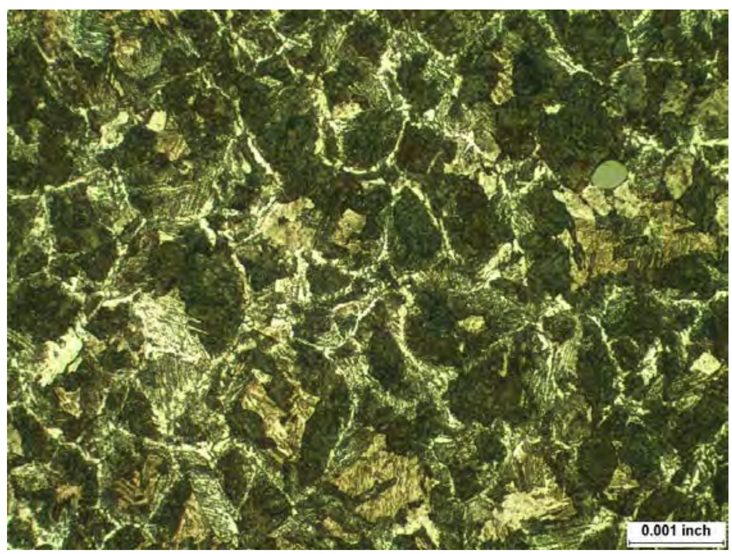
The micrographs display the mating fracture faces of the final crack near the I.D. of the ERW joint. Note the presence of mix-microstructure in the HAZ of the ERW seam consisting of patches of untempered acicular martensite, grain boundary ferrite, and unresolved bainite.



20' 4-7/8" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 167

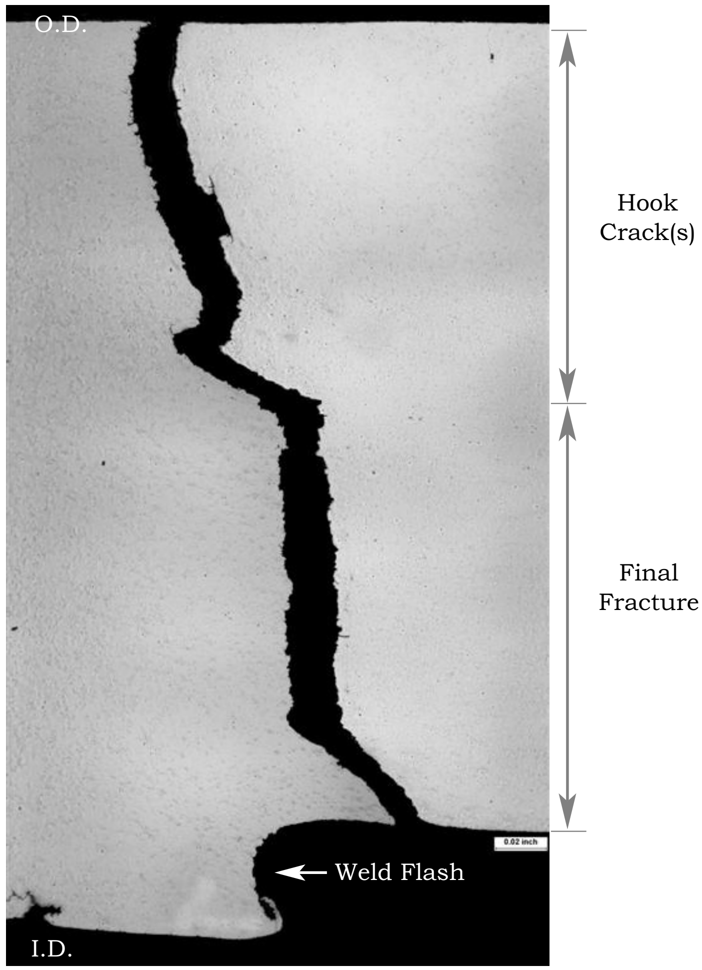


20' 4-7/8" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 168



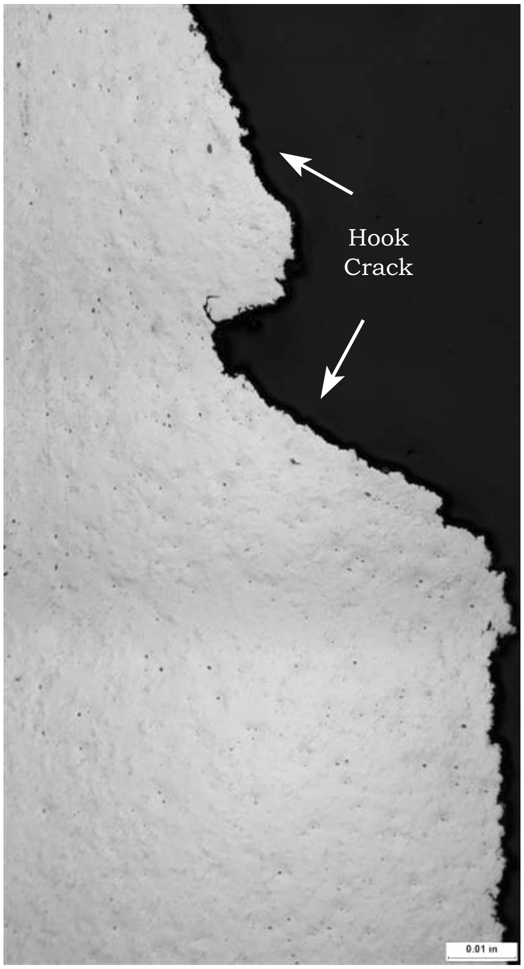
20' 4-7/8" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 169

The micrographs display the microstructure of the material in the upset/HAZ between the O.D. and the mid-wall where the upturned bands were formed during the ERW seam manufacturing, consisting of the untempered brittle martensite in the banded area and essentially grain boundary ferrite and unresolved bainite with some patches of untempered martensite in the non-banded area.

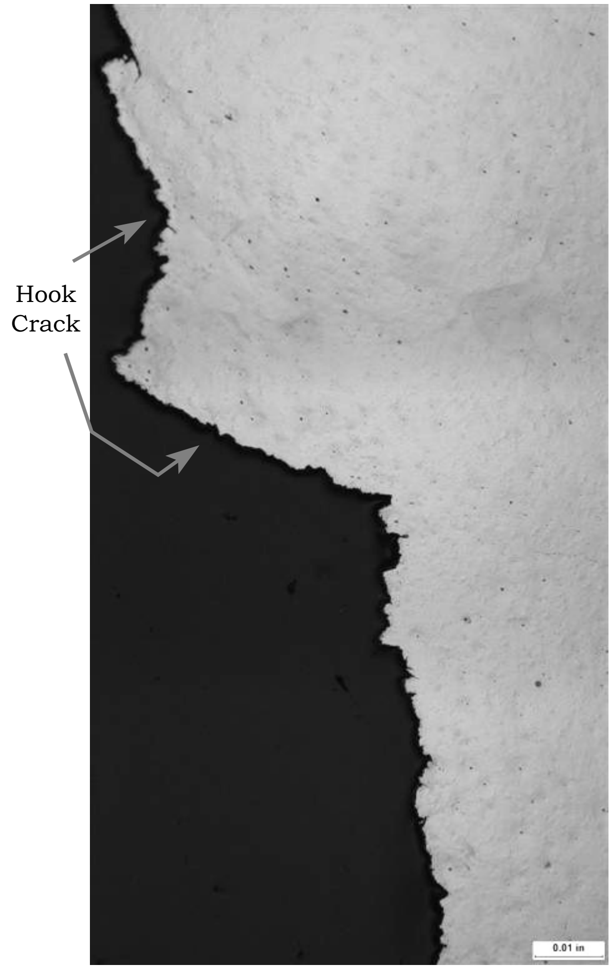


20' 6-13/16" from the North Girth Weld
As-polished, ~25x
Photograph No. 170

A composite view of the mating cross-sections removed through the fracture origins area at a distance of 20' 6-13/16" from the north girth weld and prepared for metallographic examination displays evidence of nonmetallic inclusions along the fracture faces, and also parallel to the fusion line near the upper half of the pipe wall. Note that the weld flash on the I.D. surface was not trimmed off flush with the I.D. surface of the pipe.

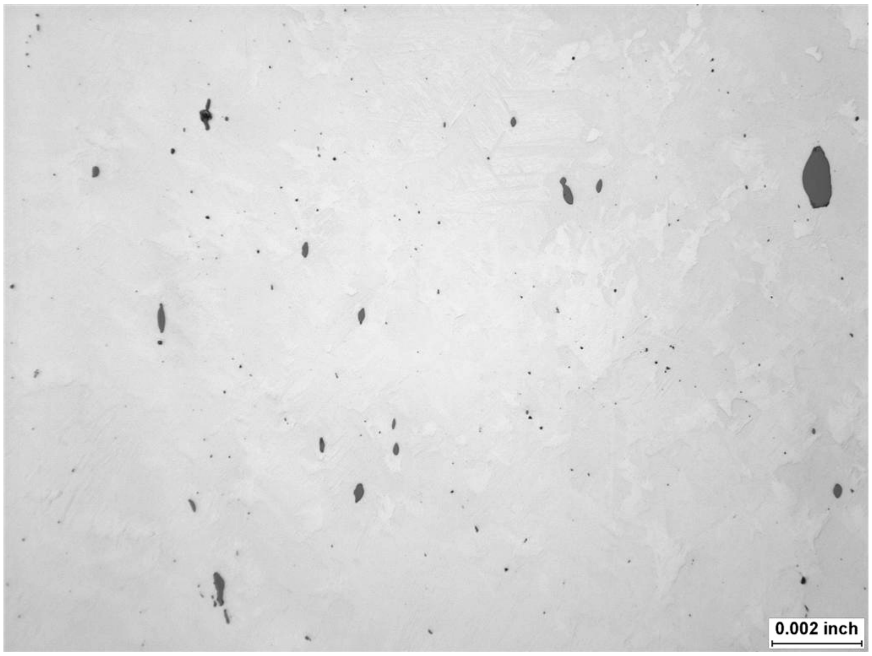


20' 6-13/16" from the North Girth Weld
As-polished, ~50x
Photograph No. 171

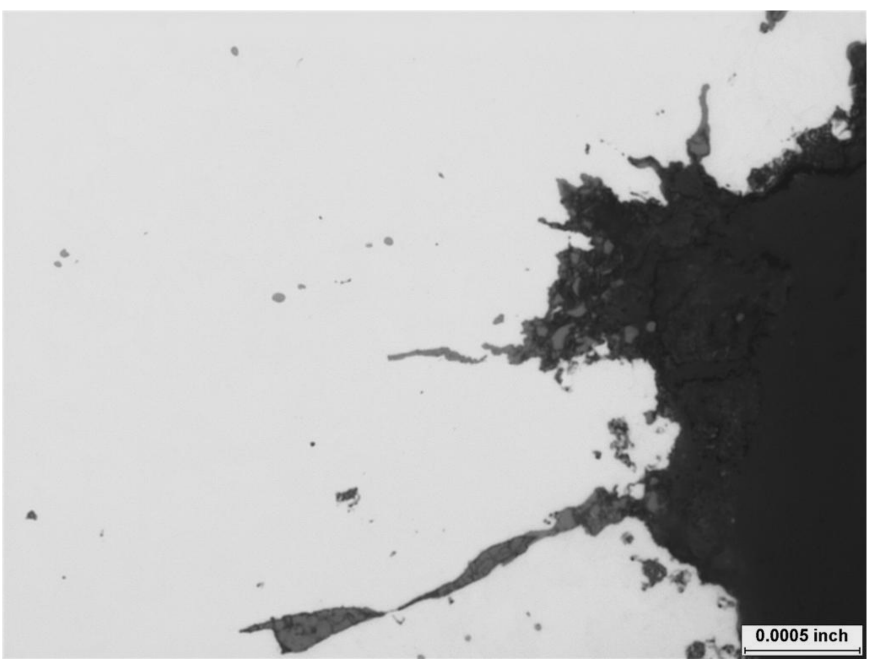


20' 6-13/16" from the North Girth Weld
As-polished, ~50x
Photograph No. 172

The micrographs display the upturned inclusions essentially parallel to the fusion line in the ERW upset/HAZ area, as well as along the fracture faces.

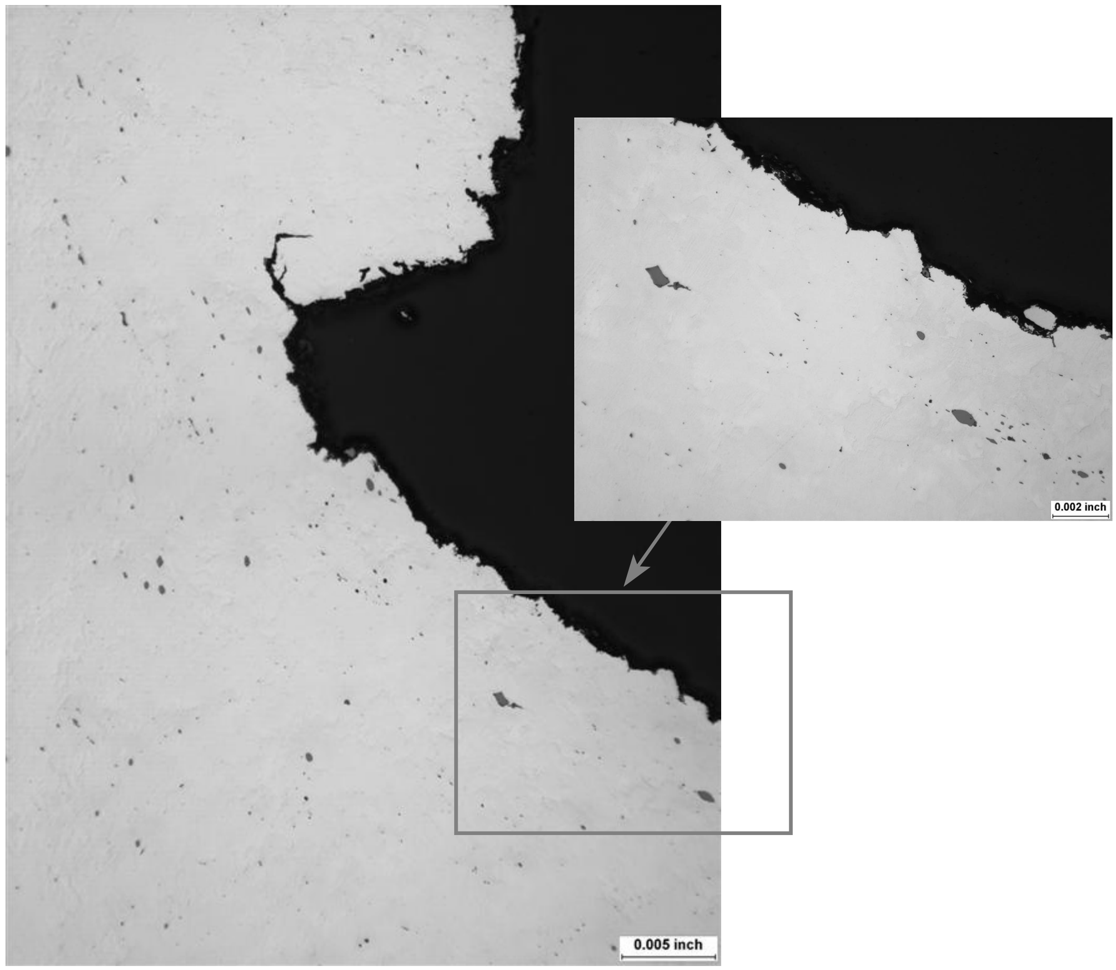


20' 6-13/16" from the North Girth Weld
As-polished, ~200x
Photograph No. 173



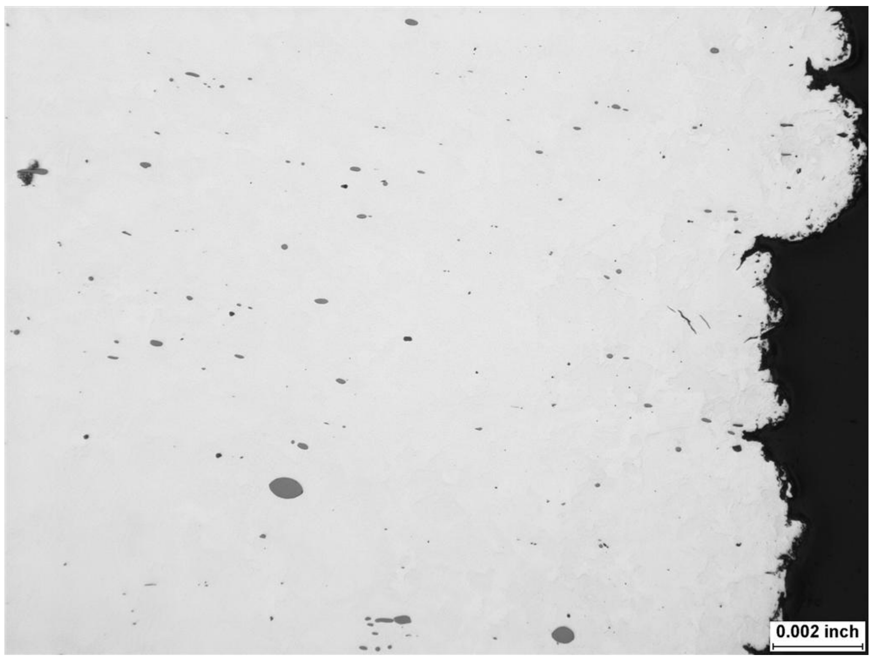
20' 6-13/16" from the North Girth Weld
As-polished, ~1000x
Photograph No. 174

The micrographs display the presence of several manganese sulfide inclusions aligned parallel to the fusion line and evidence of some post-hook crack oxidation along the fracture face near the mid-wall.



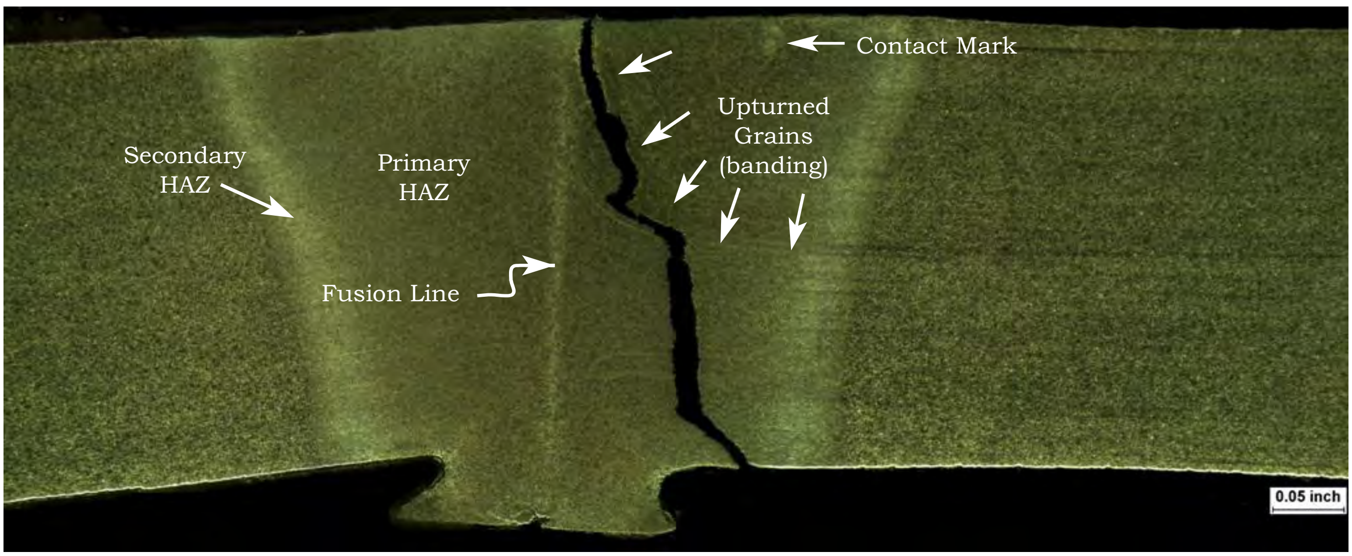
20' 6-13/16" from the North Girth Weld
As-polished, ~100x
Photograph No. 175

The micrographs display an excessive amount of elongated manganese sulfide inclusions aligned in the diagonal and vertical planes in the upset/HAZ area of the ERW seam. Note the hook crack(s) along and through the realigned inclusions.



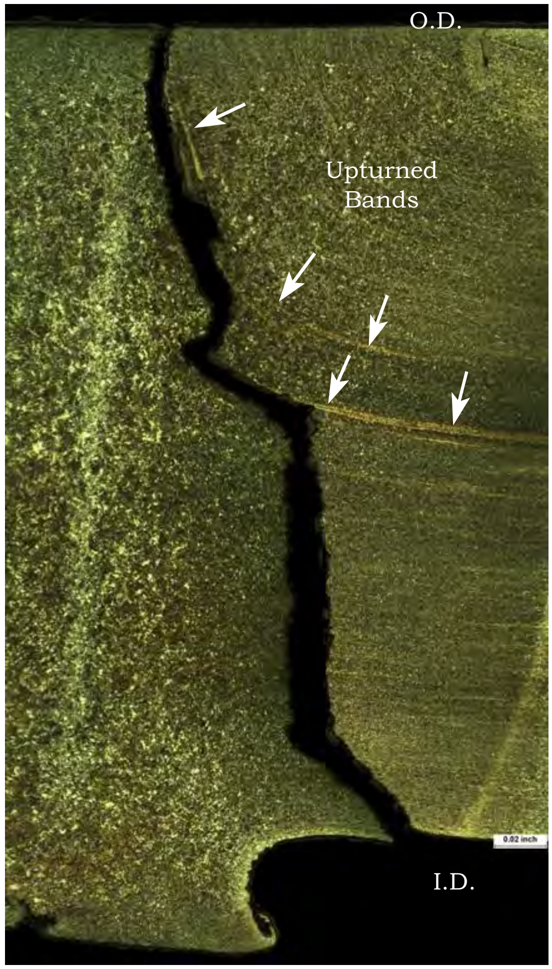
20' 6-13/16" from the North Girth Weld
As-polished, ~200x
Photograph No. 176

The micrograph displays the manganese sulfide inclusions in the axial direction of the pipe near the I.D. surface of the ERW, which were not affected by the welding process.



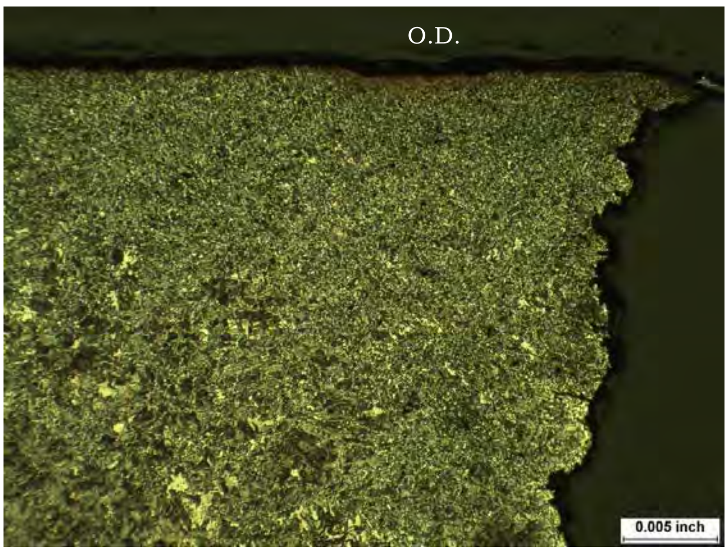
20' 6-13/16" from the North Girth Weld
2% Nital etch, ~20x
Photograph No. 177

The composite view of the mating cross-sections removed through the fracture origins area at a distance of 20' 6-13/16" from the north girth weld and prepared for metallographic evaluation shows hook crack(s) following the upturned grains and inclusions in the upset/HAZ area.

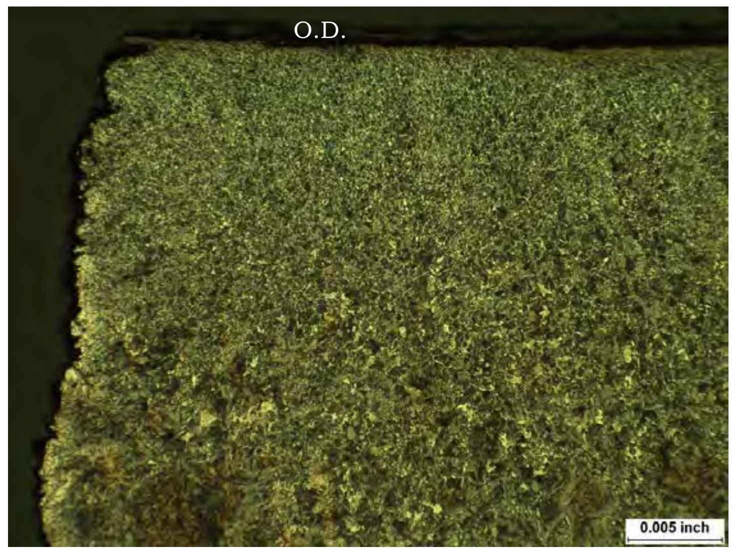


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~25x
Photograph No. 178

The micrograph displays the hook crack(s) following the upturned bands, which consists of untempered brittle martensite.

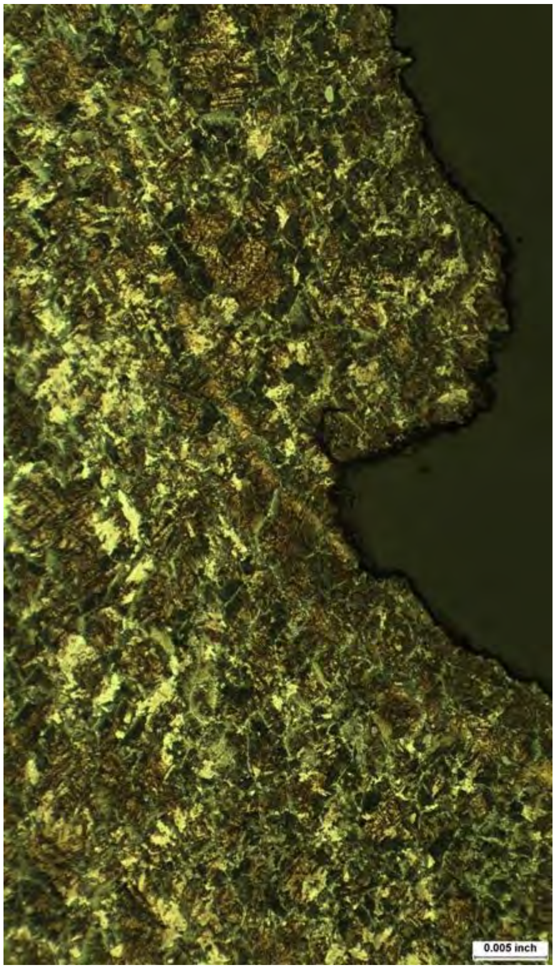


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 179

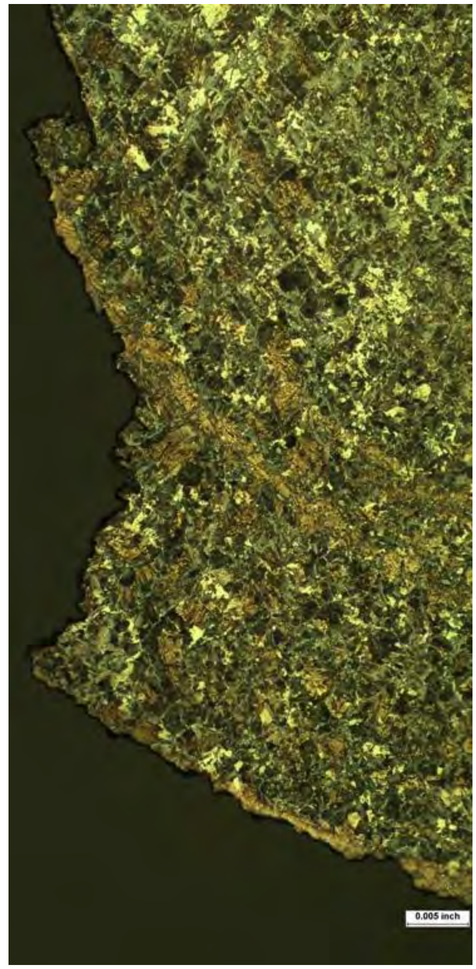


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 180

The micrographs display the mating faces of the hook crack(s) at the O.D. in the ERW seam. The microstructure consists of grain boundary ferrite and unresolved bainite with some acicular martensite.

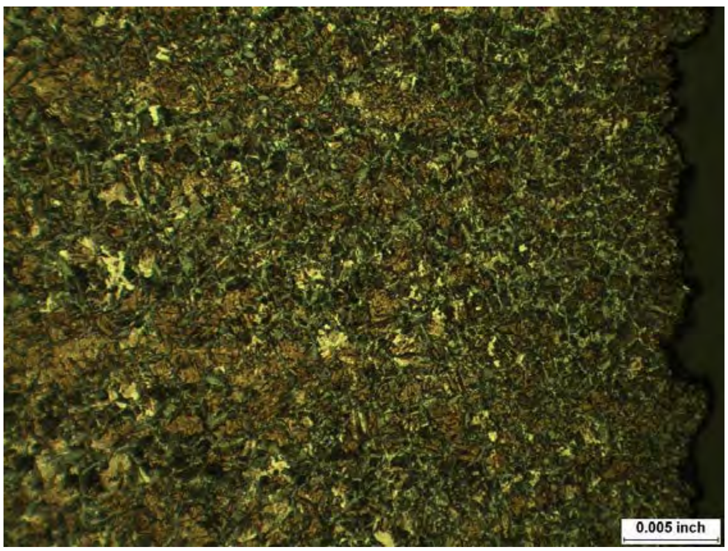


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 181

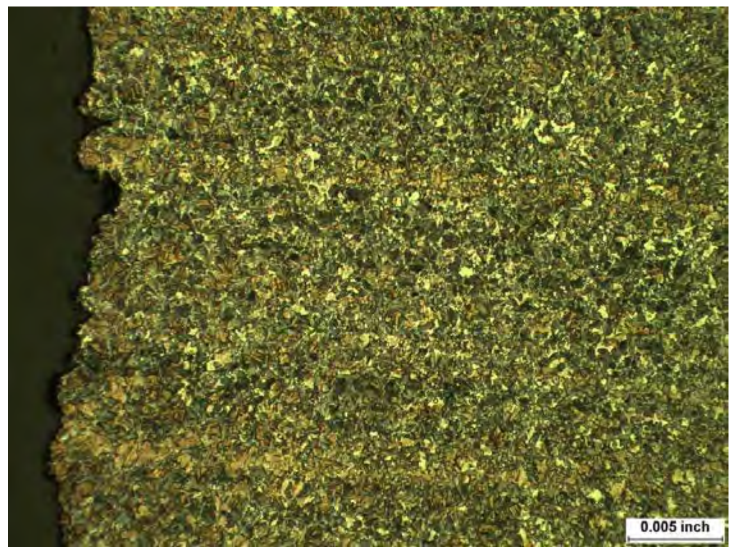


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 182

The micrographs display hook crack(s) following the upturned bands of acicular martensite and manganese sulfide inclusions.

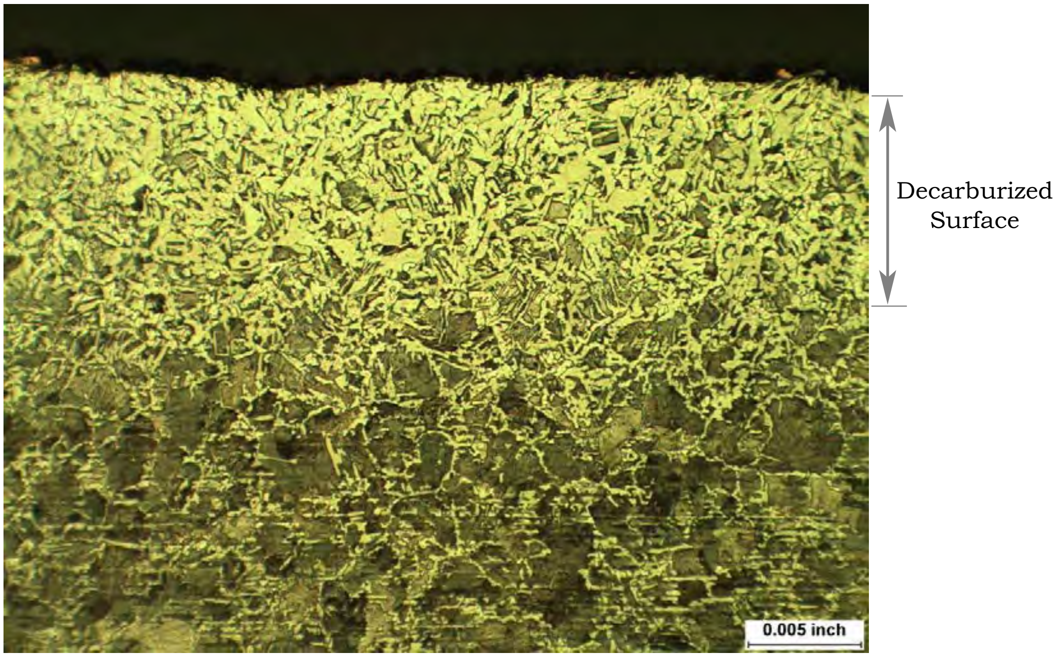


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 183

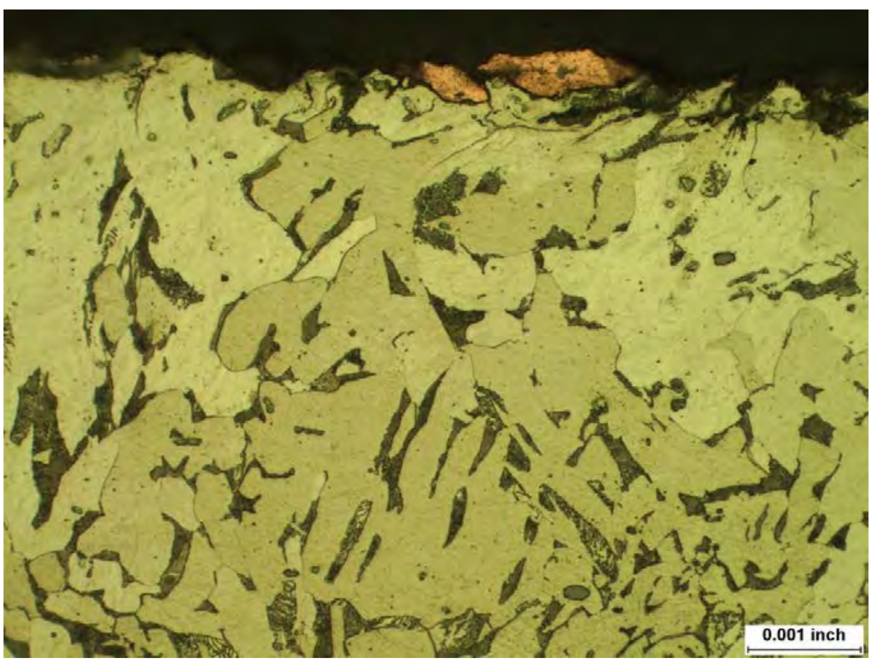


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 184

The micrographs display the mating fracture faces of the final fracture near the I.D. of the ERW joint. The microstructure consists of grain boundary ferrite, unresolved bainite, and bands of acicular untempered martensite.

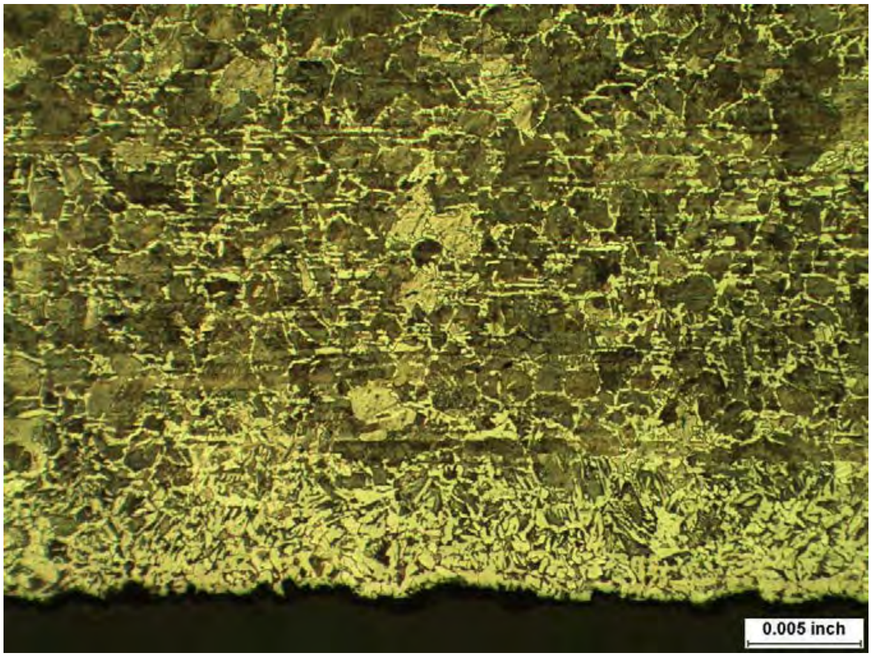


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 185

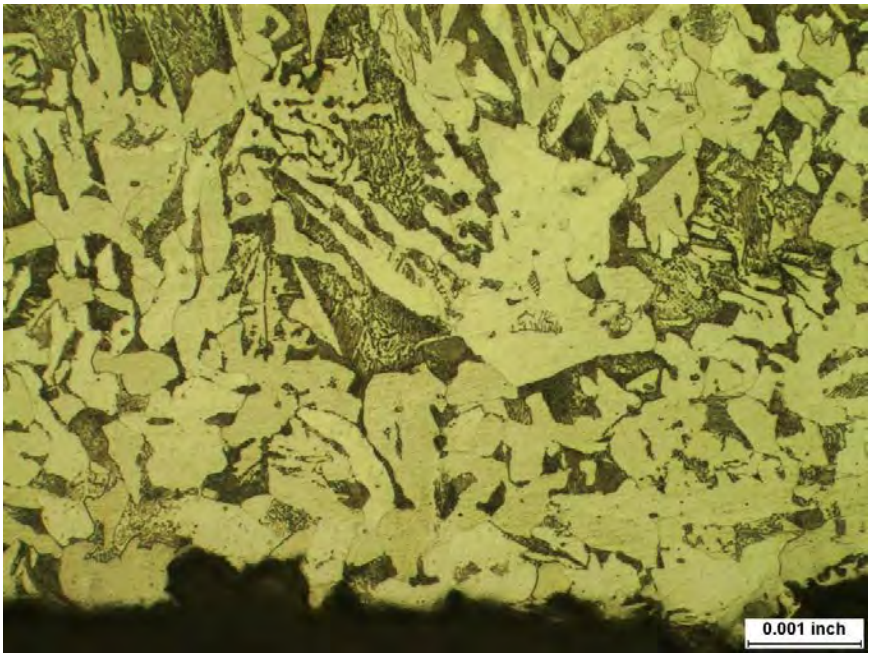


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 186

The micrographs display the evidence of surface decarburization along the O.D. surface near the ERW seam and the presence of copper from the electrode contact during the initial seam welding of the pipe.

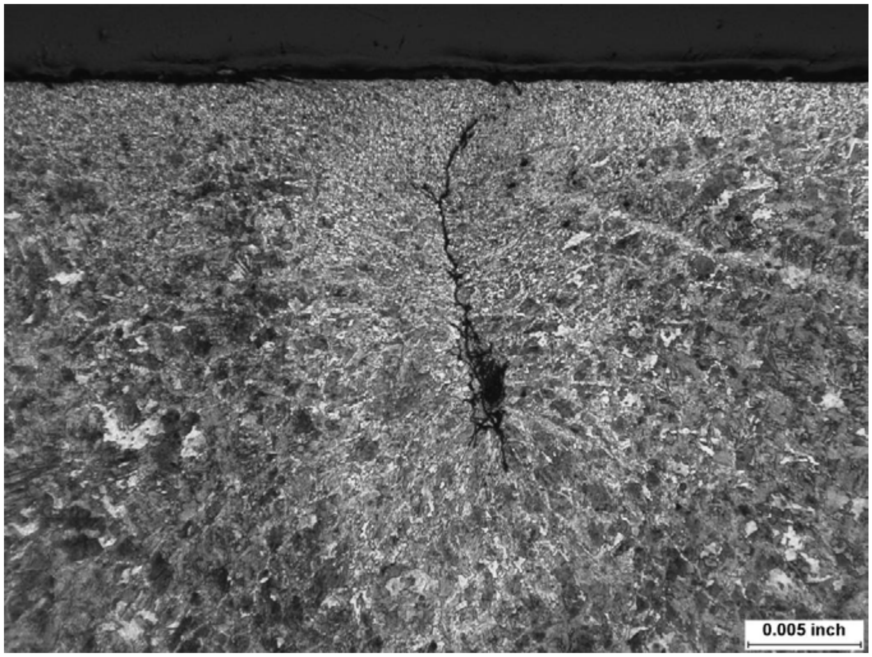


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 187

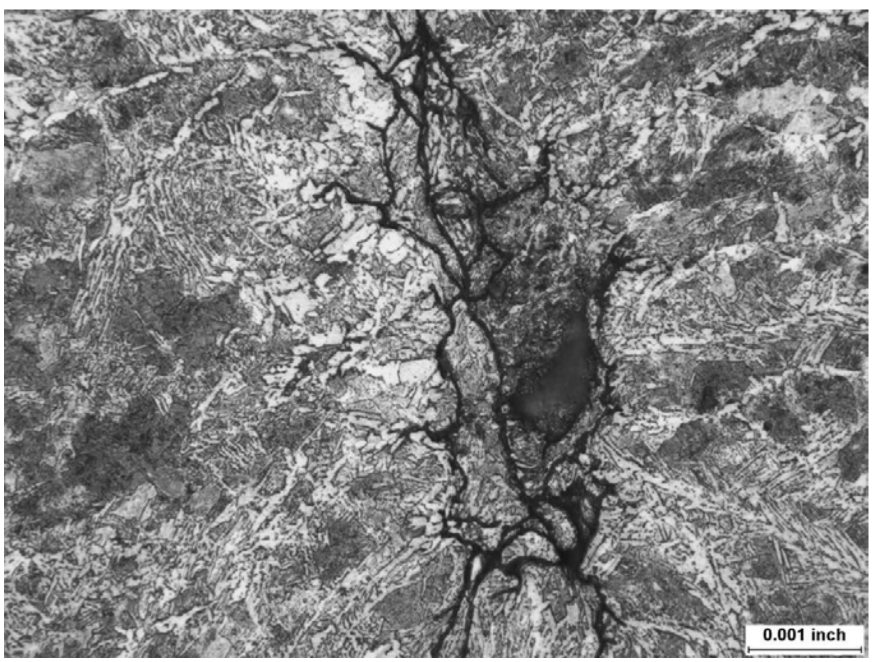


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 188

The micrographs display the evidence of surface decarburization along the I.D. surface near the ERW seam.

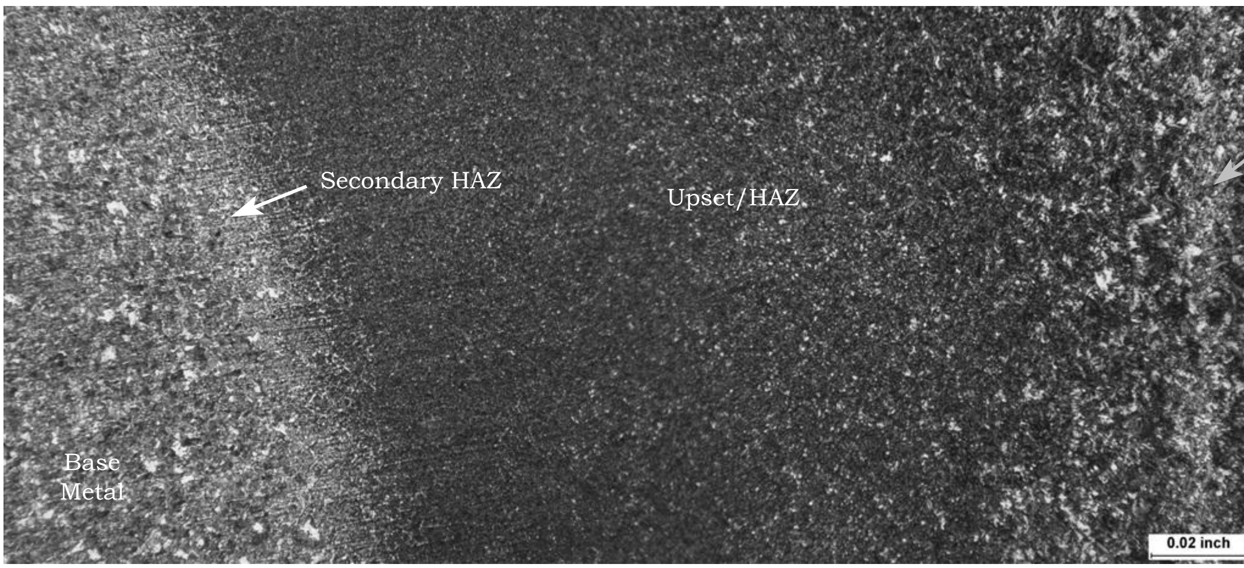


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 189



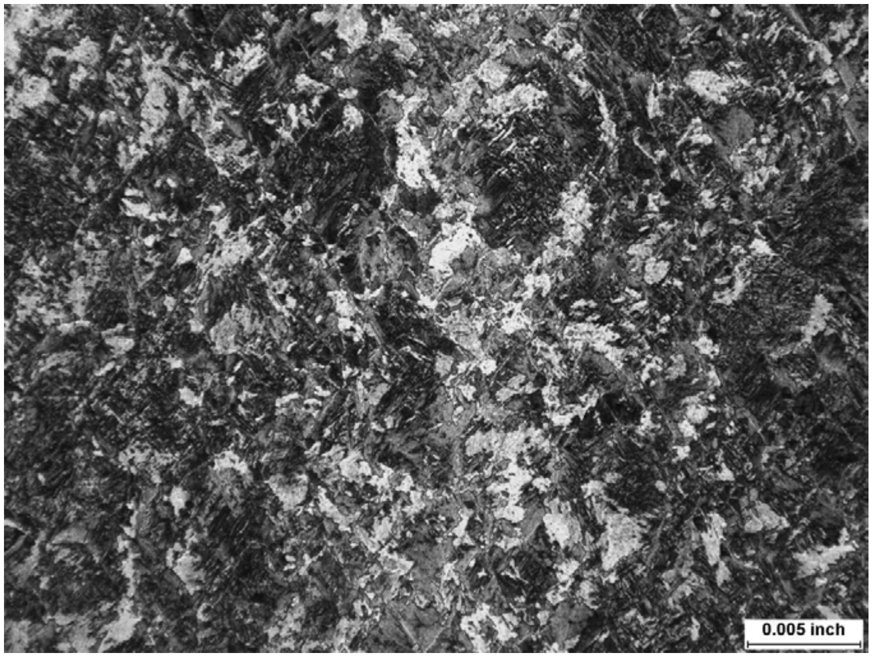
20' 6-13/16" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 190

The micrographs display one of the contact marks which resulted from the electrical contact between the electrode supplying the welding current and the pipe surface. Note cracks through resolidified metal near the ERW seam within the primary HAZ.



Fusion Line to Base Metal
2% Nital etch, ~25x
Photograph No. 191

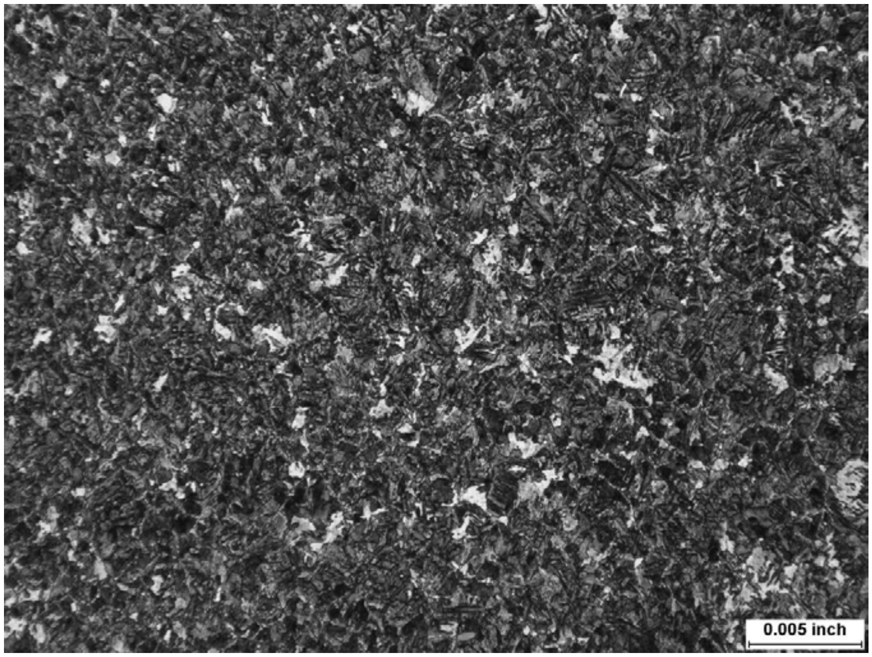
The micrograph displays the microstructural phases between the fusion line and the base metal of the ERW seam.



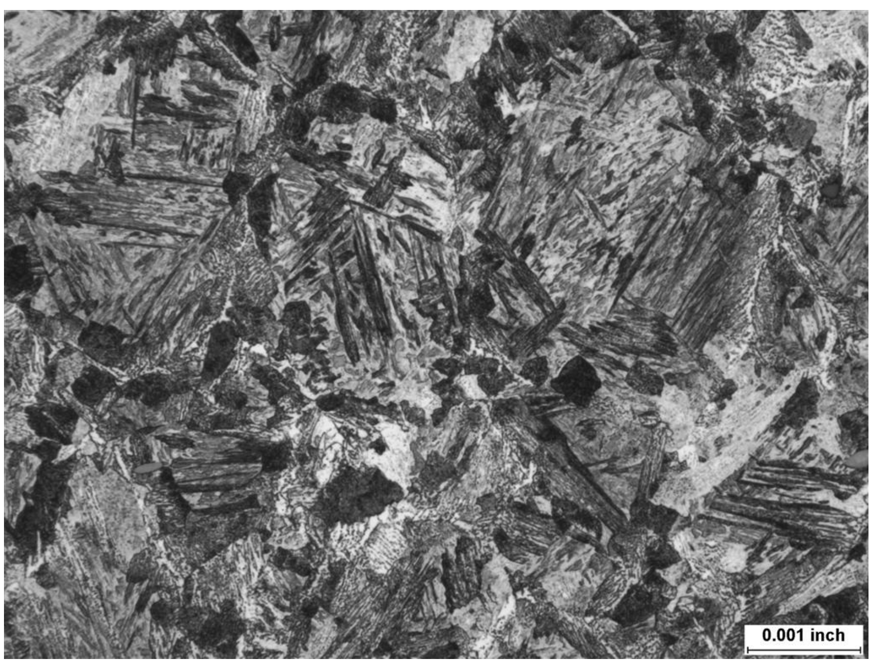
Fusion Line
2% Nital etch, ~100x
Photograph No. 192

Fusion Line
2% Nital etch, ~100x
Photograph No. 193

The micrographs display untempered bainitic/martensitic microstructure at the fusion line of the ERW seam.

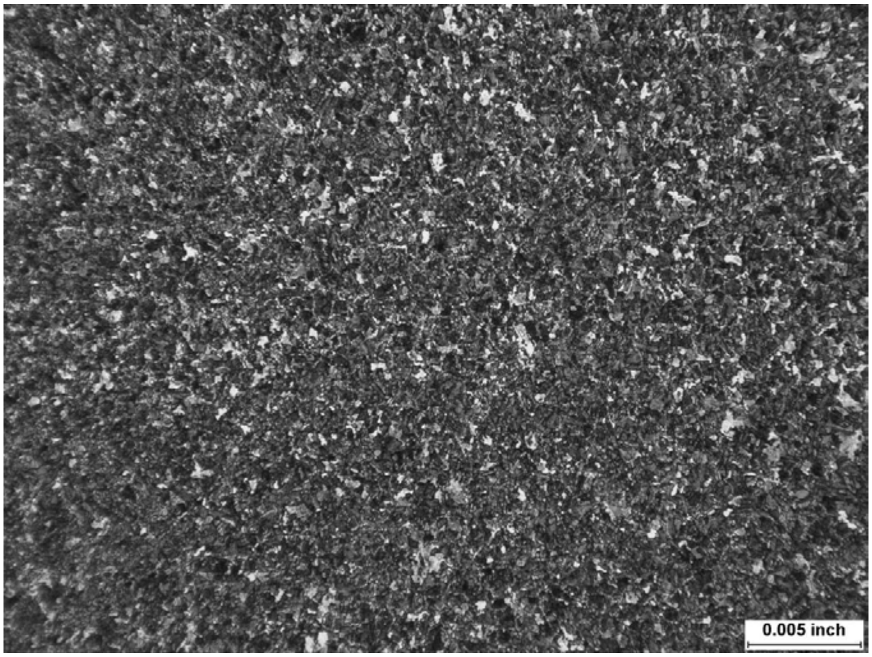


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 194

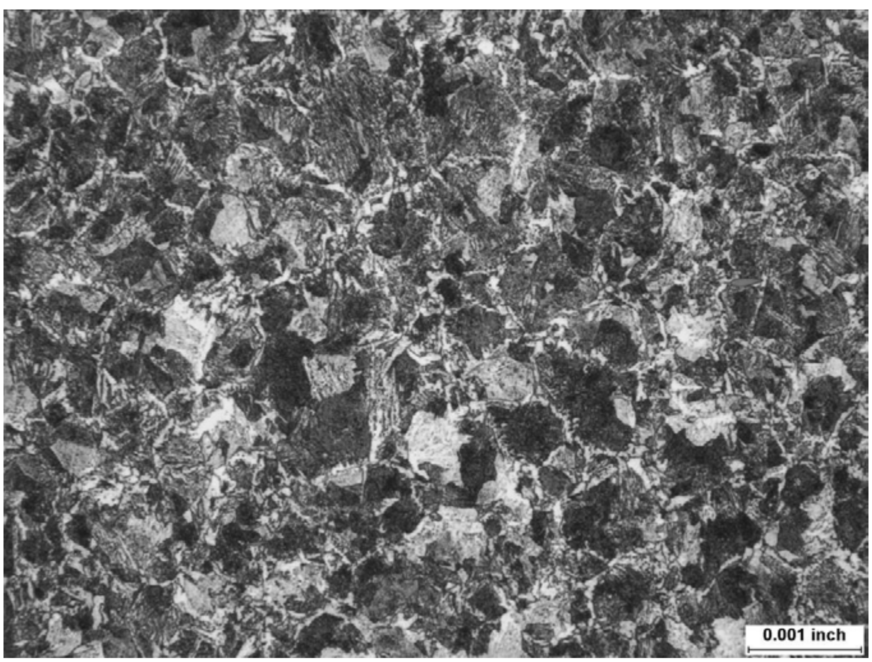


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 195

The micrographs of the primary HAZ display mix-microstructure consisting of grain boundary ferrite and untempered acicular martensite.

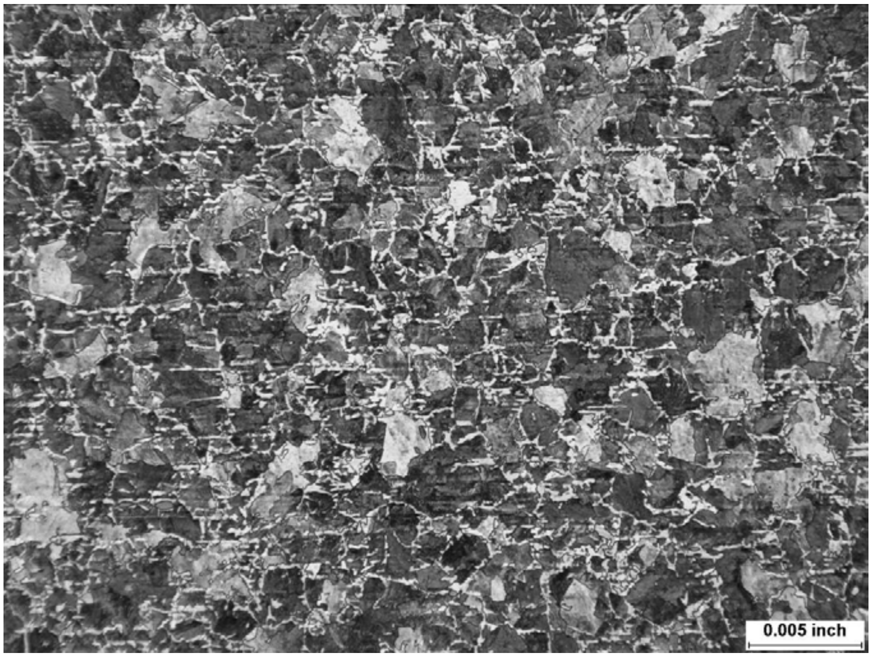


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 196

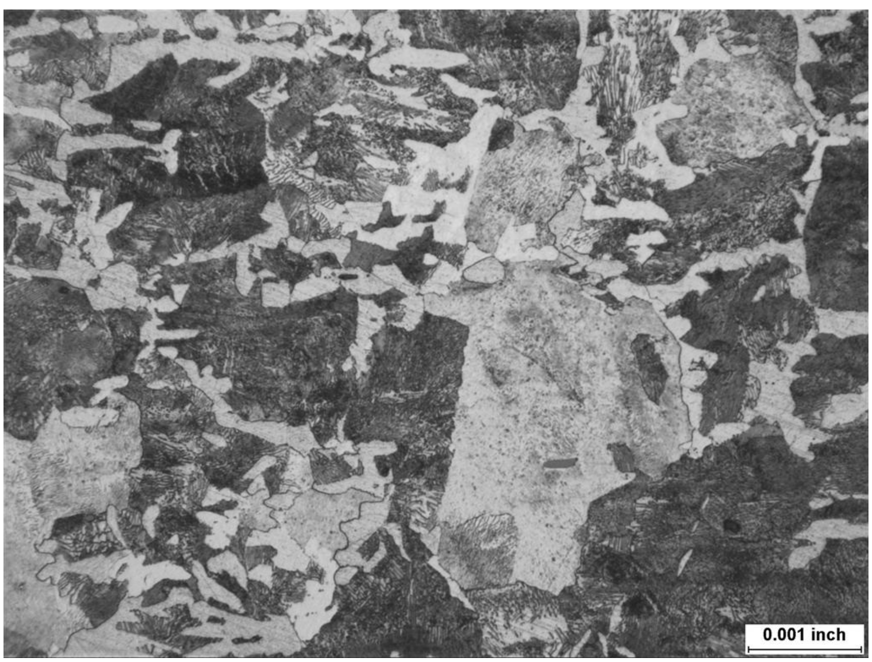


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 197

The micrographs of the secondary HAZ display essentially the grain boundary ferrite and unresolved pearlite.

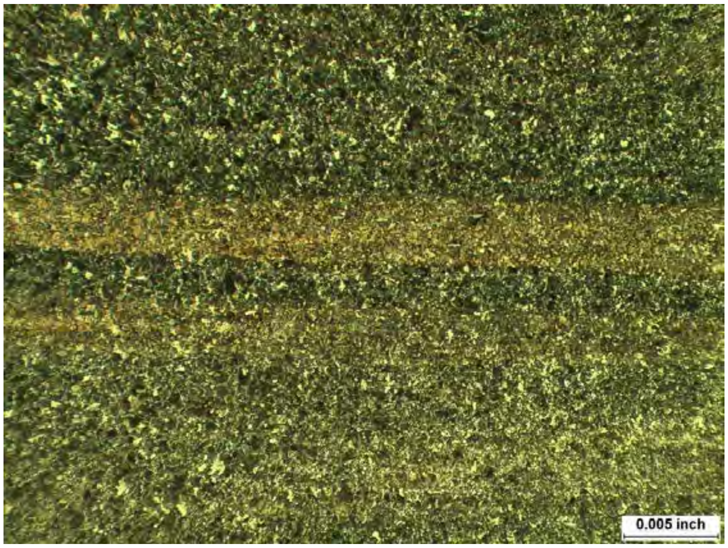


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 198

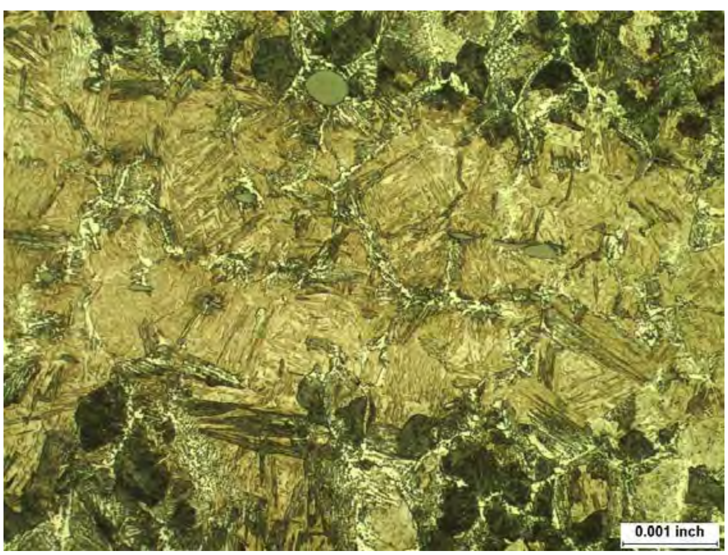


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 199

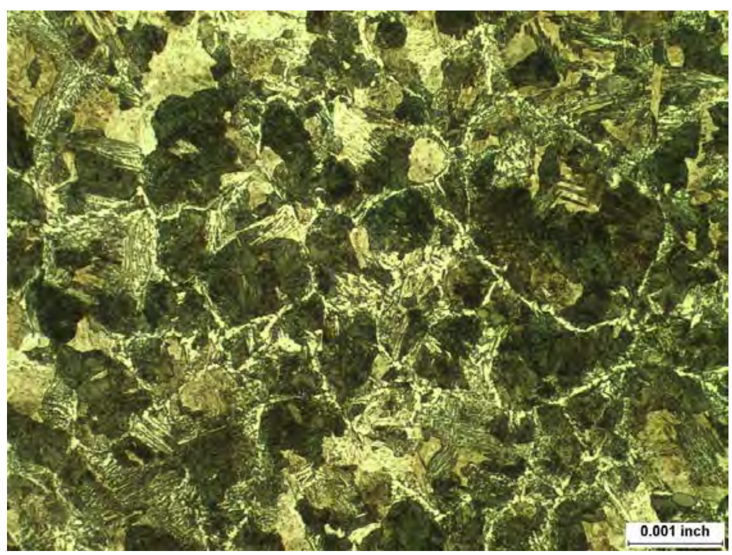
The micrographs of the base metal display the grain boundary ferrite and lamellar pearlite.



20' 6-13/16" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 200



20' 6-13/16" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 201

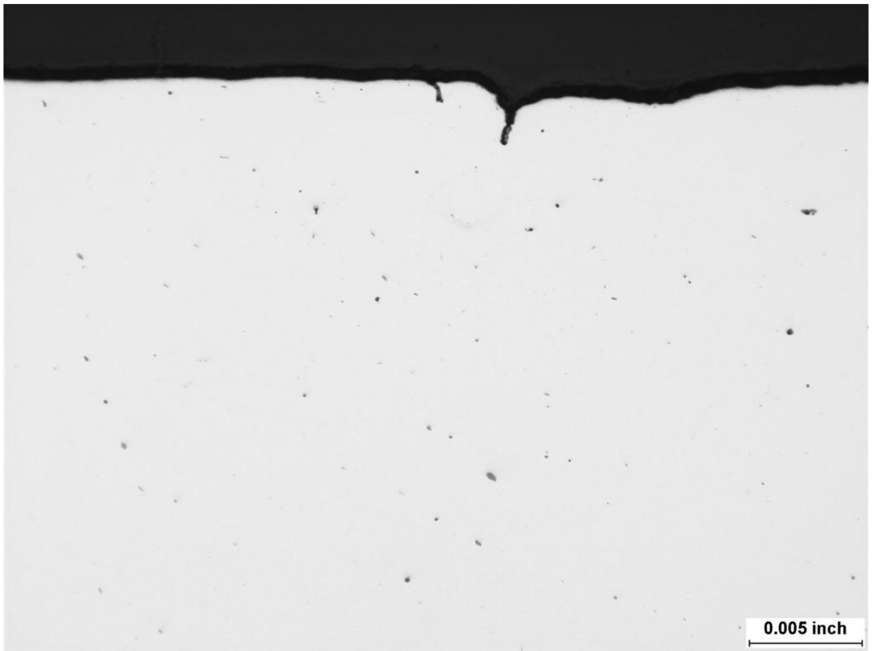


20' 6-13/16" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 202

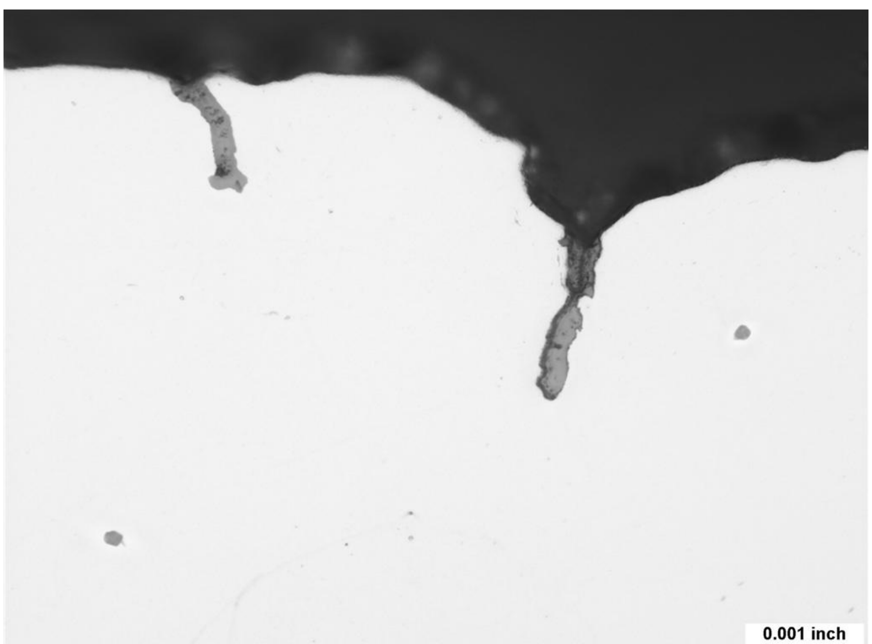
The photographs display banded microstructure in the ERW upset area adjacent to the fusion line, consisting of untempered acicular martensite with entrapped ferrite and ferrite with unresolved bainite in the adjacent non-banded matrix.

35' 8-1/2" from the North Girth Weld
As-polished, ~25x
Photograph No. 203

The micrograph of a cross-section removed from the intact ERW seam at a distance of 35' 8-1/2" from the north girth weld displays an excessive amount of manganese sulfide inclusions, some aligned parallel and diagonal to the fusion line during the seam welding process.



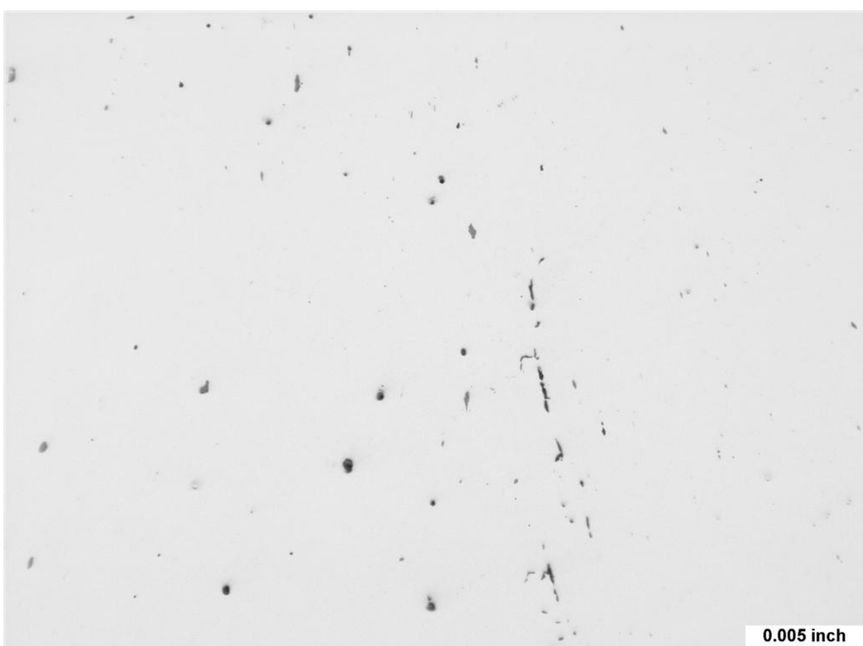
35' 8-1/2" from the North Girth Weld
As-polished, ~100x
Photograph No. 204



35' 8-1/2" from the North Girth Weld
As-polished, ~500x
Photograph No. 205

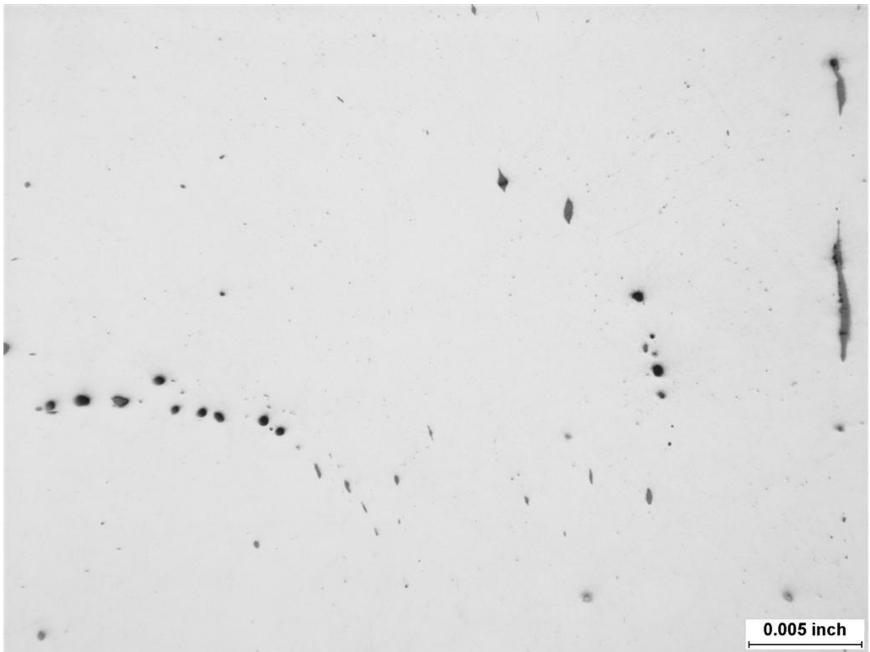
The micrographs display evidence of some oxidation to a shallow depth of 0.0015" in the upset/HAZ.

35' 8-1/2" from the North Girth Weld
As-polished, ~100x
Photograph No. 206

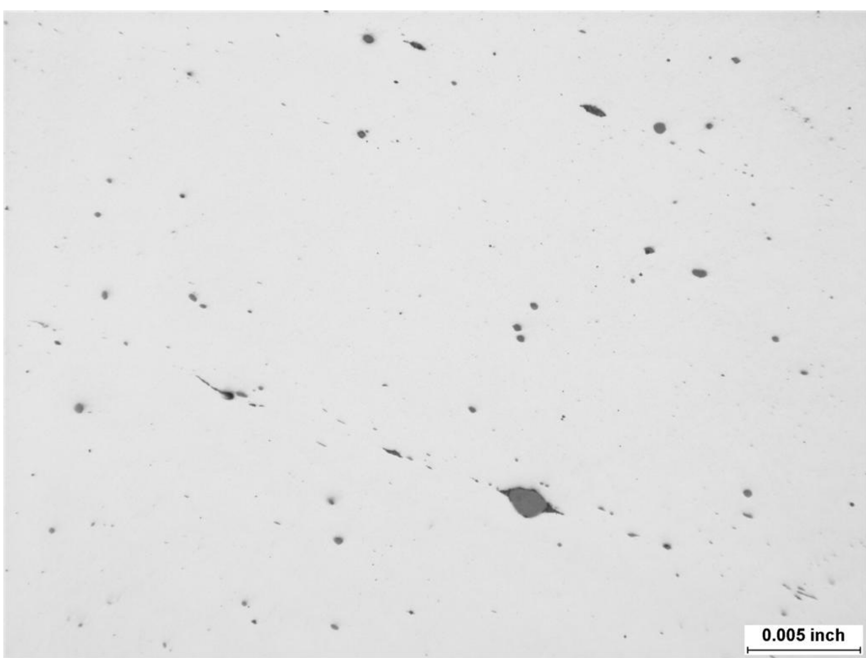


35' 8-1/2" from the North Girth Weld
As-polished, ~100x
Photograph No. 207

The micrographs display an excessive amount of manganese sulfide inclusions aligned parallel and diagonal to the fusion line in the upset/HAZ near the O.D. of the ERW seam joint.

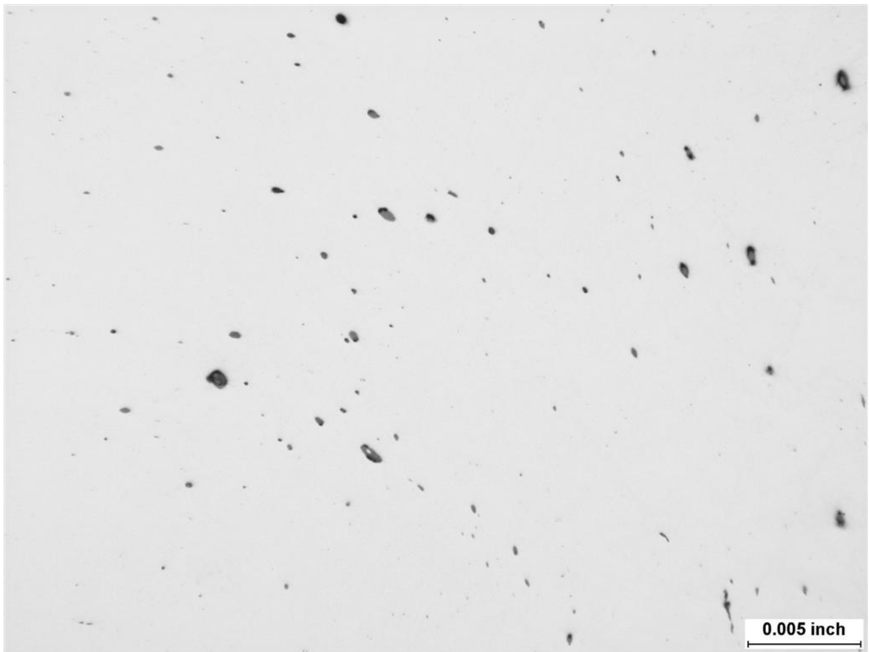


35' 8-1/2" from the North Girth Weld
As-polished, ~100x
Photograph No. 208



35' 8-1/2" from the North Girth Weld
As-polished, ~100x
Photograph No. 209

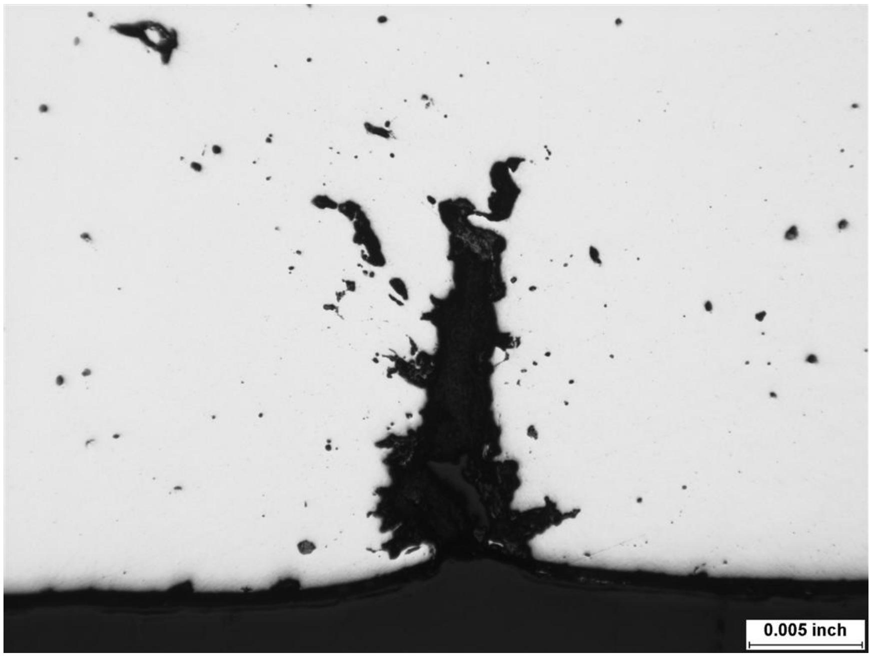
The micrographs display an excessive amount of manganese sulfide inclusions aligned parallel and diagonal to the fusion line in the upset/HAZ near the mid-wall of the ERW seam joint.



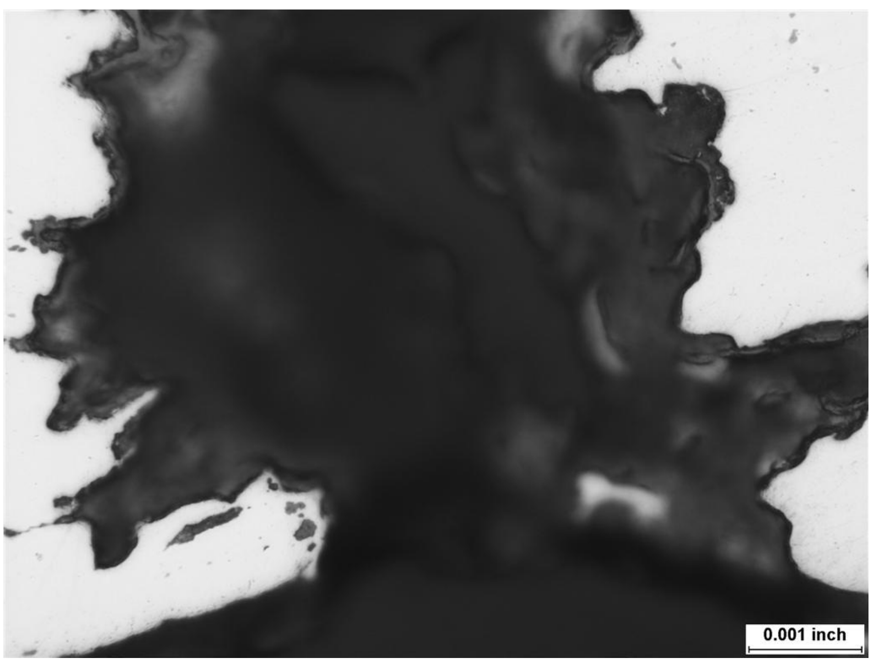
35' 8-1/2" from the North Girth Weld
As-polished, ~100x
Photograph No. 210

35' 8-1/2" from the North Girth Weld
As-polished, ~100x
Photograph No. 211

The micrographs display an excessive amount of manganese sulfide inclusions, many of them aligned parallel and diagonal to the fusion line in the upset/HAZ near the I.D. of the ERW seam joint.

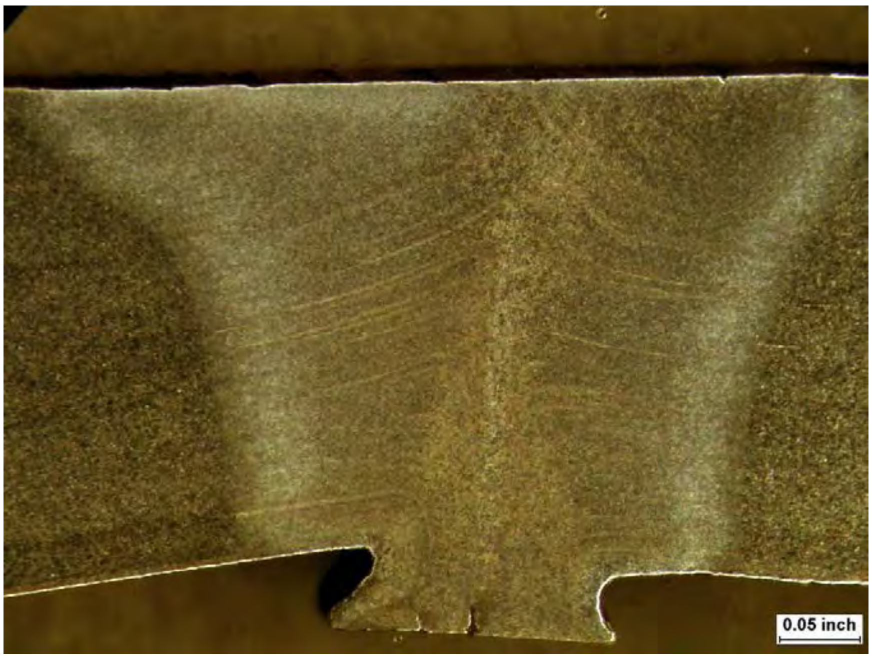


35' 8-1/2" from the North Girth Weld
As-polished, ~100x
Photograph No. 212



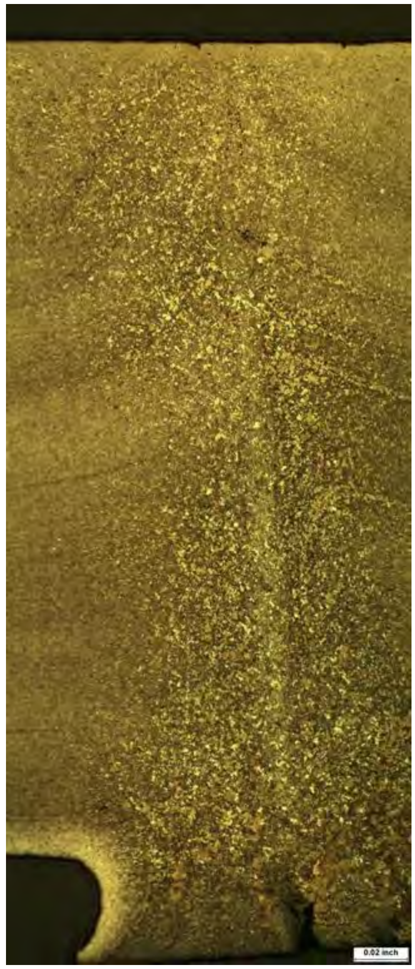
35' 8-1/2" from the North Girth Weld
As-polished, ~500x
Photograph No. 213

The micrographs display unfused, expelled weld flash near the I.D. of the ERW seam joint.



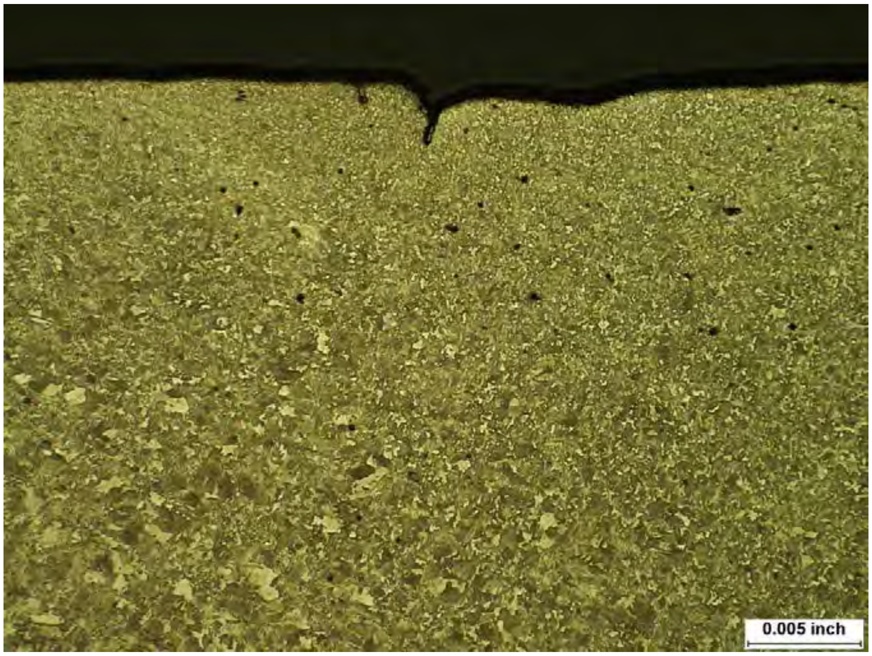
35' 8-1/2" from the North Girth Weld
2% Nital etch, ~20x
Photograph No. 214

The micrograph of the cross-section removed through the intact ERW seam at a distance of 35' 8-1/2" from the north girth weld and prepared for metallographic examination shows upturned as well as downturned bands in the upset/HAZ, with some bands aligned parallel to the fusion line.

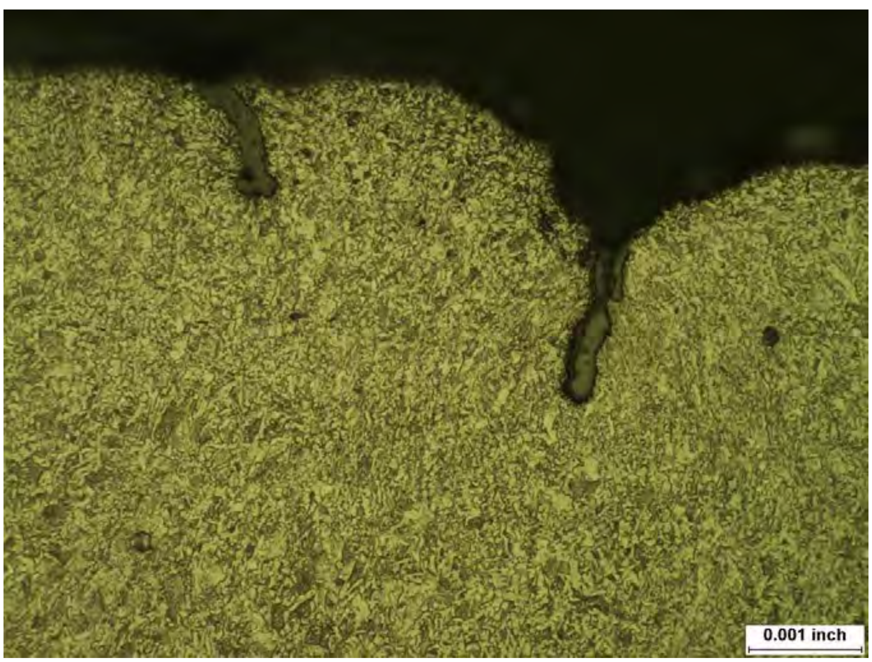


35' 8-1/2" from the North Girth Weld
2% Nital etch, ~25x
Photograph No. 215

The micrograph displays a composite view of the ERW seam cross-section following etching in a 2% Nital solution revealing some upturned grains parallel to the fusion line.

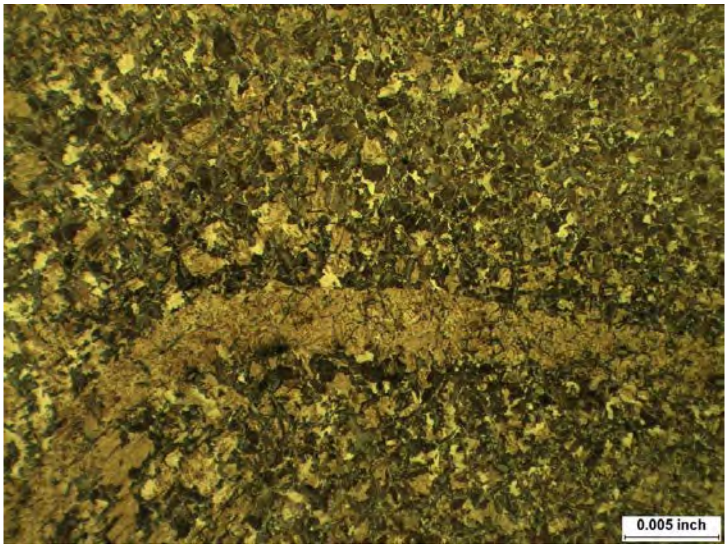


35' 8-1/2" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 216

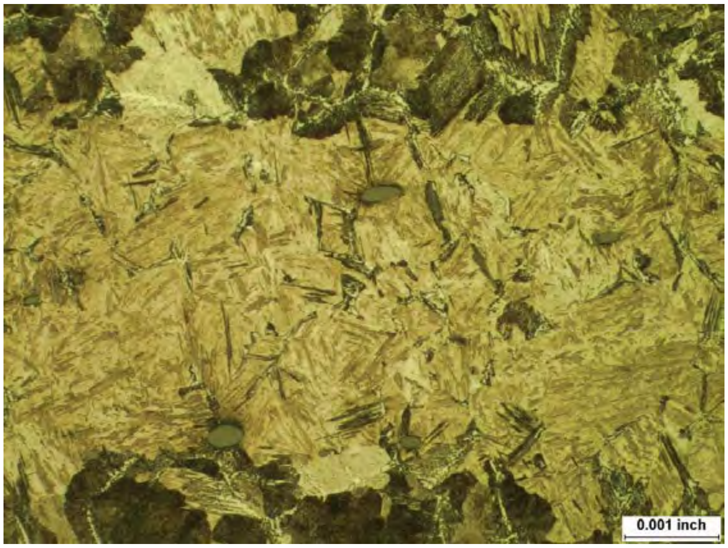


35' 8-1/2" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 217

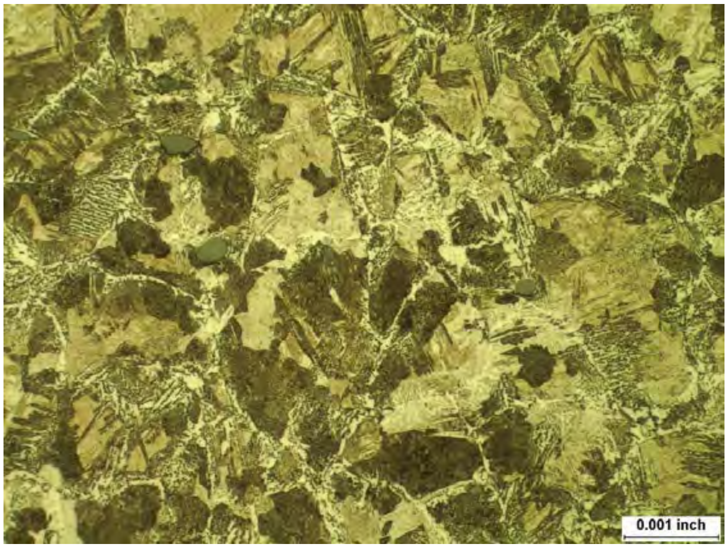
The micrographs display evidence of some oxidation near the O.D. in the upset/HAZ of the ERW seam joint. The microstructure near the O.D. consists of essentially ferrite and pearlite.



35' 8-1/2" from the North Girth Weld
2% Nital etch, ~100x
Photograph No. 218



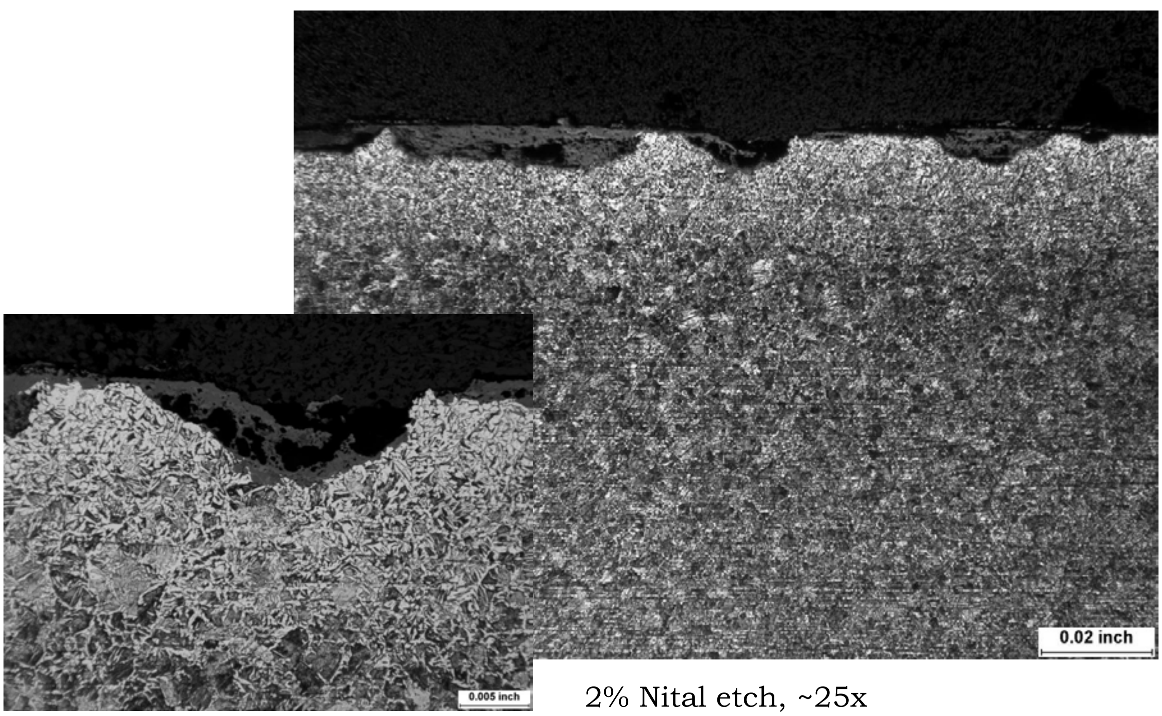
35' 8-1/2" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 219



35' 8-1/2" from the North Girth Weld
2% Nital etch, ~500x
Photograph No. 220

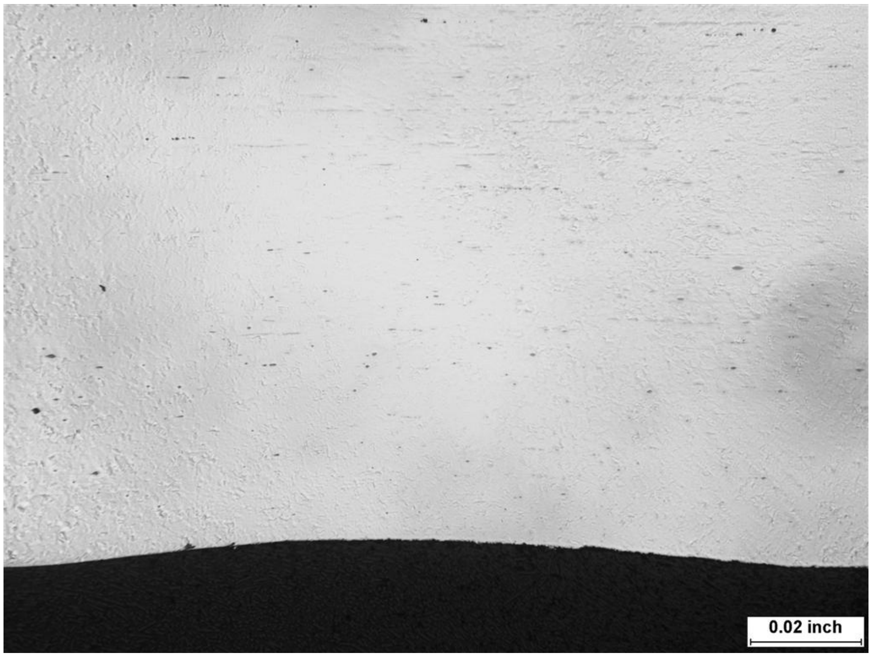
The micrographs display untempered brittle martensite in the bands in the upset/HAZ of the ERW seam joint.

As-polished, ~25x
Photograph No. 221

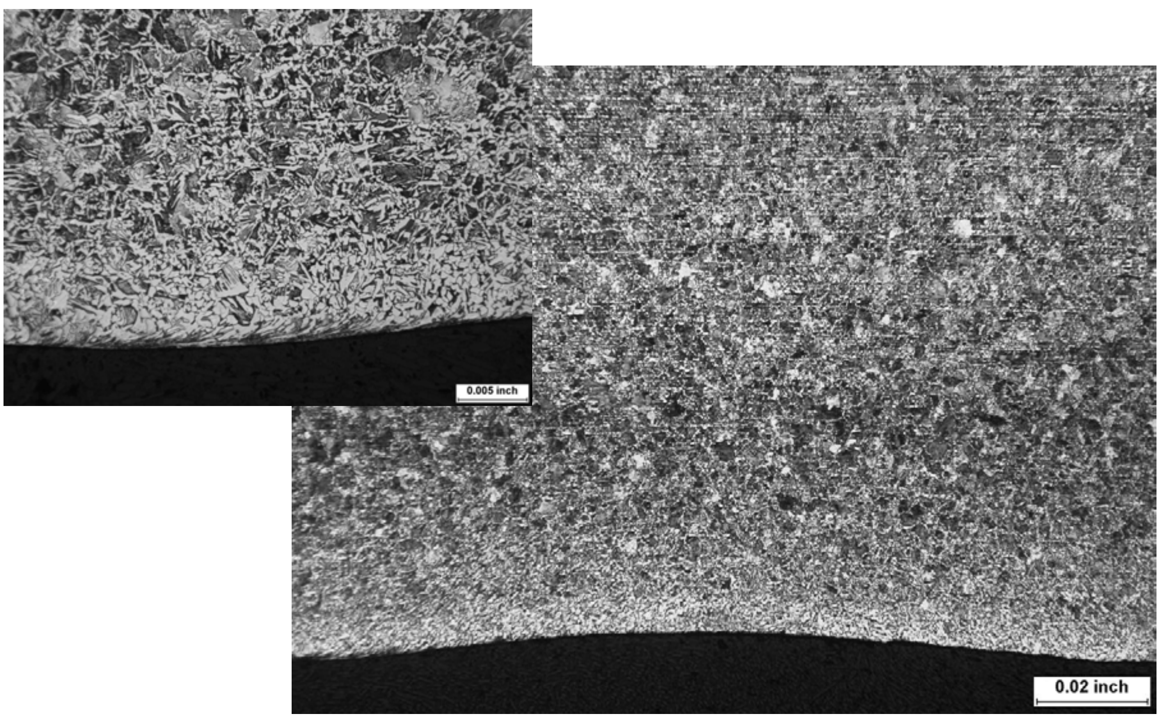


2% Nital etch, ~25x
Photograph No. 222

The micrographs display the microstructural condition at a representative area of the O.D. surface of the pipe, showing the loss of material due to pitting corrosion and the corrosion products adhered to the surface. The insert photograph shows a higher magnification view of a single corrosion pit. The maximum depth of the corrosion pits at this location measured 0.008".



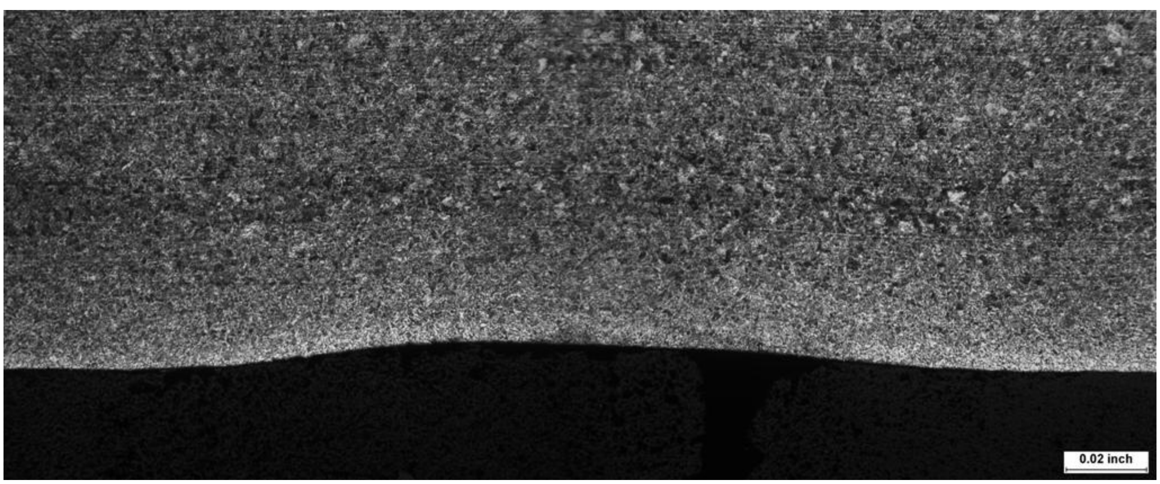
As-polished, ~25x
Photograph No. 223



2% Nital etch, ~25x
Photograph No. 224

The micrographs display the microstructural condition at a representative area of the I.D. surface of the pipe, showing one of the shallow indentations observed during the visual examination. Note the uniform layer of partial decarburization on the I.D. surface and the grain flow deformation shown in the insert photograph, both indicating that the shallow depression is due to a mechanical indentation, most likely when the pipe was manufactured, and not corrosion pitting. The impression measured 0.137" wide and 0.005" deep.

As-polished, ~25x
Photograph No. 225



2% Nital etch, ~25x
Photograph No. 226

The composite micrographs display the microstructural condition at another representative area of the I.D. surface of the pipe, showing one of the shallow indentations observed during the visual examination. Note the uniform layer of partial decarburization on the I.D. surface, indicating that the shallow depression is due to a mechanical indentation, most likely when the pipe was manufactured, and not corrosion pitting. The impression measured 0.189" wide and 0.007" deep.

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

DIMENSIONAL MEASUREMENTS REPORT

TO:

ExxonMobil Pipeline Company

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B,
& ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

TEST METHOD:

Measured using a calibrated and certified micrometer

DATE OF RECEIPT:

April 16, 2013

P.O. NO.:

UCG/451007854

LABORATORY TEST NO.:

CN0413055

IDENTIFICATION:

33' 11-1/2" long Fractured Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

Circumference Location of Measurement		I.D. Measurement Distance from North Girth Weld		
Begins	Ends	-6"	271"	371"
12:00	6:00	19.352"	19.366"	19.392"
1:30	7:30	19.463"	19.375"	19.457"
3:00	9:00	19.353"	19.390"	19.357"
4:30	10:30	19.365"	19.354"	19.437"
Calculated Out of Roundness		0.111"	0.036"	0.100"
API 5L, 44th Edition, Table 10, Pipe Except End Out-of-Roundness Tolerance for Nominal D = 20"				0.400"

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:

Micah Montgomery
Laboratory Technician

May 8, 2013

M. J. Madhani, Chief Metallurgist

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

DIMENSIONAL MEASUREMENTS REPORT

TO:
ExxonMobil Pipeline Company

DATE OF RECEIPT:
April 16, 2013

SPECIFIED MATERIAL:
API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

P.O. NO.:
UCG/451007854

TEST METHOD:
Measured using a calibrated and certified micrometer

LABORATORY TEST NO.:
CN0413055-1

IDENTIFICATION:
33' 11-1/2" long Fractured Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

Distance from North Girth Weld		Wall Thickness at Crack (inches)		Distance from North Girth Weld		Wall Thickness at Crack (inches)		Distance from North Girth Weld		Wall Thickness at Crack (inches)	
(feet)	(inches)	West	East	(feet)	(inches)	West	(East	(feet)	(inches)	West	East
	40	0.316	0.312		116	0.317	0.313	16	192	0.319	0.315
	42	0.317	0.317		118	0.317	0.314		194	0.320	0.315
	44	0.317	0.311	10	120	0.318	0.313		196	0.318	0.314
	46	0.312	0.311		122	0.316	0.313		198	0.318	0.314
4	48	0.311	0.312		124	0.317	0.313		200	0.319	0.315
	50	0.311	0.314		126	0.318	0.314		202	0.319	0.314
	52	0.316	0.312		128	0.319	0.313	17	204	0.319	0.313
	54	0.313	0.311		130	0.318	0.314		206	0.319	0.315
	56	0.313	0.311	11	132	0.317	0.314		208	0.320	0.315
	58	0.313	0.312		134	0.317	0.314		210	0.319	0.316
5	60	0.315	0.312		136	0.317	0.314		212	0.320	0.313
	62	0.313	0.313		138	0.318	0.315		214	0.320	0.313
	64	0.313	0.312		140	0.318	0.315	18	216	0.319	0.313
	66	0.313	0.311		142	0.319	0.314		218	0.318	0.315
	68	0.314	0.311	12	144	0.319	0.315		220	0.318	0.314
	70	0.314	0.310		146	0.319	0.317		222	0.318	0.313
6	72	0.315	0.311		148	0.320	0.315		224	0.317	0.315
	74	0.314	0.312		150	0.320	0.314		226	0.318	0.313
	76	0.317	0.313		152	0.320	0.314	19	228	0.318	0.313
	78	0.315	0.313		154	0.320	0.315		230	0.318	0.312
	80	0.315	0.312	13	156	0.320	0.314		232	0.318	0.313
	82	0.315	0.314		158	0.321	0.315		234	0.319	0.314
7	84	0.315	0.312		160	0.319	0.315		236	0.318	0.314
	86	0.316	0.314		162	0.319	0.313		238	0.316	0.313
	88	0.314	0.314		164	0.319	0.313	20	240	0.318	0.312
	90	0.315	0.313		166	0.318	0.313		242	0.317	0.313
	92	0.316	0.313	14	168	0.319	0.315		244	0.317	0.311
	94	0.317	0.314		170	0.320	0.316		246	0.316	0.311
8	96	0.316	0.314		172	0.318	0.315		248	0.316	0.311
	98	0.315	0.314		174	0.319	0.314		250	0.316	0.311
	100	0.317	0.314		176	0.318	0.314	21	252	0.317	0.311
	102	0.316	0.314		178	0.319	0.315		254	0.315	0.312
	104	0.317	0.314	15	180	0.319	0.313		256	0.316	0.312
	106	0.317	0.318		182	0.318	0.313		258	0.315	0.312
9	108	0.315	0.314		184	0.320	0.315		260	0.315	0.313
	110	0.317	0.315		186	0.320	0.316		262	0.315	0.313
	112	0.316	0.315		188	0.320	0.315	22	264	0.314	0.311
	114	0.317	0.314		190	0.319	0.315		266	*	0.311

*Unable to measure due to geometry of crack tip.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:
Micah Montgomery
Laboratory Technician

April 24, 2013

M. J. Madhani, Chief Metallurgist

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

DIMENSIONAL MEASUREMENTS REPORT

TO:
ExxonMobil Pipeline Company
SPECIFIED MATERIAL:
API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, &
ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42
TEST METHOD:
Measured using an Optical Stereomicroscope and calibrated Image Analysis Software

DATE OF RECEIPT:
April 16, 2013
P.O. NO.:
UCG/451007854
LABORATORY TEST NO.:
CN0413055

IDENTIFICATION:
33' 11-1/2" long Fractured Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

Distance from North Girth Weld	Depth of Cracks Below Surface (inches) O.D.	I.D.	Distance from North Girth Weld	Depth of Cracks Below Surface (inches) O.D.	I.D.	Distance from North Girth Weld	Depth of Cracks Below Surface (inches) O.D.	I.D.
19' 10"	*	*	20' 2"	0.109	*	20' 6"	0.135	*
19' 10-1/8"	0.078	*	20' 2-1/8"	0.102	*	20' 6-1/8"	0.144	*
19' 10-1/4"	0.079	*	20' 2-1/4"	0.104	*	20' 6-1/4"	0.137	*
19' 10-3/8"	0.087	*	20' 2-3/8"	0.093	*	20' 6-3/8"	0.137	*
19' 10-1/2"	0.093	*	20' 2-1/2"	0.104	*	20' 6-1/2"	0.141	0.017
19' 10-5/8"	0.082	*	20' 2-5/8"	0.107	*	20' 6-5/8"	0.141	0.030
19' 10-3/4"	0.098	*	20' 2-3/4"	0.108	*	20' 6-3/4"	0.138	0.030
19' 10-7/8"	0.091	*	20' 2-7/8"	0.116	*	20' 6-7/8"	0.129	0.050
19' 11"	0.112	*	20' 3"	0.124	*	20' 7"	0.141	0.029
19' 11-1/8"	0.104	*	20' 3-1/8"	0.124	*	20' 7-1/8"	0.150	0.025
19' 11-1/4"	0.107	*	20' 3-1/4"	0.133	*	20' 7-1/4"	0.148	0.027
19' 11-3/8"	0.105	*	20' 3-3/8"	0.128	*	20' 7-3/8"	0.150	*
19' 11-1/2"	0.113	*	20' 3-1/2"	0.136	*	20' 7-1/2"	0.141	*
19' 11-5/8"	0.107	*	20' 3-5/8"	0.144	*	20' 7-5/8"	0.098	*
19' 11-3/4"	0.102	*	20' 3-3/4"	0.148	*	20' 7-3/4"	0.092	*
19' 11-7/8"	0.092	*	20' 3-7/8"	0.141	*	20' 7-7/8"	0.078	*
20'	0.102	*	20' 4"	0.140	*	20' 8"	0.133	*
20' 1/8"	0.099	*	20' 4-1/8"	0.136	*	20' 8-1/8"	0.138	*
20' 1/4"	0.102	*	20' 4-1/4"	0.142	*	20' 8-1/4"	0.136	*
20' 3/8"	0.101	*	20' 4-3/8"	0.140	*	20' 8-3/8"	0.132	*
20' 1/2"	0.125	*	20' 4-1/2"	0.137	*	20' 8-1/2"	0.131	*
20' 5/8"	0.110	*	20' 4-5/8"	0.140	*	20' 8-5/8"	0.138	*
20' 3/4"	0.109	*	20' 4-3/4"	0.135	*	20' 8-3/4"	0.140	*
20' 7/8"	0.104	*	20' 4-7/8"	0.135	*	20' 8-7/8"	0.133	*
20' 1"	0.094	*	20' 5"	0.133	*	20' 9"	0.111	*
20' 1-1/8"	0.117	*	20' 5-1/8"	0.113	*	20' 9-1/8"	0.140	*
20' 1-1/4"	0.112	*	20' 5-1/4"	0.123	*	20' 9-1/4"	0.078	*
29' 1-3/8"	0.103	*	20' 5-3/8"	0.125	*	20' 9-3/8"	0.091	*
20' 1-1/2"	0.114	*	20' 5-1/2"	0.140	*	20' 9-1/2"	0.086	*
20' 1-5/8"	0.109	*	20' 5-5/8"	0.138	*	20' 9-5/8"	0.085	*
20' 1-3/4"	0.103	*	20' 5-3/4"	0.135	*	20' 9-3/4"	0.074	*
20' 1-7/8"	0.106	*	20' 5-7/8"	0.138	*	20' 9-7/8"	0.079	*

*No hook cracks at this location.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:
Susan Dalrymple-Ely
Susan Dalrymple-Ely
Materials Analyst

April 26, 2013

MJMadhani
M. J. Madhani, Chief Metallurgist

Table 3 (Cont'd)

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2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

DIMENSIONAL MEASUREMENTS REPORT

TO:
ExxonMobil Pipeline Company
SPECIFIED MATERIAL:
API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42
TEST METHOD:
Measured using an Optical Stereomicroscope and calibrated Image Analysis Software
IDENTIFICATION:
33' 11-1/2" long Fractured Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

DATE OF RECEIPT:
April 16, 2013
P.O. NO.:
UCG/451007854
LABORATORY TEST NO.:
CN0413055

Distance from North Girth Weld	Depth of Cracks Below Surface (inches) O.D.	I.D.	Distance from North Girth Weld	Depth of Cracks Below Surface (inches) O.D.	I.D.	Distance from North Girth Weld	Depth of Cracks Below Surface (inches) O.D.	I.D.
20' 10"	0.077	*	21' 3"	0.027	0.057	21' 8"	*	0.068
20' 10-1/8"	0.085	*	21' 3-1/8"	0.031	*	21' 8-1/8"	*	0.078
20' 10-1/4"	0.075	*	21' 3-1/4"	0.052	*	21' 8-1/4"	*	0.079
20' 10-3/8"	0.057	0.081	21' 3-3/8"	0.118	*	21' 8-3/8"	*	0.079
20' 10-1/2"	0.060	0.083	21' 3-1/2"	0.124	0.088	21' 8-1/2"	*	0.085
20' 10-5/8"	0.069	0.091	21' 3-5/8"	0.130	0.094	21' 8-5/8"	*	0.088
20' 10-3/4"	0.064	0.088	21' 3-3/4"	0.130	0.091	21' 8-3/4"	*	0.082
20' 10-7/8"	0.061	0.088	21' 3-7/8"	0.122	0.086	21' 8-7/8"	*	0.092
20' 11"	0.055	*	21' 4"	0.133	0.091	21' 9"	*	0.080
20' 11-1/8"	0.038	*	21' 4-1/8"	0.134	*	21' 9-1/8"	*	0.071
20' 11-1/4"	0.036	*	21' 4-1/4"	0.135	*	21' 9-1/4"	*	0.057
20' 11-3/8"	0.044	*	21' 4-3/8"	0.135	*	21' 9-3/8"	*	*
20' 11-1/2"	*	*	21' 4-1/2"	0.140	*	21' 9-1/2"	*	*
20' 11-5/8"	*	*	21' 4-5/8"	0.138	*	21' 9-5/8"	*	*
20' 11-3/4"	*	*	21' 4-3/4"	0.124	*	21' 9-3/4"	*	*
20' 11-7/8"	*	*	21' 4-7/8"	0.126	*	21' 9-7/8"	*	*
21'	*	*	21' 5"	0.117	*	21' 10"	*	*
21' 1/8"	*	*	21' 5-1/8"	0.112	*	21' 10-1/8"	*	*
21' 1/4"	*	*	21' 5-1/4"	0.133	*	21' 10-1/4"	*	*
21' 3/8"	0.039	*	21' 5-3/8"	0.130	*	21' 10-3/8"	*	*
21' 1/2"	0.029	*	21' 5-1/2"	0.120	*	21' 10-1/2"	*	*
21' 5/8"	0.040	*	21' 5-5/8"	0.112	0.044	21' 10-5/8"	*	*
21' 3/4"	0.016	*	21' 5-3/4"	0.119	0.095	21' 10-3/4"	*	*
21' 7/8"	0.028	*	21' 5-7/8"	0.126	0.096	21' 10-7/8"	*	*
21' 1"	0.038	*	21' 6"	0.122	0.092	21' 11"	*	*
21' 1-1/8"	0.038	*	21' 6-1/8"	0.107	0.087	21' 11-1/8"	*	*
21' 1-1/4"	0.062	*	21' 6-1/4"	0.106	0.084	21' 11-1/4"	*	*
21' 1-3/8"	0.029	*	21' 6-3/8"	0.110	0.070	21' 11-3/8"	*	*
21' 1-1/2"	0.088	*	21' 6-1/2"	0.112	*	21' 11-1/2"	*	*
21' 1-5/8"	0.077	*	21' 6-5/8"	0.099	*	21' 11-5/8"	*	*
21' 1-3/4"	0.082	*	21' 6-3/4"	0.083	*	21' 11-3/4"	*	*
21' 1-7/8"	0.060	*	21' 6-7/8"	0.089	*	21' 11-7/8"	*	*
21' 2"	0.112	*	21' 7"	0.091	0.046	22"	*	*
21' 2-1/8"	0.110	0.085	21' 7-1/8"	0.092	0.038			
21' 2-1/4"	0.110	0.097	21' 7-1/4"	0.084	0.031			
21' 2-3/8"	0.104	0.098	21' 7-3/8"	0.092	0.039			
21' 2-1/2"	0.103	0.095	21' 7-1/2"	0.096	0.067			
21' 2-5/8"	0.037	0.085	21' 7-5/8"	0.093	0.060			
21' 2-3/4"	0.044	0.080	21' 7-3/4"	0.043	0.065			
21' 2-7/8"	0.037	0.062	21' 7-7/8"	*	0.064			

*No hook cracks at this location.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:
Susan Dalrymple-Ely
Susan Dalrymple-Ely
Materials Analyst

April 26, 2013

MMadhani
M. J. Madhani, Chief Metallurgist

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

DIMENSIONAL MEASUREMENTS OF HOOK CRACKS

TO:

ExxonMobil Pipeline Company

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

TEST METHOD:

Calibrated Image Analysis Software

DATE OF RECEIPT:

April 16, 2013

P.O. NO.:

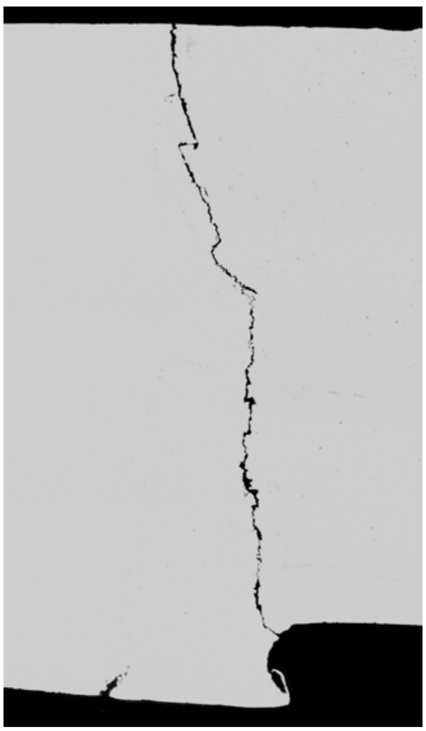
UCG/451007854

LABORATORY TEST NO.:

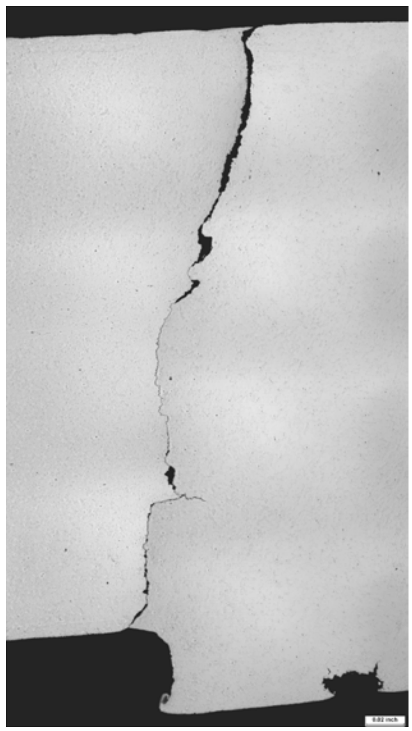
CN0413055

IDENTIFICATION:

33' 11-1/2" long Fractured Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948



20' 3-3/4"



20' 4-7/8"

20' 5-1/2"

Distance from the North Gird Weld	Hook Crack Width Minimum	Hook Crack Width Average	Hook Crack Width Maximum	Hook Crack Depth
20' 3-3/4"	0.0008"	0.0013"	0.0023"	0.145"
20' 4-7/8"	0.0018"	0.0028"	0.0038"	0.145"
20' 5-1/2"	0.0006"	0.0016"	0.0031"	0.133"

Note: The maximum hook crack depth where measured on the fracture surface was measured to be 0.150", as recorded in Table 3.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:

Clint Myers

Clint Myers
Staff Metallurgist

May 14, 2013

M Madhani

M. J. Madhani, Chief Metallurgist

Table 5

HURST METALLURGICAL RESEARCH LABORATORY, INC.
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Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

MICROHARDNESS TEST REPORT

TO:

ExxonMobil Pipeline Company

DATE OF RECEIPT:

April 16, 2013

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

TEST METHOD:

ASTM E384-11$^{\epsilon1}$

P.O. NO.:

UCG/451007854

SCALE:

Vickers

LOAD FORCE:

500 g

INDENTER:

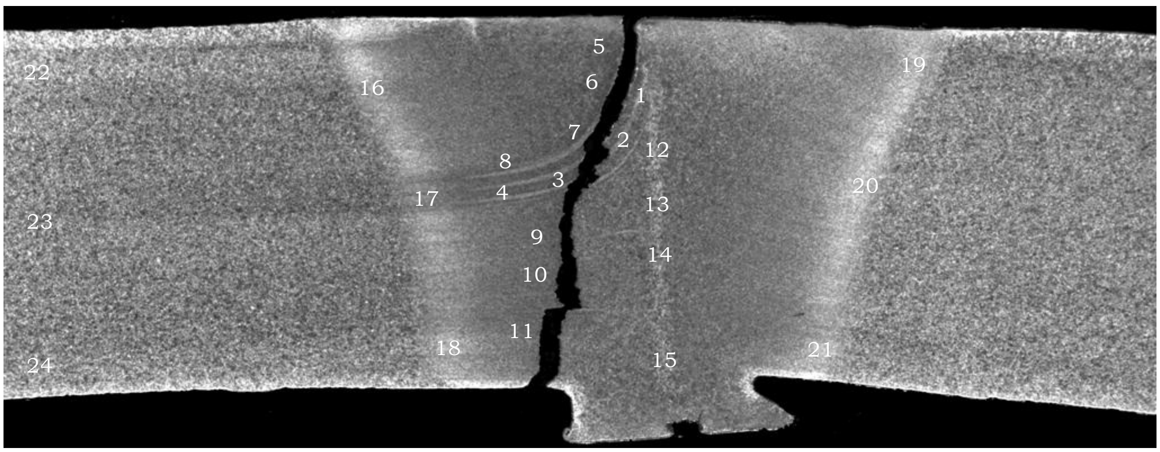
Vickers

LABORATORY TEST NO.:

CN0413055

IDENTIFICATION:

33' 11-1/2" long Fractured Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948; Test Location: 20' 4-7/8" from the North Girth Weld



Indentation Number	Test Location	Hardness, HV500g	Conversion to Rockwell Scale	Indentation Number	Test Location	Hardness, HV500g	Conversion to Rockwell Scale
1	Hardened Upturned Martensitic Grains	549	52 HRC	12	ERW Fusion Line	408	42 HRC
2		560	53 HRC	13		492	49 HRC
3		574	54 HRC	14		399	41 HRC
4		509	50 HRC	15		335	34 HRC
5	Hook Crack(s)	279	27 HRC	16	Secondary HAZ	225	97 HRB
6		285	28 HRC	17		240	20 HRC
7		308	31 HRC	18		226	98 HRB
8		295	29 HRC	19		248	22 HRC
9	Final Fracture (Primary HAZ)	280	27 HRC	20		240	100 HRB
10		298	29 HRC	21		240	100 HRB
11		280	27 HRC	22	Base Metal	206	94 HRB
				23		228	98 HRB
				24		218	96 HRB

Test was performed using calibrated Wilson Tukon Model 230 Tester, S/N 892214. Rockwell hardness numbers converted from Knoop or Vickers scales are approximations based on ASTM E 140-07 and are typically higher than the hardness values obtained using the actual scale.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:

J. E.

DATE TESTED:

May 10, 2013

Joseph Eskew, C.W.I., Laboratory Services Manager

Table 6

HURST METALLURGICAL RESEARCH LABORATORY, INC.
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Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

MICROHARDNESS TEST REPORT

TO:

ExxonMobil Pipeline Company

DATE OF RECEIPT:

April 16, 2013

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

TEST METHOD:

ASTM E384-11$^{\epsilon 1}$

P.O. NO.:

UCG/451007854

SCALE:

Vickers

LOAD FORCE:

500 g

INDENTER:

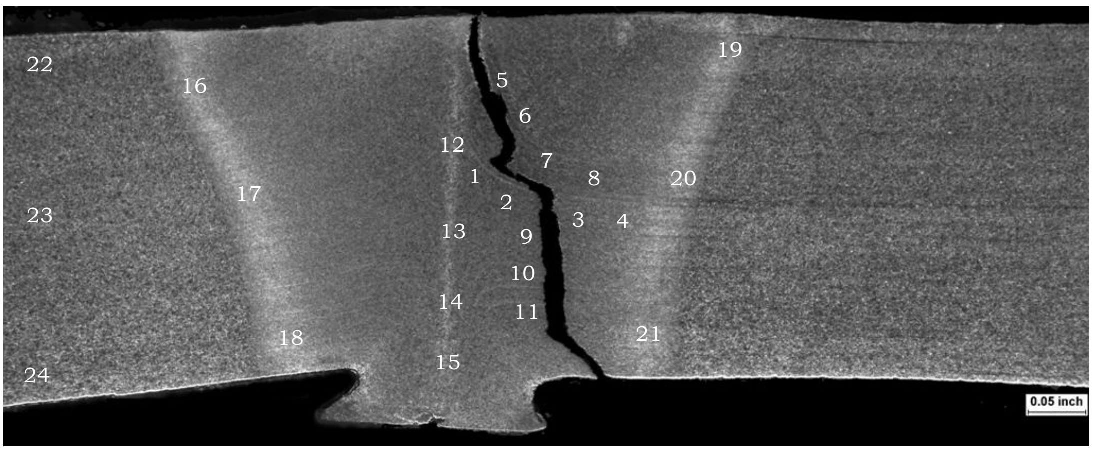
Vickers

LABORATORY TEST NO.:

CN0413055

IDENTIFICATION:

33' 11-1/2" long Fractured Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948; Test Location: 20' 6-13/16" from the North Girth Weld



Indentation Number	Test Location	Hardness, HV500g	Conversion to Rockwell Scale
1	Hardened Upturned Martensitic Grains	483	48 HRC
2		483	48 HRC
3		499	49 HRC
4		502	49 HRC
5	Hook Crack(s)	281	27 HRC
6		293	29 HRC
7		310	31 HRC
8		297	29 HRC
9	Final Fracture (Primary HAZ)	338	34 HRC
10		265	25 HRC
11		298	29 HRC

Indentation Number	Test Location	Hardness, HV500g	Conversion to Rockwell Scale
12	ERW Fusion Line	303	30 HRC
13		342	35 HRC
14		330	33 HRC
15		299	30 HRC
16	Secondary HAZ	255	23 HRC
17		231	98 HRB
18		246	22 HRC
19		233	99 HRB
20		258	24 HRC
21		231	98 HRB
22	Base Metal	223	97 HRB
23		250	22 HRC
24		237	100 HRB

Test was performed using calibrated Wilson Tukon Model 230 Tester, S/N 892214. Rockwell hardness numbers converted from Knoop or Vickers scales are approximations based on ASTM E 140-07 and are typically higher than the hardness values obtained using the actual scale.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:

J. E.

DATE TESTED:

May 10, 2013

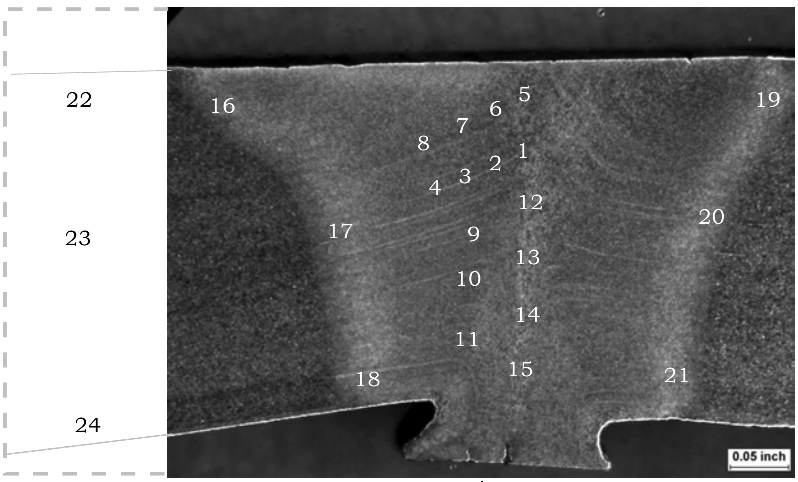
Joseph Eskew, C.W.I., Laboratory Services Manager

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

MICROHARDNESS TEST REPORT

TO: ExxonMobil Pipeline Company			DATE OF RECEIPT: April 16, 2013
SPECIFIED MATERIAL: API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42		TEST METHOD: ASTM E384-11$^{\epsilon 1}$	P.O. NO.: UCG/451007854
SCALE: Vickers	LOAD FORCE: 500 g	INDENTER: Vickers	LABORATORY TEST NO.: CN0413055

IDENTIFICATION:
19' 10" long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948; Test Location: 35' 8-1/2" from the North Girth Weld



Indentation Number	Test Location	Hardness, HV500g	Conversion to Rockwell Scale	Indentation Number	Test Location	Hardness, HV500g	Conversion to Rockwell Scale
1	Hardened Upturned Martensitic Grains	580	54 HRC	12	ERW Fusion Line	334	34 HRC
2		586	54 HRC	13		295	29 HRC
3		391	40 HRC	14		374	38 HRC
4		444	45 HRC	15		516	50 HRC
5	Primary HAZ	256	23 HRC	16	Secondary HAZ	237	100 HRB
6		253	23 HRC	17		241	21 HRC
7		276	27 HRC	18		228	98 HRB
8		269	26 HRC	19		253	23 HRC
9		283	28 HRC	20		234	99 HRB
10		241	21 HRC	21		219	97 HRB
11		254	23 HRC	22	Base Metal	232	99 HRB
				23		231	99 HRB
				24		249	22 HRC

Test was performed using calibrated Wilson Tukon Model 230 Tester, S/N 892214. Rockwell hardness numbers converted from Knoop or Vickers scales are approximations based on ASTM E 140-07 and are typically higher than the hardness values obtained using the actual scale.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:	*DATE TESTED:*	
J. E.	May 10, 2013	Joseph Eskew, C.W.I., Laboratory Services Manager

HMRL
HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

TENSILE TEST REPORT

TO:

ExxonMobil Pipeline Company

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

TEST METHOD:

Prepared per: API STD. 5-L, 10th Edition, August 1945, Sections 24 - 27, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 10.2.3 and Fig. 5b
Tested per: ASTM A370-12a

DATE OF RECEIPT:

April 16, 2013

P.O. NO.:

UCG/451007854

LABORATORY TEST NO.:

PT0413163 - ERW

ACCEPTANCE CRITERION:

API STD. 5-L, 10th Edition, August 1945, Table 3, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Table 6, Welded Pipe, Grade X42

IDENTIFICATION:

19' 10" long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

SAMPLE NUMBER	SPECIMEN IDENTIFICATION	TEST SPECIMEN DIMENSIONS			ULTIMATE STRESS		YIELD STRESS (0.5% OFFSET)		% ELONG. IN 2"	FRACTURE LOCATION
		DIAMETER/ WIDTH, in	THICKNESS, in	AREA, in²	LOAD, lbf	STRESS, psi	LOAD, lbf	STRESS, psi		
1	Transverse - ERW Seam, Weld Flash Included	1.503	0.294	0.442	44,754	101,000	34,016	77,000	4	H.A.Z.
2		1.501	0.295	0.443	41,394	93,500	34,938	79,000	5	H.A.Z.
3		1.508	0.294	0.443	45,191	102,000	37,194	84,000	23	Base Metal
1	Transverse - ERW Seam, Weld Flash Removed	1.509	0.282	0.426	36,353	85,500	31,104	73,000	3	H.A.Z.
2		1.509	0.281	0.424	36,341	85,500	31,858	75,000	3	H.A.Z.
3		1.504	0.281	0.423	39,172	92,500	32,440	77,000	5	H.A.Z.
REQUIREMENTS										
API 5-L, 10th Edition, Table 3, Electric Welded, Open Hearth Steel, Grade B						60,000 minimum				
API 5L, 44th Edition, PSL 1, Table 6, Welded Pipe, Grade X42						60,200 minimum				

REMARKS:

Test specimens meet the tensile requirements for API 5L ERW pipe at the time the pipe was manufactured, as well as the current version of API 5L for ERW Pipe, in accordance with the above referenced acceptance criterion.

Transverse tensile test specimens were flattened as per API 5L test methods prior to machining and testing.

Test was performed using Instron Satec Systems tensile machine S/N 1189.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:

Josh Thomas
Laboratory Technician

DATE TESTED:

May 1, 2013

Joseph Eskew, C.W.I., Laboratory Services Manager

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

TENSILE TEST REPORT

TO:

ExxonMobil Pipeline Company

DATE OF RECEIPT:

April 16, 2013

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

P.O. NO.:

UCG/451007854

TEST METHOD:

Prepared per: API STD. 5-L, 10th Edition, August 1945, Sections 24 - 27, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 10.2.3 and Fig. 5b
Tested per: ASTM A370-12a

LABORATORY TEST NO.:

PT0413163 - T

ACCEPTANCE CRITERION:

API STD. 5-L, 10th Edition, August 1945, Table 3, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Table 6, Welded Pipe, Grade X42

IDENTIFICATION:

19' 10" long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

SAMPLE NUMBER	SPECIMEN IDENTIFICATION	TEST SPECIMEN DIMENSIONS			ULTIMATE STRESS		YIELD STRESS (0.5% OFFSET)		% ELONG. IN 2"	FRACTURE LOCATION
		DIAMETER/ WIDTH, in	THICKNESS, in	AREA, in^2	LOAD, lbf	STRESS, psi	LOAD, lbf	STRESS, psi		
1	Transverse - 90° from ERW Seam	1.494	0.296	0.442	38,440	87,000	26,343	59,500	30	
2		1.503	0.297	0.446	38,628	86,500	26,288	59,000	31	
3		1.510	0.293	0.442	39,329	89,000	27,386	62,000	28	
1	Transverse - 180° from ERW Seam	1.507	0.306	0.461	40,051	87,000	28,967	63,000	28	
2		1.508	0.307	0.463	39,620	85,500	27,856	60,000	28	
3		1.501	0.306	0.459	40,254	87,500	29,443	64,000	28	

REQUIREMENTS

Requirement	LOAD, lbf	STRESS, psi	LOAD, lbf	STRESS, psi	% ELONG. IN 2"	FRACTURE LOCATION
API 5-L, 10th Edition, Table 3, Electric Welded, Open Hearth Steel, Grade B		60,000 minimum		35,000 min.	*	
API 5L, 44th Edition, PSL 1, Table 6, Welded Pipe, Grade X42		60,200 minimum		42,100 min.	27 min.	

REMARKS:

Test specimens meet the tensile requirements for API 5L ERW pipe at the time the pipe was manufactured, as well as the current version of API 5L for ERW Pipe, in accordance with the above referenced acceptance criterion.

Transverse tensile test specimens were flattened as per API 5L test methods prior to machining and testing.

*The required minimum elongation specified in Table 3 of API STD. 5-L, 10th Edition is illegible on the available paper copy.

Test was performed using Instron Satec Systems tensile machine S/N 1189.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:
Josh Thomas
Laboratory Technician

DATE TESTED:
May 1, 2013

Joseph Eskew, C.W.I., Laboratory Services Manager

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

TENSILE TEST REPORT

TO:
ExxonMobil Pipeline Company

DATE OF RECEIPT:
April 16, 2013

SPECIFIED MATERIAL:
API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

P.O. NO.:
UCG/451007854

TEST METHOD:
Prepared per: API STD. 5-L, 10th Edition, August 1945, Sections 24 - 27, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 10.2.3 and Fig. 5b
Tested per: ASTM A370-12a

LABORATORY TEST NO.:
PT0413163 - L

ACCEPTANCE CRITERION:
API STD. 5-L, 10th Edition, August 1945, Table 3, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Table 6, Welded Pipe, Grade X42

IDENTIFICATION:
19' 10" long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

SAMPLE NUMBER	SPECIMEN IDENTIFICATION	TEST SPECIMEN DIMENSIONS			ULTIMATE STRESS		YIELD STRESS (0.5% OFFSET)		% ELONG. IN 2"	FRACTURE LOCATION
		DIAMETER/ WIDTH, in	THICKNESS, in	AREA, in²	LOAD, lbf	STRESS, psi	LOAD, lbf	STRESS, psi		
1	Longitudinal - 90° from ERW Seam	1.504	0.286	0.430	38,346	89,000	27,764	64,500	31	
2		1.507	0.290	0.437	39,155	90,000	29,107	66,500	31	
3		1.503	0.294	0.442	40,043	90,500	30,203	68,500	31	

REQUIREMENTS

Requirement	Ultimate Stress, psi	Yield Stress, psi	% Elong.
API 5-L, 10th Edition, Table 3, Electric Welded, Open Hearth Steel, Grade B	60,000 minimum	35,000 min.	*
API 5L, 44th Edition, PSL 1, Table 6, Welded Pipe, Grade X42	60,200 minimum	42,100 min.	27 min.

REMARKS:

Test specimens meet the tensile requirements for API 5L ERW pipe at the time the pipe was manufactured, as well as the current version of API 5L for ERW Pipe, in accordance with the above referenced acceptance criterion.

*The required minimum elongation specified in Table 3 of API STD. 5-L, 10th Edition is illegible on the available paper copy.

Test was performed using Instron Satec Systems tensile machine S/N 1189.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:
Josh Thomas
Laboratory Technician

DATE TESTED:
May 1, 2013

Joseph Eskew, C.W.I., Laboratory Services Manager

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

TENSILE TEST REPORT

TO:

ExxonMobil Pipeline Company

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

TEST METHOD:

Prepared per: API STD. 5-L, 10th Edition, August 1945, Sections 24 - 27, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 10.2.3 and Table 21
Tested per: ASTM A370-12a

DATE OF RECEIPT:

April 16, 2013

P.O. NO.:

UCG/451007854

LABORATORY TEST NO.:

PT0413160

ACCEPTANCE CRITERION:

API STD. 5-L, 10th Edition, August 1945, Table 3, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Table 6, Welded Pipe, Grade X42

IDENTIFICATION:

19' 10" long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

SPECIMEN IDENTIFICATION	TEST SPECIMEN DIMENSIONS			ULTIMATE STRESS		YIELD STRESS (0.5% OFFSET)		% ELONG. IN 2"	% R. IN A.
	DIAMETER/ WIDTH, in	THICKNESS, in	AREA, in^2	LOAD, lbf	STRESS, psi	LOAD, lbf	STRESS, psi		
Transverse - 90° from ERW Seam	0.245	0.300	0.0735	6,326	86,000	4,169	56,500	27	
Transverse - 180° from ERW Seam	0.253	0.307	0.0777	6,492	83,500	4,503	58,000	22	
REQUIREMENTS									
API 5-L, 10th Edition, Table 3, Electric Welded, Open Hearth Steel, Grade B					60,000 minimum		35,000 min.	*	
API 5L, 44th Edition, PSL 1, Table 6, Welded Pipe, Grade X42					60,200 minimum		42,100 min.	27 min.	

*The required minimum elongation specified in Table 3 of API STD. 5-L, 10th Edition is illegible on the available paper copy.

SPECIMEN IDENTIFICATION	TEST SPECIMEN DIMENSIONS			ULTIMATE STRESS		YIELD STRESS (0.5% OFFSET)		% ELONG. IN 2"	% R. IN A.
	DIAMETER/ WIDTH, in	THICKNESS, in	AREA, in^2	LOAD, lbf	STRESS, psi	LOAD, lbf	STRESS, psi		
Transverse - ERW Seam, Weld Flash Removed	0.245	0.288	0.0732	7,289	99,500	4,765	65,000	21**	
REQUIREMENTS									
API 5-L, 10th Edition, Table 3, Electric Welded, Open Hearth Steel, Grade B					60,000 minimum				
API 5L, 44th Edition, PSL 1, Table 6, Welded Pipe, Grade X42					60,200 minimum				

**Fractured through the base metal.

Transverse tensile test specimens were not flattened.

Test was performed using Instron Satec Systems tensile machine S/N 1189.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:

Josh Thomas
Laboratory Technician

DATE TESTED:

May 10, 2013

Joseph Eskew, C.W.I., Laboratory Services Manager

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

IMPACT TEST REPORT

TO:

ExxonMobil Pipeline Company

DATE OF RECEIPT:

April 16, 2013

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

P.O. NO.:

UCG/451007854

TEST METHOD:

Prepared per: ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 9.8
Tested per: ASTM A370-12a

LABORATORY TEST NO.:

CI0413062 - ERW

ACCEPTANCE CRITERION:

ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 9.8 and Table 8, PSL 2 Pipe, Grade ≤X60

IDENTIFICATION:

19' 10" long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

EFFECTIVE ENERGY:	SPECIMEN TYPE:	TEST TEMPERATURE:	SPECIMEN SIZE TESTED:
264 ft-lbf/358 Joules	Simple Beam, Type A	Various	10 mm x 5 mm

NO.	TEST TEMPERATURE	V-NOTCH LOCATION	IMPACT VALUES FOR SIZE TESTED, ft-lbf	LATERAL EXPANSION % Shear	LATERAL EXPANSION mils	REQUIREMENTS
1	Plus 95°F	ERW Seam Transverse	3	0	0	None Specified
2			2	0	1	
3			3	0	0	
1	Plus 80°F	ERW Seam Transverse	3	0	0	None Specified
2			2	0	0	
3			3	0	1	
1	Plus 65°F	ERW Seam Transverse	3	0	1	None Specified
2			2	0	0	
3			3	0	1	
1	Plus 32°F	ERW Seam Transverse	3	0	0	10 ft-lbf min. average energy 8 ft-lbf min. individual energy
2			3	0	0	
3			2	0	0	

Note that the CVN impact requirements are only specified for Type PSL 2 welded pipe, not Type PSL 1 welded pipe. No impact requirements are listed in the ASI STD 5-L, 10th Edition, August 1945.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY: Josh Thomas
Josh Thomas
Laboratory Technician

DATE TESTED:
May 1, 2013

Joseph Eskew
Joseph Eskew, C.W.I., Laboratory Services Manager

HMRL
HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

IMPACT TEST REPORT

TO:

ExxonMobil Pipeline Company

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

TEST METHOD:

Prepared per: ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 9.8
Tested per: ASTM A370-12a

DATE OF RECEIPT:

April 16, 2013

P.O. NO.:

UCG/451007854

LABORATORY TEST NO.:

CI0413062 - HAZ

ACCEPTANCE CRITERION:

ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 9.8 and Table 8, PSL 2 Pipe, Grade ≤X60

IDENTIFICATION:

19' 10" long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

EFFECTIVE ENERGY:	SPECIMEN TYPE:	TEST TEMPERATURE:	SPECIMEN SIZE TESTED:
264 ft-lbf/358 Joules	Simple Beam, Type A	Various	10 mm x 5 mm

NO.	TEST TEMPERATURE	V-NOTCH LOCATION	IMPACT VALUES FOR SIZE TESTED, ft-lbf	LATERAL EXPANSION % Shear	LATERAL EXPANSION mils	REQUIREMENTS
1	Plus 95°F	ERW Primary HAZ Transverse	3	0	3	None Specified
2			3	0	4	
3			4	5	6	
1	Plus 80°F	ERW Primary HAZ Transverse	5	5	7	None Specified
2			4	5	5	
3			8	5	5	
1	Plus 65°F	ERW Primary HAZ Transverse	3	0	2	None Specified
2			3	0	1	
3			5	0	2	
1	Plus 32°F	ERW Primary HAZ Transverse	4	0	0	10 ft-lbf min. average energy 8 ft-lbf min. individual energy
2			3	0	0	
3			4	0	0	

Note that the CVN impact requirements are only specified for Type PSL 2 welded pipe, not Type PSL 1 welded pipe. No impact requirements are listed in the ASI STD 5-L, 10th Edition, August 1945.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY: Josh Thomas
Josh Thomas
Laboratory Technician

DATE TESTED:
May 1, 2013

Joseph Eskew
Joseph Eskew, C.W.I., Laboratory Services Manager

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

IMPACT TEST REPORT

TO:

ExxonMobil Pipeline Company

SPECIFIED MATERIAL:

API STD. 5-L, 10th Edition, August 1945, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Welded Pipe, Grade X42

TEST METHOD:

Prepared per: ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 9.8
Tested per: ASTM A370-12a

DATE OF RECEIPT:

April 16, 2013

P.O. NO.:

UCG/451007854

LABORATORY TEST NO.:

CI0413062 - BM

ACCEPTANCE CRITERION:

ANSI/API Spec. 5L, 44th Edition, October 1, 2007, Section 9.8 and Table 8, PSL 2 Pipe, Grade ≤X60

IDENTIFICATION:

19' 10" long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

EFFECTIVE ENERGY:	SPECIMEN TYPE:	TEST TEMPERATURE:	SPECIMEN SIZE TESTED:
264 ft-lbf/358 Joules	Simple Beam, Type A	Various	10 mm x 5 mm

NO.	TEST TEMPERATURE	V-NOTCH LOCATION	IMPACT VALUES FOR SIZE TESTED, ft-lbf	LATERAL EXPANSION % Shear	LATERAL EXPANSION mils	REQUIREMENTS
1	Plus 95°F	Base Metal Transverse	10	15	16	None Specified
2			10	10	12	
3			10	10	14	
1	Plus 80°F	Base Metal Transverse	9	5	9	None Specified
2			9	5	10	
3			9	5	13	
1	Plus 65°F	Base Metal Transverse	10	5	13	None Specified
2			10	5	14	
3			10	5	13	
1	Plus 32°F	Base Metal Transverse	8	5	8	10 ft-lbf min. average energy 8 ft-lbf min. individual energy
2			9	5	12	
3			9	5	10	
1	0°F	Base Metal Transverse	5	0	1	None Specified
2			4	0	2	
1	Minus 32°F		2	0	0	

Note that the CVN impact requirements are only specified for Type PSL 2 welded pipe, not Type PSL 1 welded pipe. No impact requirements are listed in the ASI STD 5-L, 10th Edition, August 1945.

THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY: Josh Thomas
Josh Thomas
Laboratory Technician

DATE TESTED:
May 1, 2013

Joseph Eskew
Joseph Eskew, C.W.I., Laboratory Services Manager

HURST METALLURGICAL RESEARCH LABORATORY, INC.
2111 West Euless Boulevard (Highway 10), Euless, Texas 76040-6707
Phone (817) 283-4981, Metro 267-3421, Fax: Metro (817) 267-4234
Located in the Dallas/Fort Worth Metroplex

CHEMICAL ANALYSIS REPORT

TO:
ExxonMobil Pipeline Company

DATE OF RECEIPT:
April 16, 2013

SPECIFIED MATERIAL:
API STD. 5-L, 10th Edition, August 1945, Table 2, Electric Welded, Open Hearth Steel, Grade B, & ANSI/API Spec. 5L, 44th Edition, October 1, 2007, PSL 1, Table 4, Welded Pipe, Grade X42

P.O. NO.:
UCG/451007854

TEST METHOD:
ASTM E415-08

LABORATORY TEST NO.:
SP0413046

IDENTIFICATION:
19' 10" long Intact Section of a 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana Pegasus Crude Oil Pipeline after it Failed in Service in Mayflower, Arkansas; Installed in 1947 to 1948

ELEMENT WEIGHT %	Sample Tested		API 5-L, 10th Ed., Electric Weld Pipe, Open Hearth Steel, Grade B Spec.	API 5L, 44th Ed., PSL 1, Welded Pipe, Grade X42 Specification
Carbon[1]	0.30		0.30 max	0.26 max
Manganese	1.47		0.35 to 1.50	1.30 max
Phosphorus	0.017		0.045 max	0.030 max
Sulfur	0.031		0.06 max	0.030 max
Silicon	<0.01		[2]	[2]
Chromium	<0.01		[2]	0.50 max
Nickel	0.04		[2]	0.50 max
Molybdenum	<0.01		[2]	0.15 max
Copper	0.02		[2]	0.50 max
Aluminum	<0.01		[2]	[2]
Niobium	<0.01		[2]	[3]
Vanadium	<0.01		[2]	[3]
Titanium	<0.01		[2]	[3]
Iron	Base		Base	Base

REMARKS:

Material analyzed meets the chemical composition requirement for API 5L ERW pipe at the time the pipe was manufactured. However, it does not meet the above referenced current version of API 5L for ERW pipe, in accordance with the above referenced acceptance criterion.

[1]Test performed by HurstLab approved supplier and the results are outside the scope of accreditation for tests listed in A2LA Cert. #3152.01 and not covered by this accreditation.
[2]Analytical range not specified for element.
[3]Sum of Niobium + Vanadium + Tantalum = 0.15% maximum

Test was performed using Thermo Jarrell Ash AtomComp 81, S/N 26094 Optical Emission Spectrometer with Angstrom S-1000 readout and control system.

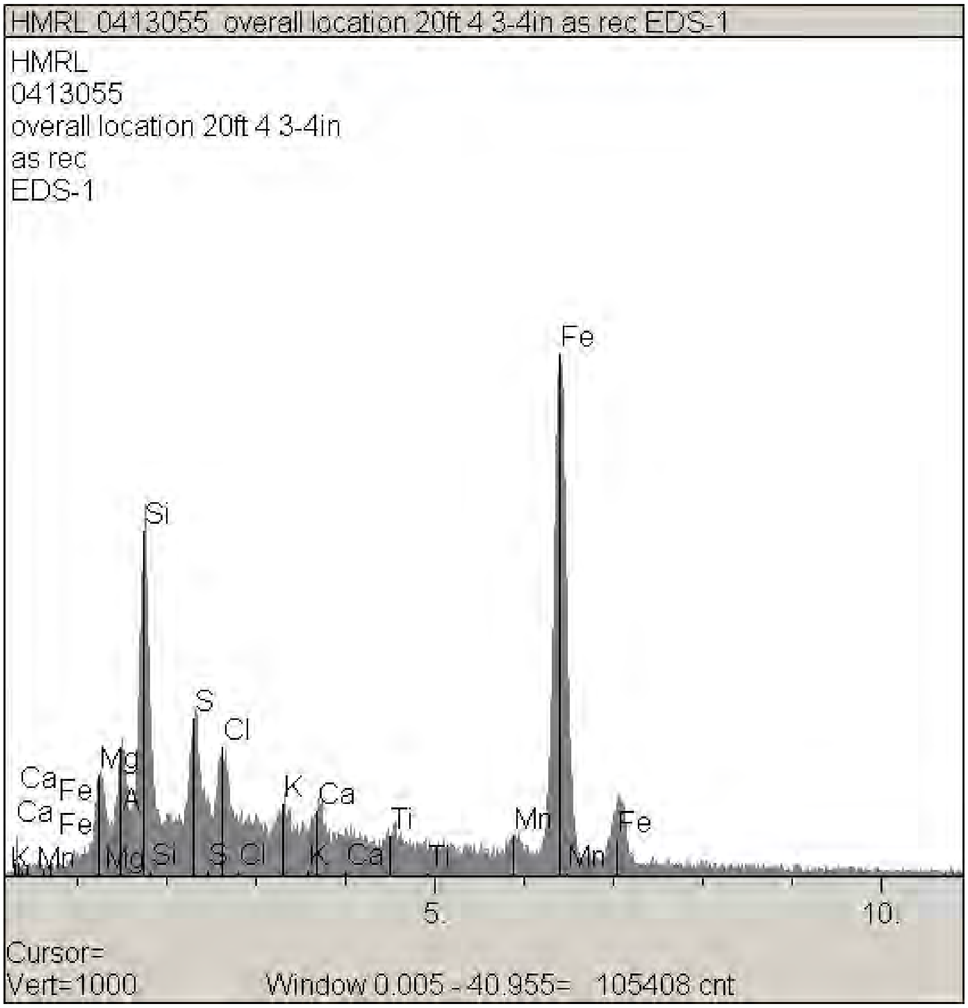
THIS IS TO CERTIFY THAT THE ABOVE ARE THE ACTUAL RESULTS OF THE SUBMITTED SAMPLE(S) PREPARED AND TESTED IN ACCORDANCE WITH THE REQUIREMENTS OF THE APPLICABLE SPECIFICATION(S), THE HMRL Q.A. MANUAL, FIFTH EDITION AND ITS IMPLEMENTING PROCEDURES, AS APPLICABLE.

TESTED BY:
Brad Shepard, Chemist

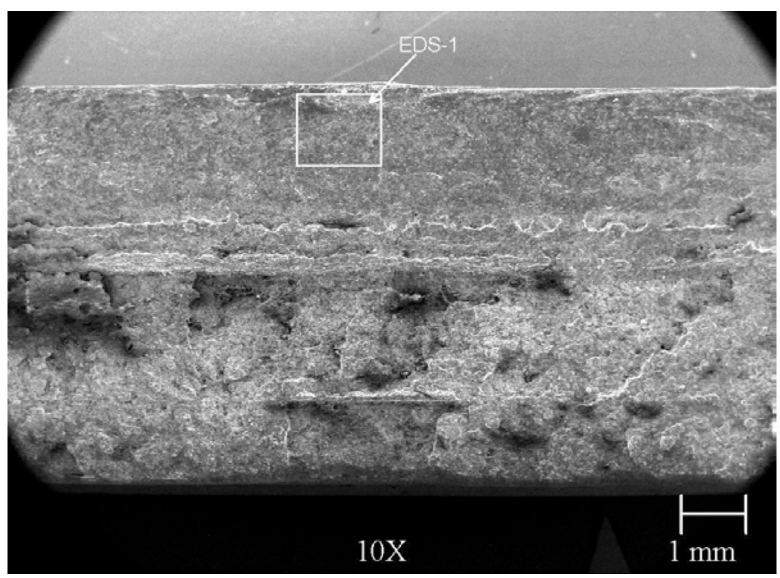
DATE TESTED:
May 3, 2013

Joseph Eskew, C.W.I., Laboratory Services Manager

Table 16

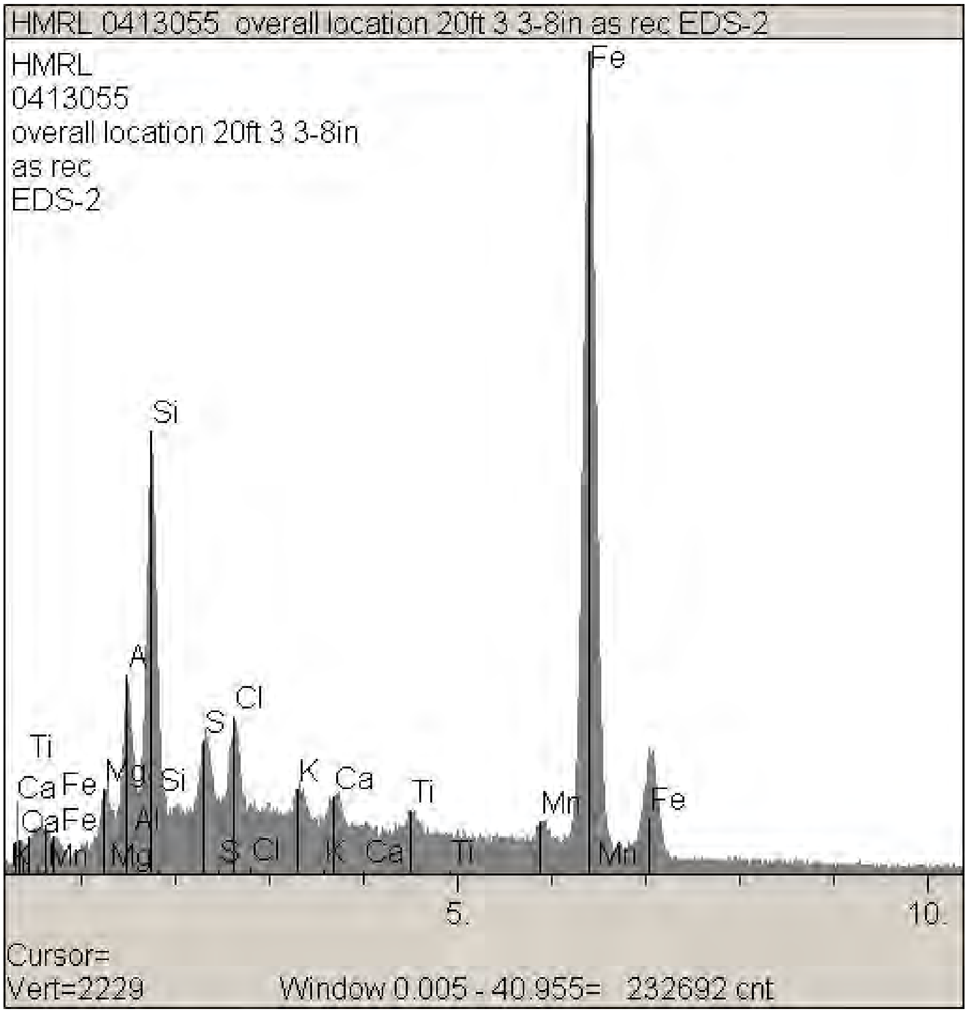


Elt.	Line	Intensity (c/s)	Error 2-sig	Conc, wt%
Mg	Ka	5.08	0.336	3.980
Al	Ka	5.50	0.350	3.484
Si	Ka	24.23	0.734	12.974
S	Ka	9.02	0.448	4.081
Cl	Ka	6.15	0.370	2.794
K	Ka	2.17	0.219	0.975
Ca	Ka	2.52	0.237	1.162
Ti	Ka	1.40	0.176	0.810
Mn	Ka	1.96	0.209	1.603
Fe	Ka	57.94	1.135	68.137
			Total	100.000

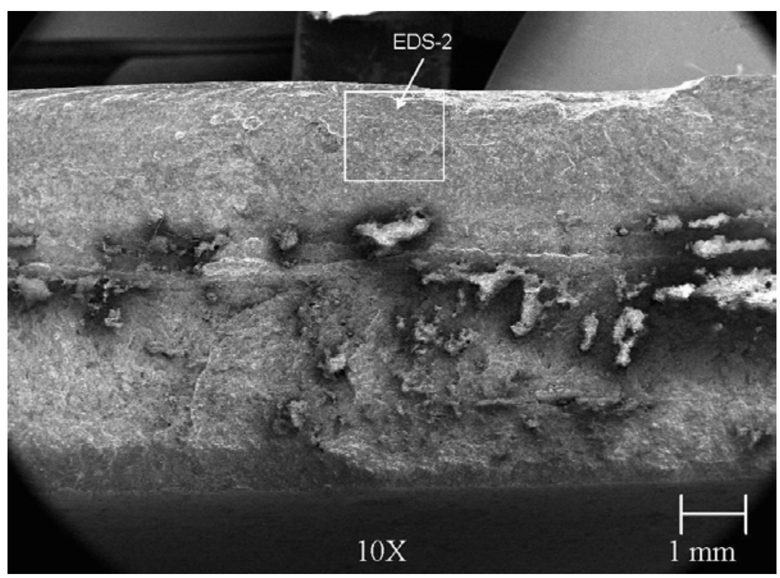


kV 15.0
Takeoff Angle 15.0˚
Elapsed Livetime 180.0

It should be noted that EDS analysis is a semi-quantitative test method and was used due to the extremely small sample size. The data obtained should not be used at face value, but only as comparative relative values only. The EDS analysis was performed by an HMRL approved supplier.

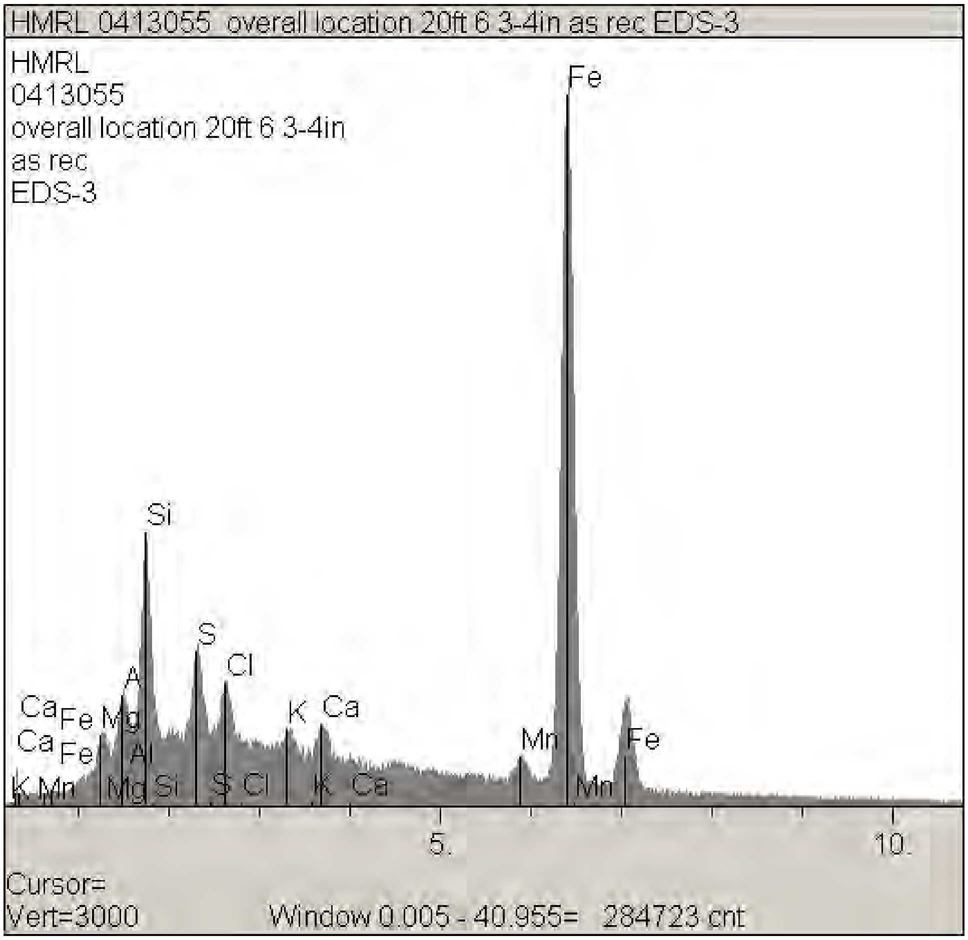


Elt.	Line	Intensity (c/s)	Error 2-sig	Conc, wt.%
Mg	Ka	7.65	0.412	1.925
Al	Ka	24.16	0.733	4.776
Si	Ka	71.09	1.257	12.032
S	Ka	15.28	0.583	2.144
Cl	Ka	17.20	0.618	2.377
K	Ka	6.45	0.379	0.883
Ca	Ka	6.23	0.372	0.874
Ti	Ka	4.76	0.325	0.836
Mn	Ka	4.33	0.310	1.056
Fe	Ka	202.41	2.121	73.097
			Total	100.000



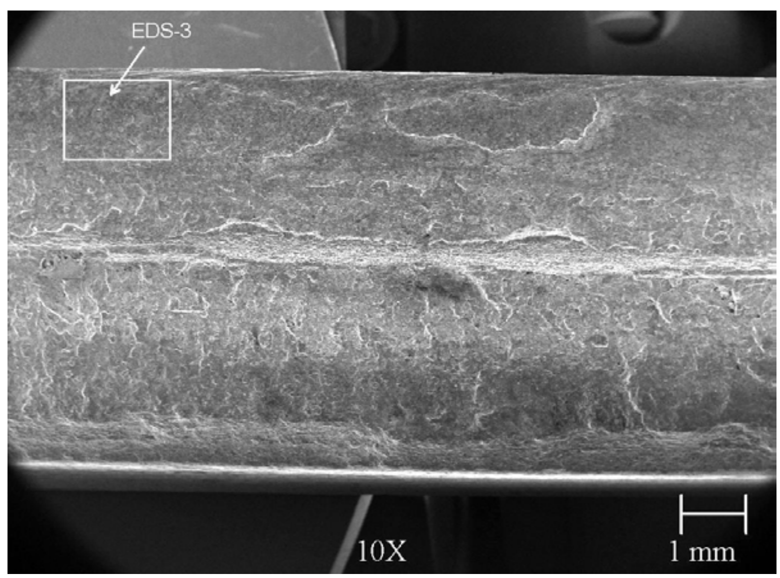
kV 15.0
Takeoff Angle 15.0°
Elapsed Livetime 180.0

It should be noted that EDS analysis is a semi-quantitative test method and was used due to the extremely small sample size. The data obtained should not be used at face value, but only as comparative relative values only. The EDS analysis was performed by an HMRL approved supplier.



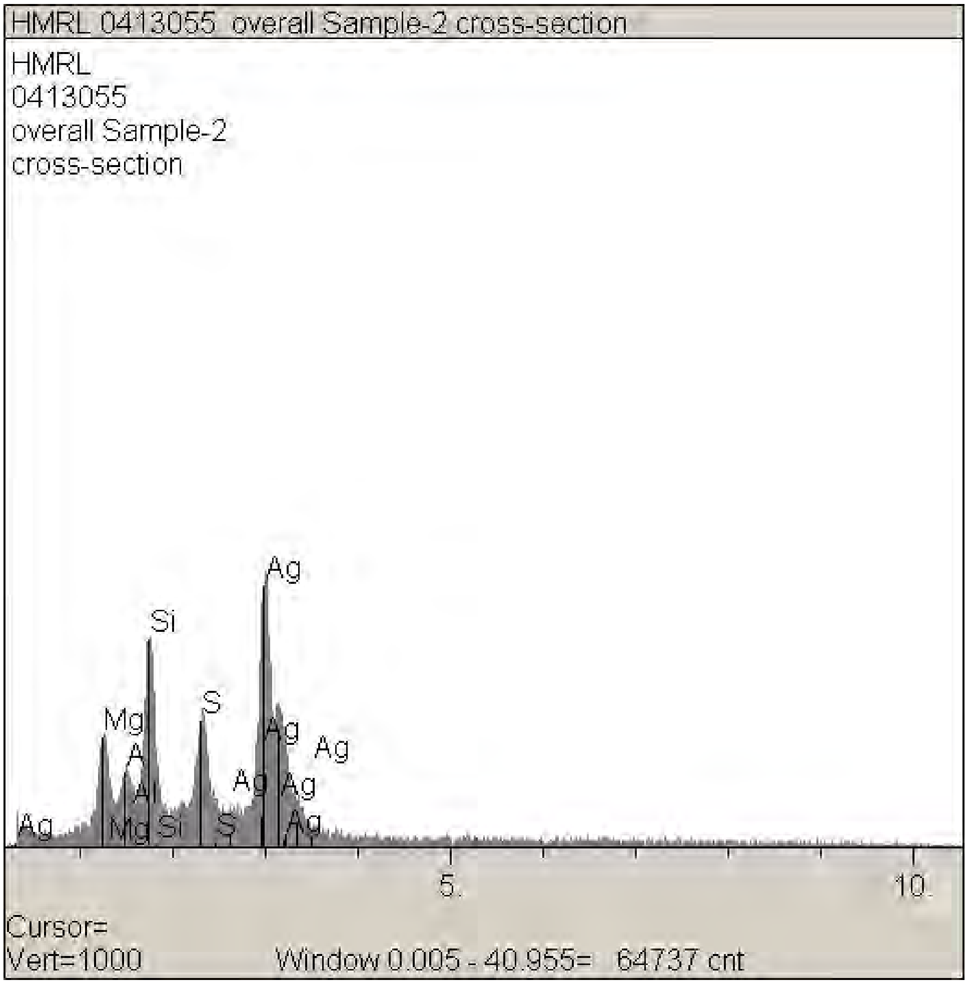
Elt.	Line	Intensity (c/s)	Error 2-sig	Conc, wt%
Mg	Ka	9.35	0.456	2.084
Al	Ka	17.90	0.631	3.118
Si	Ka	59.13	1.146	8.578
S	Ka	25.86	0.758	3.006
Cl	Ka	16.11	0.598	1.864
K	Ka	6.10	0.368	0.698
Ca	Ka	10.23	0.477	1.198
Mn	Ka	7.75	0.415	1.541
Fe	Ka	256.66	2.388	77.912
			Total	100.000

kV 15.0
Takeoff Angle 15.0°
Elapsed Livetime 180.0

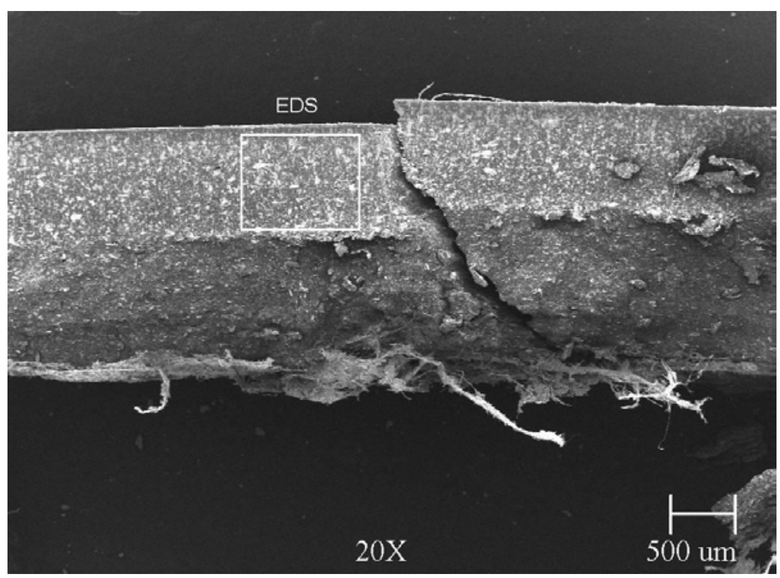


It should be noted that EDS analysis is a semi-quantitative test method and was used due to the extremely small sample size. The data obtained should not be used at face value, but only as comparative relative values only. The EDS analysis was performed by an HMRL approved supplier.

Table 19

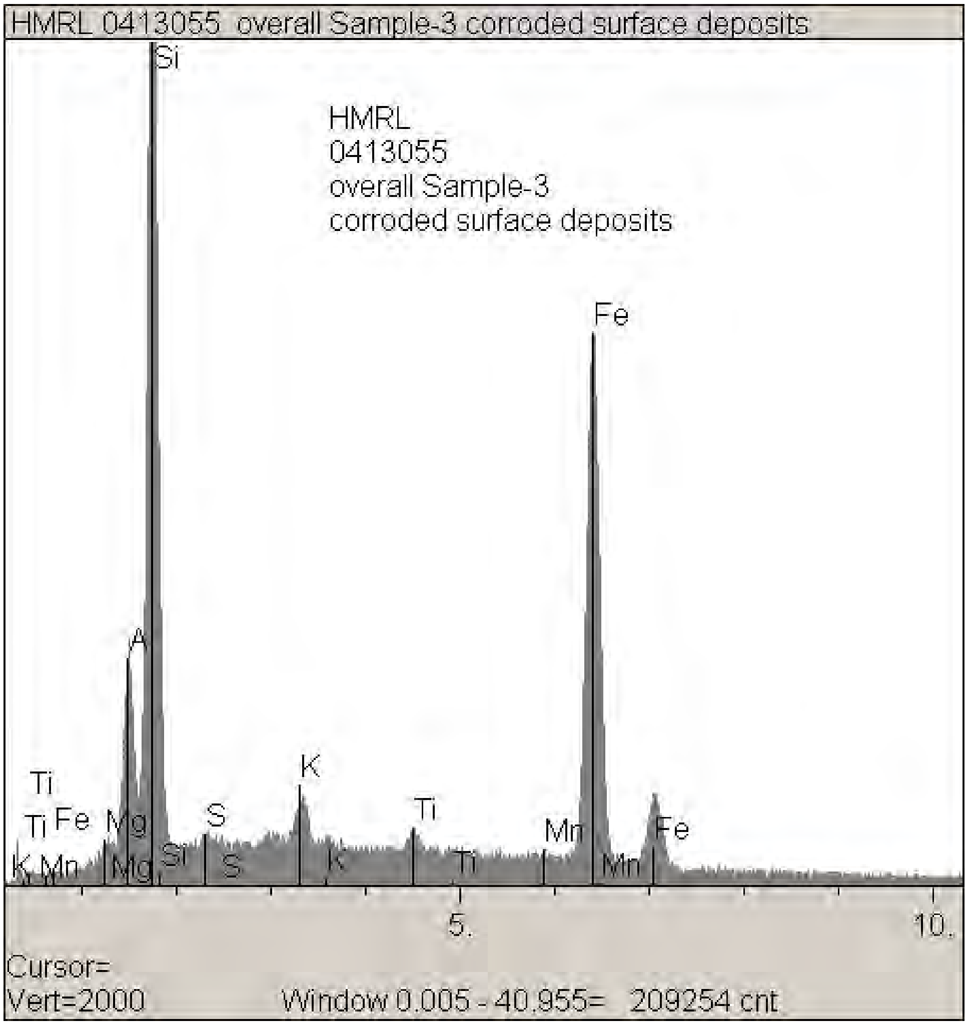


Elt.	Line	Intensity (c/s)	Error 2-sig	Conc, wt.%
Mg	Ka	6.51	0.380	14.522
Al	Ka	2.48	0.235	6.942
Si	Ka	14.98	0.577	42.773
S	Ka	9.15	0.451	35.763
Ag	La	0.00	0.000	0.000
			Total	100.000

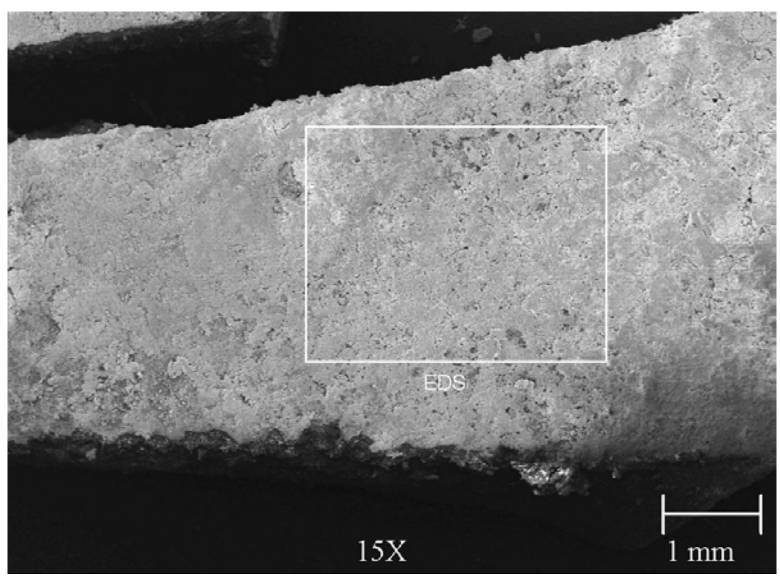


kV 15.0
Takeoff Angle 15.0˚
Elapsed Livetime 180.0

It should be noted that EDS analysis is a semi-quantitative test method and was used due to the extremely small sample size. The data obtained should not be used at face value, but only as comparative relative values only. The EDS analysis was performed by an HMRL approved supplier.



Elt.	Line	Intensity (c/s)	Error 2-sig	Conc, wt.%
Mg	Ka	1.61	0.189	0.417
Al	Ka	33.01	0.856	6.783
Si	Ka	178.83	1.993	33.882
S	Ka	1.97	0.209	0.391
K	Ka	9.34	0.456	1.679
Ti	Ka	4.09	0.301	0.949
Mn	Ka	0.91	0.142	0.306
Fe	Ka	120.34	1.635	55.594
			Total	100.000



kV 15.0
Takeoff Angle 15.0°
Elapsed Livetime 180.0

It should be noted that EDS analysis is a semi-quantitative test method and was used due to the extremely small sample size. The data obtained should not be used at face value, but only as comparative relative values only. The EDS analysis was performed by an HMRL approved supplier.

Appendix I

PEGASUS LINE - CONWAY TO CORSICANA M.P. 314.77

MECHANICAL AND METALLURGICAL TESTING AND FAILURE ANALYSIS PROTOCOL

I. Objective: Perform mechanical and metallurgical testing and failure analysis of the failed pipe from the Affected Pipeline in the area of Mayflower, Arkansas pursuant to this protocol.

II. Background Information/Additional Requirements:

A. Pipe manufactured by Youngstown Sheet and Tube and installed in 1947-1948.

B. Grade API 5LX-42 (42,000 psi SMYS) Low Frequency DC ERW, 20" x 0.312" wall.

C. Pipe joint has been coated and cathodically protected since original construction.

D. Crude oil service from1947 to December 2002 when it was purged and idled with nitrogen. The line was the re-hydrotested and put back in crude service in 2006 to present.

E. The 2006 hydrostatic test pressure for the specimen was 1082 psig, and the corresponding pressure at time of failure was estimated at 708 psig.

F. Upon excavation, the pipe specimen shall be delivered to Hurst Metallurgical Research Laboratory, Inc. (Hurst Lab) at:
2111 West Euless Blvd. Euless,
TX 76040
Attn: Mahesh J. Madhani
817-283-4981

G. Prior to commencing the mechanical and metallurgical testing described herein, the Director of PHMSA Southwest Region shall be provided with the scheduled dates, times, and locations of the testing to allow a PHMSA representative to witness the testing.

H. All relevant pipe remnants (not consumed in process) will be preserved and stored in a secure location until returned to EMPCo. No material related to failed pipe will be disposed or scrapped by Hurst Lab.

I. All resulting reports in their entirety (including all media), whether draft or final, shall be distributed to EMPCo and the Director of PHMSA Southwest Region at the same time.

J. Attached is the Metallurgical Laboratory Failure Examination Protocol (05/08/2007) provided by PHMSA. Attachment 1 to PHMSA's protocol provides guidelines for custody transfer and transportation of physical evidence. Attachment 2 to PHMSA's protocol provides a worksheet for documenting physical measurements. These data collection forms should be used, and if not, ensure that the applicable information contained in those examples is recorded during the testing of the failed pipe.

K. Specimen Identification

1. A 34' Long Section of a failed 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana segment of the Pegasus Crude Oil Pipeline after it failed in operation in Mayflower, Arkansas. Installed in 1947 to 1948

2. A 19'-10" Long Section of an intact 20" O.D. x 0.312" wall Pipe; Removed from Milepost 314.77 in the Conway to Corsicana segment of the Pegasus Crude Oil Pipeline . Installed in 1947 to 1948

III. Proposed Tests:

A. Visual and Nondestructive Examination

1. Photographically document the pipe segments in the as-received condition. Provide photos of the failed specimens indicating 12:00 o'clock position at top of pipe, milepost, and north/south ends of pipe section as installed in the pipeline. Further, this documentation should include, but is not limited to, the following:
a) Fracture face and area adjacent to fracture
b) Coating condition
c) Manufacturing flaws
d) Pitting and/or any evidence of internal/external corrosion
e) Cracks
f) Seams
g) Girth welds
h) Determine and mark the location of the electric resistance weld seam at end of each sample and determine if the failure falls within the electric resistance weld zone.
i) Record any markings detected on the inside and outside surfaces of the pipe.

2. Perform visual inspection on "as-received" condition and document any anomalies, including but not limited to the following:
a) Cracks and crevices
b) Condition of the ERW seam and girth weld
c) Dents, bends, and buckles
d) Gouges
e) Manufacturing defects

f) Coating condition, and any damages such as wrinkles or tents, or disbonding
g) Pitting and/or any evidence of internal/external corrosion
h) Evidence of arc burns and excessive grinding
i) Presence of corrosion deposits
j) Describe coating, and coating damage (disbonding) if any, in the vicinity of the fracture origin and at other locations in the failed pipe sample

3. Collect solid and liquid samples, if present, from the pipe surface and conduct chemical analysis and microbial tests on these samples as appropriate. Examples of these samples that may be collected are, but are not limited to, the following:
a) Liquid accumulated underneath the coating
b) Corrosion products from the interior/exterior surfaces of the pipe
c) Soil adhering to the pipe not contaminated by the crude release

4. The coating on the surfaces of the pipes will be removed by a third party, contracted directly by EMPCo. The coating shall be removed in such a manner that it will not be injurious to the pipe. Photographically document and visually inspect the pipe again following coating removal, as necessary, (see 1. and 2. above for guidance). Note any disbondment or possible adhesion problems with coating.

Attachment 2 to PHMSA's protocol provides a worksheet for documenting physical measurements.

EMPCo's proposed coating removal procedure/JSA document is provided as a supplement to this protocol. This document was previously provided to PHMSA to address coating removal; for the pipe extraction work. Extreme care will be taken to prevent any permanent mechanical damage to the pipe section. The use of a resin hammer will be initially used on a non-fractured intact pipe to remove the coating. If removal of the coating is not possible by the use of a resin hammer, a steel hammer may be used. The removal of the coating will be observed by Hurst Lab personnel. In addition, a meeting will be held with the coating removal team prior to the removal of the coating to instruct the personnel that the integrity of the pipe is maintained. A representative of Hurst Lab will be present to monitor coating removal in its entirety.

B. Physical Measurements

1. Verify roundness and geometry of pipe at the extremities and closer to the failed surface.

2. Perform a "map" of ultrasonic thickness measurements within 12 inches upstream and downstream of each end of the rupture if possible, and along the entire length of the rupture. Measurements will be taken around the entire circumference along the length of the pipe as specified. At each 2" interval, measurements will be taken at 30 locations evenly spaced around the circumference of the pipe. The ultrasonic tests shall be conducted at this Hurst Lab by Bonded Inspections, Inc.

3. Various dimensions of the fractured and intact pipes will be measured using micrometers or other suitable measuring devices. Measurements will include but are not limited to such as:
a) Diameter and wall thickness at areas adjacent to the failure, as well as visually intact areas of the pipe
b) The length of any cracks or ruptures
c) Axial distance from crack origins and/or tips to the nearest girth weld

C. <u>Chemical Analysis</u>

1. Chemical analysis of the pipe shall be performed using the Optical Emission Spectroscopic (OES) test method in accordance with ASTM E415-08, to determine the weight percent (wt%) of carbon, manganese, phosphorus, sulfur, silicon, chromium, nickel, molybdenum, copper, and aluminum, as well as any other elements common to API 5L line pipe steels.

Note: Both the latest edition of API 5L and the edition in effect at the time of manufacture shall be referenced as the standard for comparison.

D. <u>Mechanical Properties</u>

1. Mechanical testing involving yield strength, ultimate tensile strength, and elongation should be performed on pipe material that has not been plastically deformed during service. These tests will be performed in accordance with ASTM A370-12a for the pipe base metal and weld seams.

2. The transverse tensile test specimen blanks will be flattened prior to machining and testing, as allowed in API 5L. All tensile test specimens will be 1-
1/2" wide over the 2" long gauge area, and the yield stress will be calculated at a 0.5% offset. The minimum specimens that shall be prepared and tested are as follows:
a) 1 transverse test specimen, removed through the ERW

seam b) 1 transverse test specimen, removed 90o from the

ERW seam correct

c) 1 transverse test specimen, removed 180° from the ERW seam
d) 1 longitudinal test specimen, removed 90° from the ERW seam
Note: Both the latest edition of API 5L and the edition in effect at the time of manufacture shall be referenced as the standard for comparison.

3. Impact Tests
For Charpy V-notch (CVN) impact testing, testing should be performed in accordance with ASTM A370-12a to determine the toughness characteristics of the ERW seam and the base metal of the pipe. Multiple sets of 3 transverse 10 mm x 6.67 mm (2/3 size) or 10 mm x 5 mm (1/2 size) CVN impact test specimens will be prepared and tested at various temperatures to establish the

upper-shelf energy (in ft-lbf), the lower-shelf energy (in ft-lbf), and the ductile- to-brittle transition temperature for the base metal and, if possible, the ERW seam. The lateral expansion (in mils) and the percent shear will also be reported. CVN impact values used to develop the S-curve will be provided down to a minimum temperature of 32°F. Minimum operating temperature of the pipeline during winter months could be 45 degrees F in extreme cases. Therefore, it is preferable to have the CVN values (S-curve) down to 32°F provided. Longitudinal CVN values are not needed unless specifically asked for.

It should be noted that representative CVN impact values for the ERW seam may be difficult to obtain, and that the values can vary considerably throughout the welded joint and along the pipe.

Note: Both the latest edition of API 5L and the edition in effect at the time of manufacture shall be referenced as the standard for comparison.

E. Metallographic Examinations

1. Perform metallographic examination and take photomicrographs of areas such as the following:
a) At or near the fracture origin
b) Fracture surface
c) Weld seams
d) Areas identified as defects or cracks during visual and/or nondestructive examination
e) Areas away from the fracture surface showing typical microstructures of the base metal, weld metal, and heat-affected zone

2. Metallographic samples should be examined to validate any issues specific to the failure such as the following: pipe grade, weld seam in area of fracture, weld seam in unaffected area, corrosion, and indication of outside mechanical damage.

F. <u>Microhardness Surveys</u>

1. Perform Knoop microhardness profiles at areas at or near the fracture origin and the weld seam (converted to Brinell hardness values). Microhardness surveys shall be conducted on metallographically prepared cross-sections in accordance with ASTM E384-11, to determine the hardness at appropriate locations such as the base metal, heat affected zone, and fusion line of the ERW seam at the fracture origin and away from the fracture.

G. <u>Fractographic Examination</u>

1. Visually examine the fracture surface in detail to identify the characteristics of the fracture, the nature of the original defect, and the failure initiation point(s).

2. Sections of the fracture surfaces will be removed as necessary to allow for detailed low magnification visual examination and photographic documentation of the fracture morphology. If possible, the fracture will be determined to be the result of brittle or ductile overload, fatigue propagated cracking, or the result of combined effects of stress and environment.

3. If necessary, small sections of the fracture surface at pertinent areas will be examined and photographed at high magnification using a Scanning Electron Microscope (SEM) by Anastas Technical Services in Houston, TX.

H. Corrosion Examination

1. Surface deposits and residues associated with the fracture area and adjacent areas should be collected and analyzed, if possible, to characterize and determine the origin of the deposits. Attachment 2 to PHMSA's protocol provides a worksheet for documenting chemical analysis results of corrosion products.

2. Based on the results of the visual, non-destructive, and metallographic examinations, the presence of corrosion should be documented, and the type and characteristics of any corrosion present should be evaluated. Remaining strength calculations (RSTRENG/ASME B31G) may be performed on corroded areas to support the failure investigation.

3. If an in-line inspection (ILI) tool has inspected the failure site in the past, investigation of the ILI log and report can provide information relevant to corrosion growth rate. The operator may not have this information immediately available, but it may be desirable to do this research. In the case of finding the anomaly present in the past ILI report, it is important to understand the operator's excavation criteria in effect at the time of the ILI and the application of RSTRENG calculations and anomaly interaction criteria.

I. Data Analysis and Report Publication

1. Data analysis will include a review of the provided background and service history, if available, analysis of the test data generated through the aforementioned tests and evaluations, the review of the available standards and specifications applicable to the pipe, and metallurgical research.

2. Both the latest edition of API 5L (45th Edition) and the edition in effect at the time the pipe was manufactured (10th Edition) will be referenced as standards for comparison. For the purposes of identifying test specimens, the longitudinal direction will be considered to be along the axis of the pipe.

3. The final report containing our findings will then be published to the agreed-upon parties.

Appendix II

The photograph displays the pipe sections in the as-received condition with the protective wrapping on the outside surface of the pipe sections that was applied to prevent any damage during transportation.

The photographs display two (2) perspective views of the pipe section in the as-received condition.

The photograph displays the pipe section, a drum containing the coating material that was removed in the field prior to sectioning of the cracked pipe and a bag containing possible calcareous deposit.

The photographs display two (2) pipe sections during the unloading process. There was no evidence of any transportation related damage to the pipe sections.

THIS MEMORANDUM is an acknowledgment that a Bill of Lading has been issued and is not the Original Bill of Lading, nor a copy or duplicate, covering the property named herein, and is intended solely for filing or record

Shipper's No. ______

(Carrier) ______ SCAC. ______ Carrier's No. ______

Received, subject to the classifications and tariffs in effect on the date of the Bill of Lading:

at ______, date ______ from ______

the property described below, in apparent good order, except as noted (contents and condition of contents of packages unknown), marked, consigned, and destined as indicated below, which said company (the word company being understood throughout this contract as meaning any person or corporation in possession of the property under the contract) agrees to carry to its usual place of delivery at said destination, if on its own road or its own water line, otherwise to deliver to another carrier on the route to said destination. It is mutually agreed, as to each carrier of all or any portion of said destination, and as to each party at the time interested in any or all of said property, that every service to be performed hereunder shall be subject to all the conditions not prohibited by law, whether printed or written, herein contained (as specified in Appendix B to Part 1035) which are hereby agreed to by the shipper and accepted for himself and his assigns.

TO: (Mail or street address of consignee for purposes of notification only)
Consignee Hurst Metallurgical
Street 2111 WEST Euless Blvd (Hwy 10
Destination HURST TX Zip

FROM: Mayflower + Conway to Hou
Shipper
Street Mob + Cixxoih
Origin Conway Ark Zip

Route:

Delivering Carrier: Trailer Initial/Number: U.S. DOT Hazmat Reg. Number

No. of Packages	HM	Description of articles, special marks, and exceptions	Hazard Class	I.D. Number	Packing Group	*Weight (subject to correction)	Class or Rate	Labels Required (or exemption)	Check Column
2		Pipes & ~~1 Bag Dirt~~							
1		55 gallon drain							
1		Bag Dirt							

Remit C.O.D. to:
Address:
City: State: Zip:

Subject to Section 7 of conditions, if this shipment is to be delivered to consignee without recourse on the consignor, the consignor shall sign the following statement:
The carrier shall not make delivery of this shipment without payment of freight and all other lawful charges.

(Signature of Consignor)

C.O.D. Amount: $

C.O.D. Fee Prepaid ☐ Collect ☐ $

Charges Advanced $

Freight Charges Prepaid ☐ Collect ☐

*If the shipment moves between two ports by a carrier by water, the law requires that the bill of lading shall state whether it is "carrier's or shipper's weight".
Note— where the rate is dependent on value, shippers are required to state specifically in writing the agreed or declared value of the property.
The agreed or declared value of the property is hereby specifically stated by the shipper to be not exceeding ______ per ______

This is to certify that the above-named materials are properly classified, described, packaged, marked and labeled and are in proper condition for transportation according to the applicable regulations of the Department of Transportation.

per ______

PLACARDS REQUIRED

PLACARDS SUPPLIED ☐ YES ☐ NO—FURNISHED BY CARRIER

DRIVER'S SIGNATURE:

SHIPPER: ______
PER: Rec'd DATE:
NMalham 4/16/2013

CARRIER: Armstrong
PER: DATE: 4-16-13

EMERGENCY RESPONSE TELEPHONE NUMBER: ( )

Monitored at all times the Hazardous Material is in transportation including storage incidental to transportation (§172.604)

Permanent post office address of shipper

RPBOL-25 (rev. 900211) *Published by RoadPro*

Attachment C

Evidence Control Log

ExxonMobil Pipeline Company
Pegasus Pipeline, Mayflower, AR

Tag #	Date Recovered	Description	Photo #
2	4/15/2013	South of Damaged Section Pipe ~20'	100-0320 278

Date	Action (eg. Shipped, returned, testing, etc.)	Destination	Person/Organization	Signatures
4/15	X-fer	Conway Station	T. Armstrong Trucking	Released: KDM [signature]
				Accepted: [signature]
				Released: MITCH WILSON
				Accepted:
4/15	X-fer	Conway Station	Ed Fletcher	Released: [signature]
			Security	Accepted: [signature]
4/16	X-fer	Conway Station	Frankie Tucker	Released: [signature]
			Security	Accepted: [signature]
4/16	X-fer	Conway Station	T. Armstrong Trucking	Released: [signature]
				Accepted: [signature] Young
			4/16/2013	Released:
			3:30PM M. J. MADHANI	Accepted: [signature]
				Released:
				Accepted:
				Released:
				Accepted:

Attachment C

Evidence Control Log

ExxonMobil Pipeline Company
Pegasus Pipeline, Mayflower, AR

Tag #	Date Recovered	Description	Photo #
4	4/14/2013	Pipe Coating in Black Barrel	

Date	Action (eg. Shipped, returned, testing, etc.)	Destination	Person/Organization	Signatures
4/16	Shipped	Hurst Lab	J. Armstrong Trucking	Released: [illegible] KDM
			C. Young	Accepted: C. Young
				Released:
				Accepted:
4/16	Received	Hurst Lab	X	Released:
		4/16/2013 3:30PM	M. J. MADHANI	Accepted: X MJMadhani
				Released:
				Accepted:
				Released:
				Accepted:
				Released:
				Accepted:
				Released:
				Accepted:
				Released:
				Accepted:

Attachment C

Evidence Control Log

ExxonMobil Pipeline Company
Pegasus Pipeline, Mayflower, AR

Tag #	Date Recovered	Description	Photo #
3	4/15/2013	Surface Deposit	100-0315 273

Date	Action (eg. Shipped, returned, testing, etc.)	Destination	Person/Organization	Signatures
4/15	X-fer	Conway Station	T. Armstrong Trucking	Released: KDM [signature]
				Accepted: [signature]
				Released: MITCH WKSN
				Accepted:
4/15	X-fer	Conway Station	EP Fletcher	Released: [signature]
			Security	Accepted: [signature]
4/16	X-fer	Conway Station	Frankie Tucker	Released: [signature]
			Security	Accepted: [signature]
4/16	X-fer	Conway Station	T Armstrong Trucking	Released: [signature]
				Accepted: C. Young
			4/16/2013	Released:
			3:30PM MG Madhani	Accepted: [signature]
				Released:
				Accepted:
				Released:
				Accepted:

Attachment C

Evidence Control Log

ExxonMobil Pipeline Company
Pegasus Pipeline, Mayflower, AR

Tag #	Date Recovered	Description	Photo #
1	4/15/2013	Damaged Joint ~34'	100-0319 277

Date	Action (eg. Shipped, returned, testing, etc.)	Destination	Person/Organization	Signatures
4/15	X-fer	Conway Station	T. Armstrong Trucking	Released: KDM
				Accepted:
				Released: MITCH WILSON
				Accepted:
4/15	X-fer	Conway Station	Ed Fletcher	Released:
			Security	Accepted:
4/16	X-fer	Conway Station	Frankie Tucker	Released:
			Security	Accepted: J.J. Tuck
4-16	X-fer	Conway Station	T. Armstrong Truck	Released: J.J. Tuck
				Accepted: J.C. Young
			4/16/2013 3:30PM	Released:
			MJ MADHANI	Accepted: MJMadhani
				Released:
				Accepted:
				Released:
				Accepted:

Appendix III

COATING REMOVAL TASK

Extreme care will be taken to prevent any permanent mechanical damage to the pipe section. The use of a resin hammer will be initially used on a non-fractured intact pipe to remove the coating. If removal of the coating is not possible by the use of a resin hammer, a steel hammer may be used. The removal of the coating will be observed by HurstLab personnel. In addition, a meeting will be held with the coating removal team prior to the removal of the coating to instruct the personnel.

The undersigned understands the importance of using extreme care in removing the pipe coating.

Print Name	Signature	Date
Argenis Hernandez	Argenis H[illegible]	4-22-13
Federico Olvera	Federico Olvera	4-22-13
Ausencio Comisario	Ausencio [illegible]	4-22-13
Laureano Mirafuentes	L. Mirafuentes	4-22-13
Billy C. Hartley	[illegible]	4-22-13

The photographs display the coating removal that was carried by impacting with steel or composite hammers.

The photographs display the hand removal process of the coating which remained on the pipe after initial removal with hammer.

The photograph displays the initial coating removal process.

The photograph displays the careful hand removal process of the coating adjacent to the crack.

Appendix IV

SGS PIINDE Pipeline Integrity Specialists

ExxonMobil Pipeline

Inline Inspection Tool Correlation NDE Report

GE (PII/TFI) / Run Date: July 2012

US Reference:	**16310+25.62**	ODO to U/S GW:	**81602.14**
Distance to US Reference:	4501.09		
ODO to Primary Anomaly 81627.98	Dig # 12	Upstream Girth Weld #: **17290**	

Project: **HURST LAB EVALUATION**

Pipe Description / Nominals: (**20.000" 0.312" X42**)

Segment: **Conway to Corsica**

	U/S Joint	Anomaly Joint	D/S Joint
Joint Length:	NA	NA	NA
LS Circ Position:	0°	360°	0°

Inspection Area Dimensions

Length of Pipe Examined: 24.67'

Axial Start: -1.00' End: 23.67'

Circ Start: 0° End: 360°

Conditions:

Soil pH NA

Top of Ditch P-S NA

Btm of Ditch P-S NA

Soil Resistivity na ohm/cm

Seam Type: SAW [ ] FW [ ] ERW [X] DSAW [ ] SMLS [ ] Lap [ ]

Coating Type: Tape [ ] FBE [ ] Coal Tar [X]

Actual Profile Data: T1 316 T2 312 TW 383 WW 520 WH 0

NDE Methods

Visual [X] WCAMT [ ] UT-FAST [ ] UT-0 Degree [X] UT-Shear [ ] UT- Phased Array [ ]

Anomaly Information

	Log Start (ft)	Log length (in)	Log circ start (°)	Log circ extent (in)	Log Depth (%)	Start of Ind (ft)	End of Ind (ft)	Axial Length of Ind (in)	Circ start (°)	Circ end (°)	Circ extent (in)	Pipe Thk at Ind (mils)	Max Ind Depth (mils)	Depth, Max %	Pipe or weld	ID, OD or Mid	Flaw Type	Grind Length (in)	NDE Method	NDE Comments or Remarks
1						4.12	4.72	7.2	195	197	0.3	313	153	48.9%	Pipe	MID	Incl	NA	UT	See Remarks Below
2																				
3																				
4																				
5																				

NG=Not Given NV= Not Verified NA= Not Applicable VI= Verified by Dig Inspector

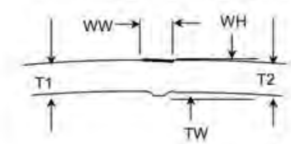
NDE Remarks:

CMAPPs (AUT) ultrasonic thickness measurements were taken from 12 inches upstream of the girth weld and from 12 inches downstream of the rupture for 360 degrees around the pipe surface. In addition, CMAPPs thickness measurements were also taken around the entire circumference along the length of pipe where surface conditions allowed meaningful measurements to be recorded.

No internal corrosion areas were indentified during the ultrasonic examination.

Anomaly 1 appears to be a laminar-type inclusion in the pipe wall.

Thickness Profile of Long Seam



Repair Type:	Sleeve Number 1	Start:	End:
Repair Type:	Sleeve Number 2	Start:	End:

A = Type "A" sleeve; B = Type "B" Sleeve; C = Clockspring; N = No repair required

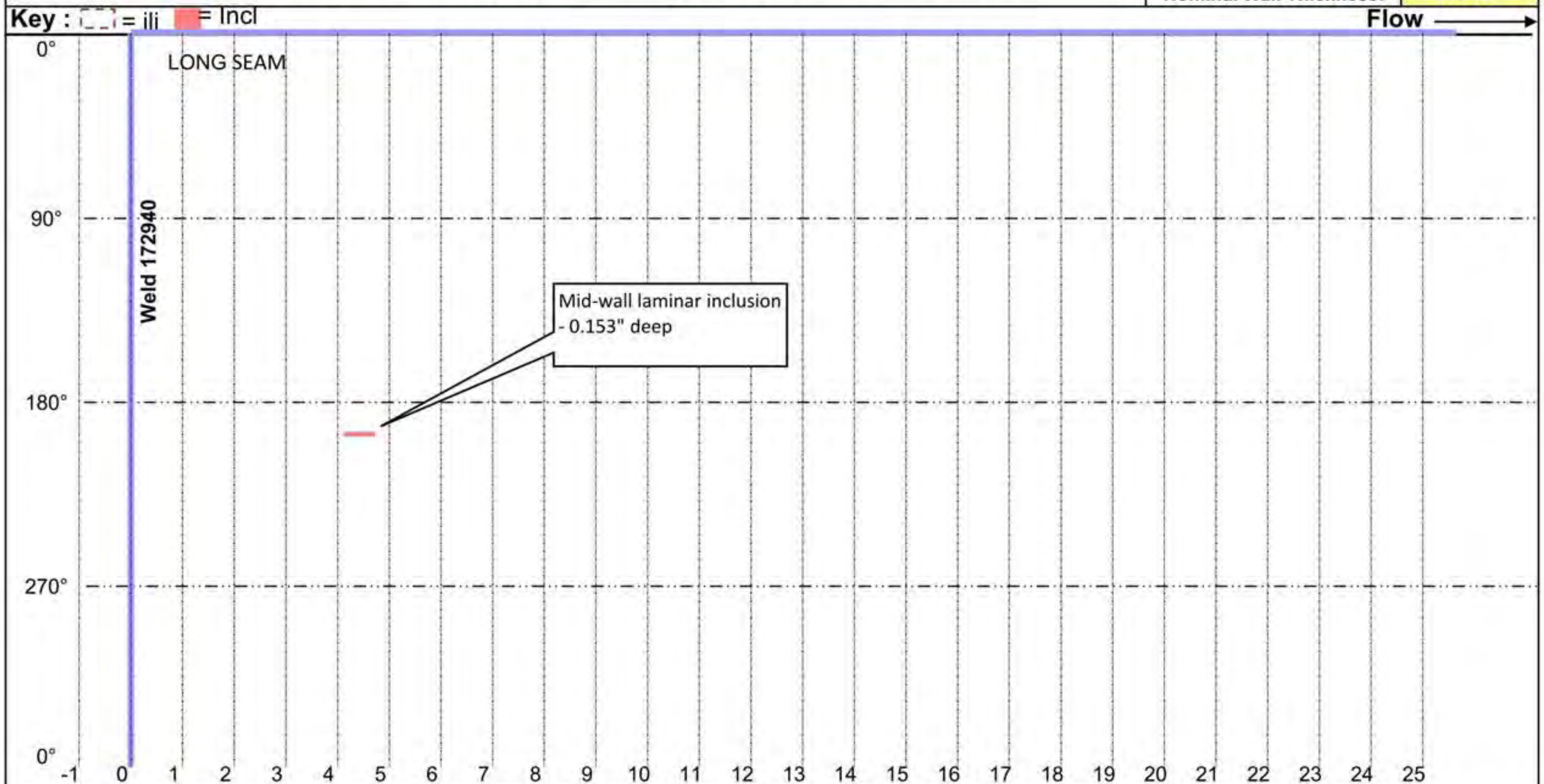
Date of Exam	Technician	Certification(s)
5/1/13	**Jeff Hecht**	**Lvl III**

SGS
PiiNDE
PIPELINE INTEGRITY SPECIALISTS

ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference:	16310+25.62		ODO to U/S GW:	81602.14
	Distance to US Reference:	4501			
	ODO to Primary Anomaly		Dig #	Upstream GW #	
	81627.98		12	17290	

Graphical Representation of Pipe Body Anomalies - Plan View

Pipe:	20.000" X42
Nominal Wall Thickness:	0.312"



Measurement is Per Joint

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

SGS PfiNDE PIPELINE INTEGRITY SPECIALISTS	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report	US Reference:	16310+25.62	ODO to U/S GW:	81602.14
		Distance to US Reference:	4501.09		
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:	
	GE (PII/TFI) / Run Date: July 2012	81627.98	12	17290	

Description of photograph

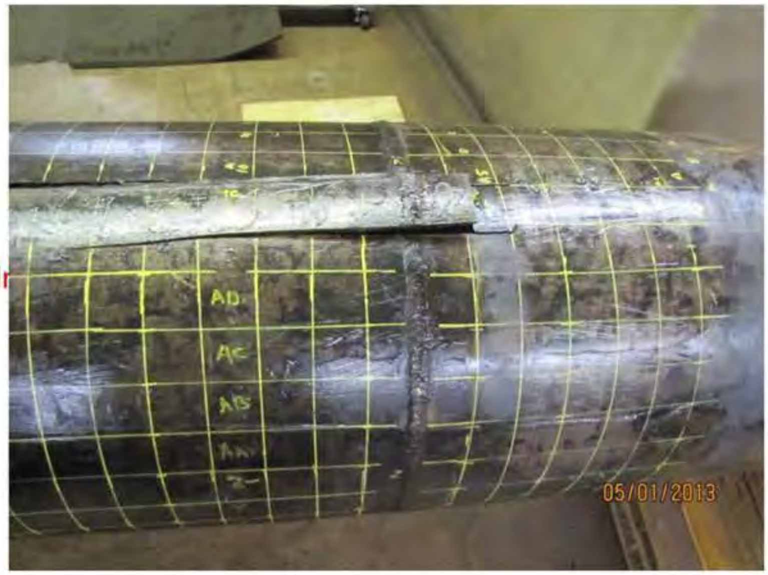
General site photo - Pipe looking Upstream

Description of photograph

Scan Area for Grid 141 Scan (Downstream 12")

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

SGS / PfiNDE Pipeline Integrity Specialists	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference:	16310+25.62	ODO to U/S GW:	81602.14
		Distance to US Reference:	4501.09		
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:	
		81627.98	12	17290	



Description of photograph

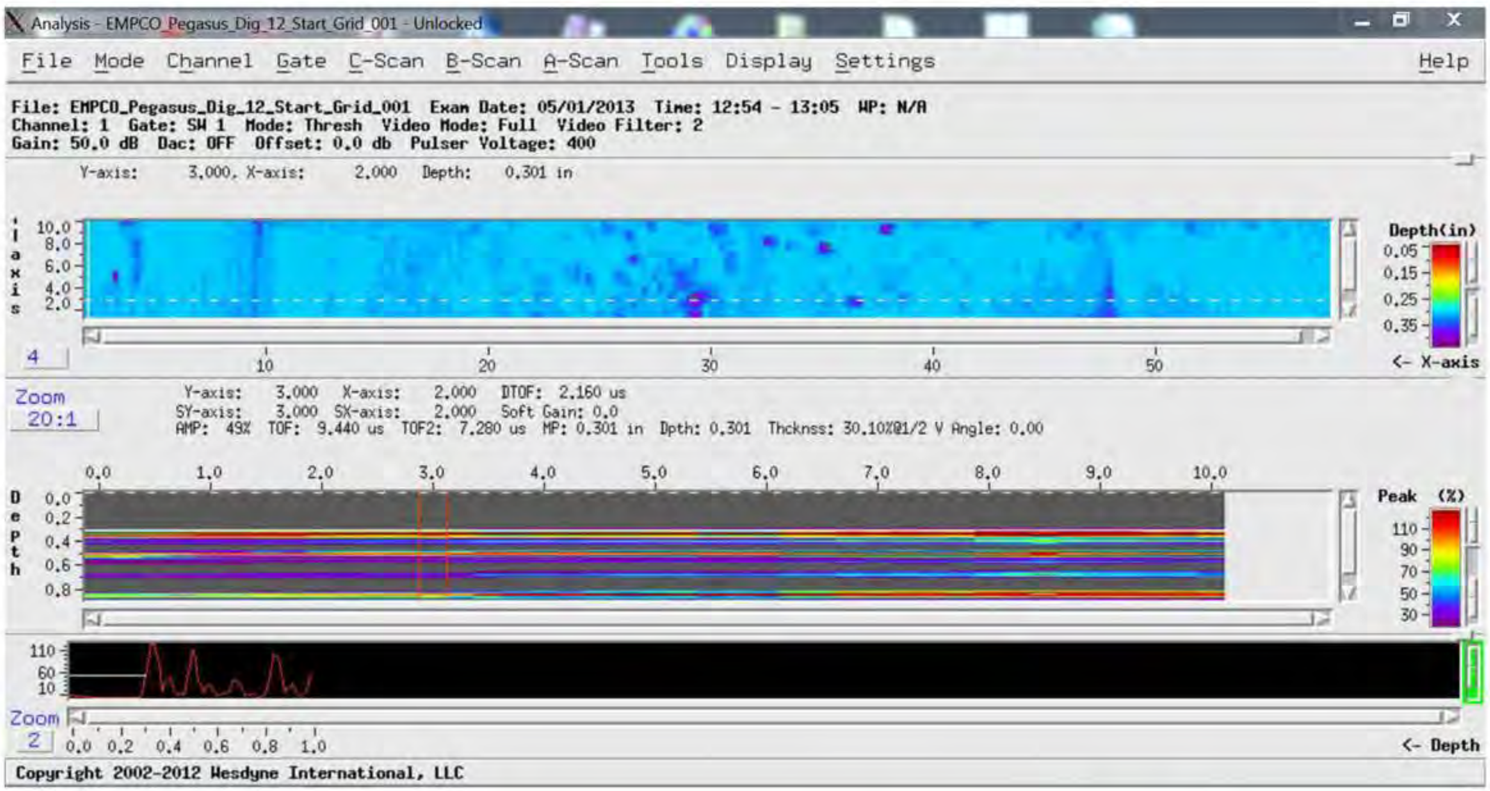
Scan Area for Grid 1 Area (12" upstream of GW)

Description of photograph

Anomaly 1 Area Marked on Pipe for Sectioning

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

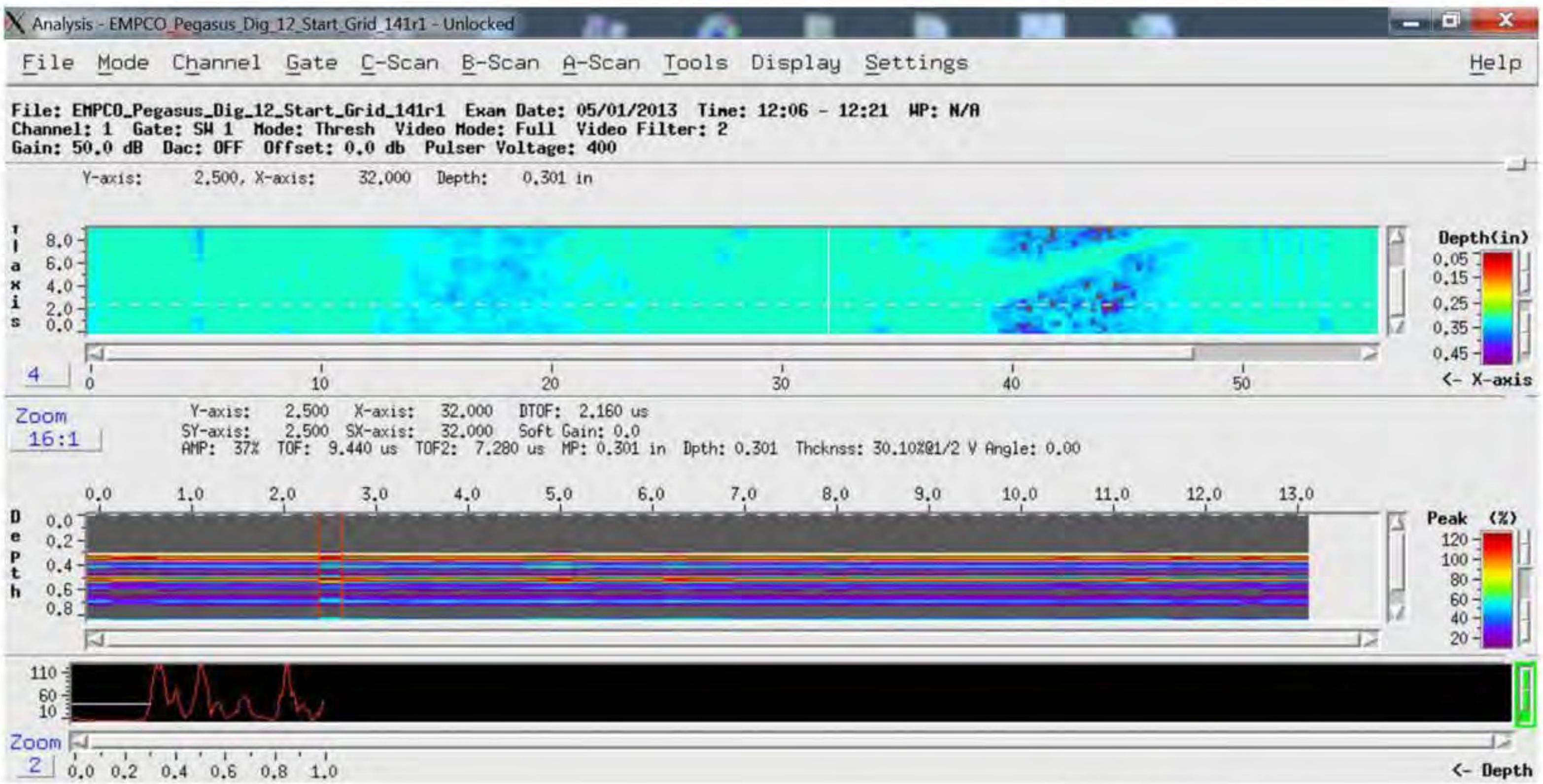
SGS PfiNDE Pipeline Integrity Specialists	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference:	16310+25.62	ODO to U/S GW:	81602.14
		Distance to US Reference:	4501.09		
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:	
		81627.98	12	17290	



Grid 1 Area Scan

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

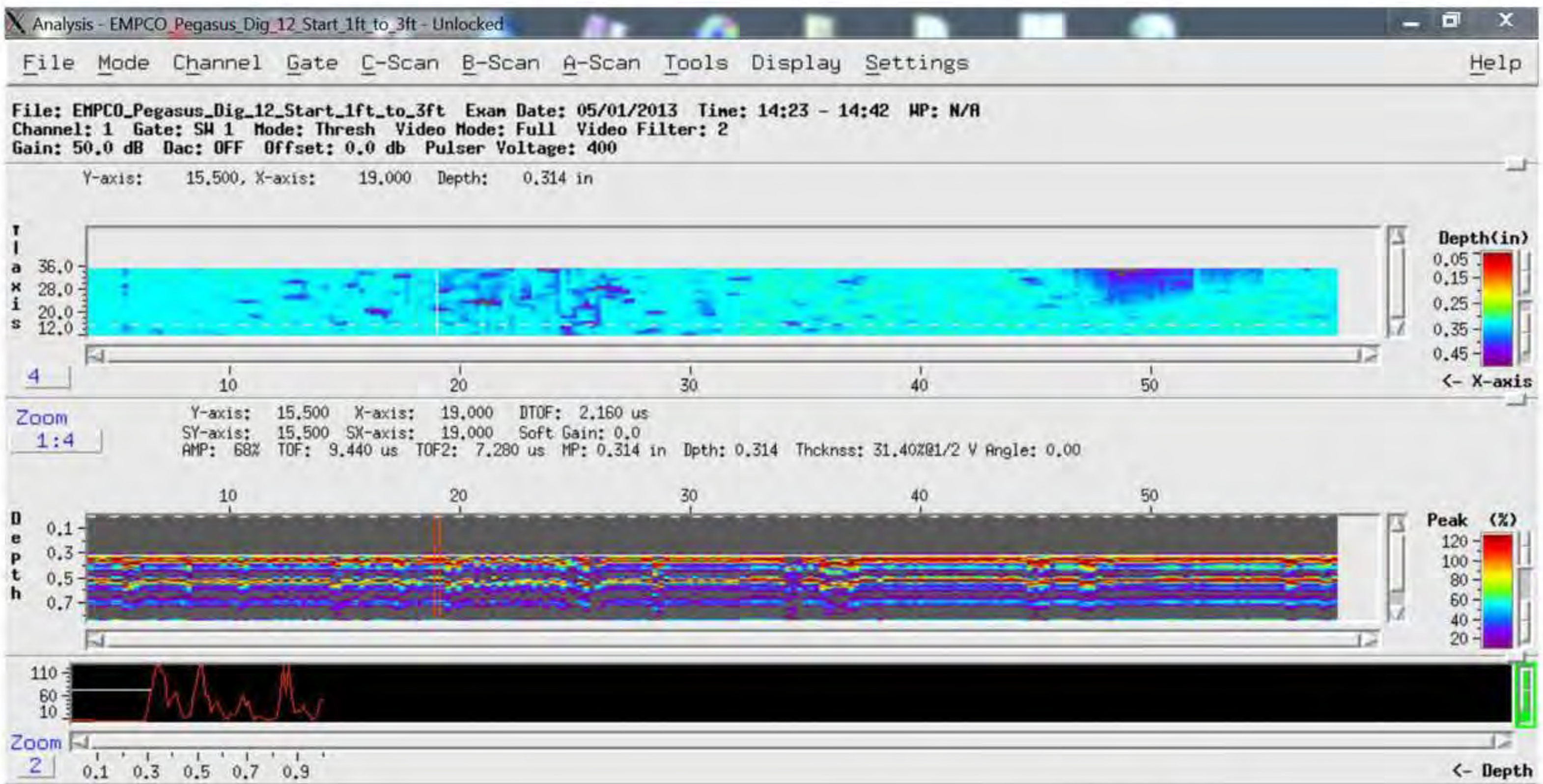
SGS PfiNDE PIPELINE INTEGRITY SPECIALISTS	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference:	16310+25.62	ODO to U/S GW:	81602.14
		Distance to US Reference:	4501.09		
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:	
		81627.98	12	17290	



Grid 141 Area Scan

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

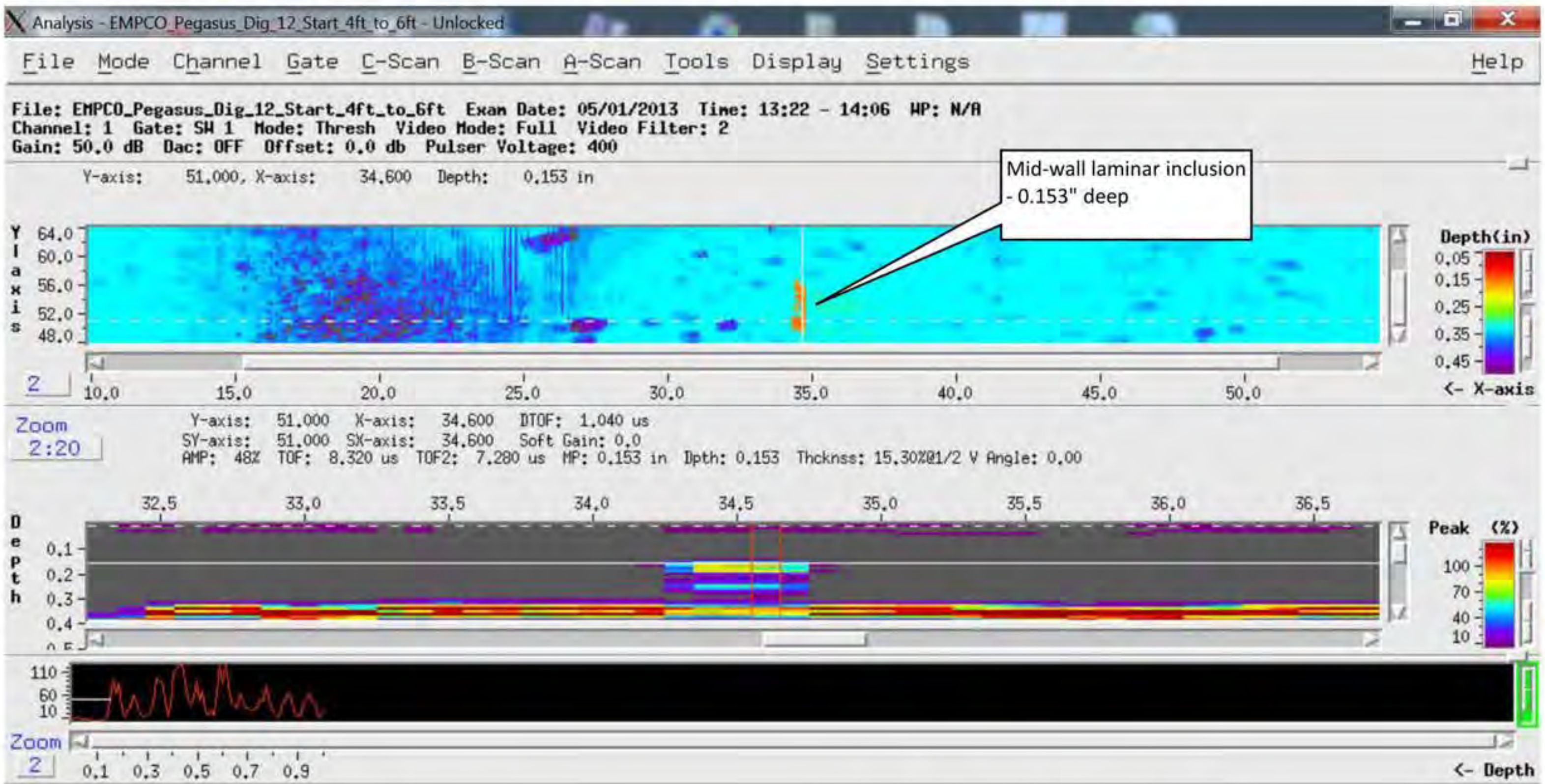
SGS PfiNDE PIPELINE INTEGRITY SPECIALISTS	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference: 16310+25.62 Distance to US Reference: 4501.09		ODO to U/S GW: 81602.14
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:
		81627.98	12	17290



Scan from 1 ft to 3 ft

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

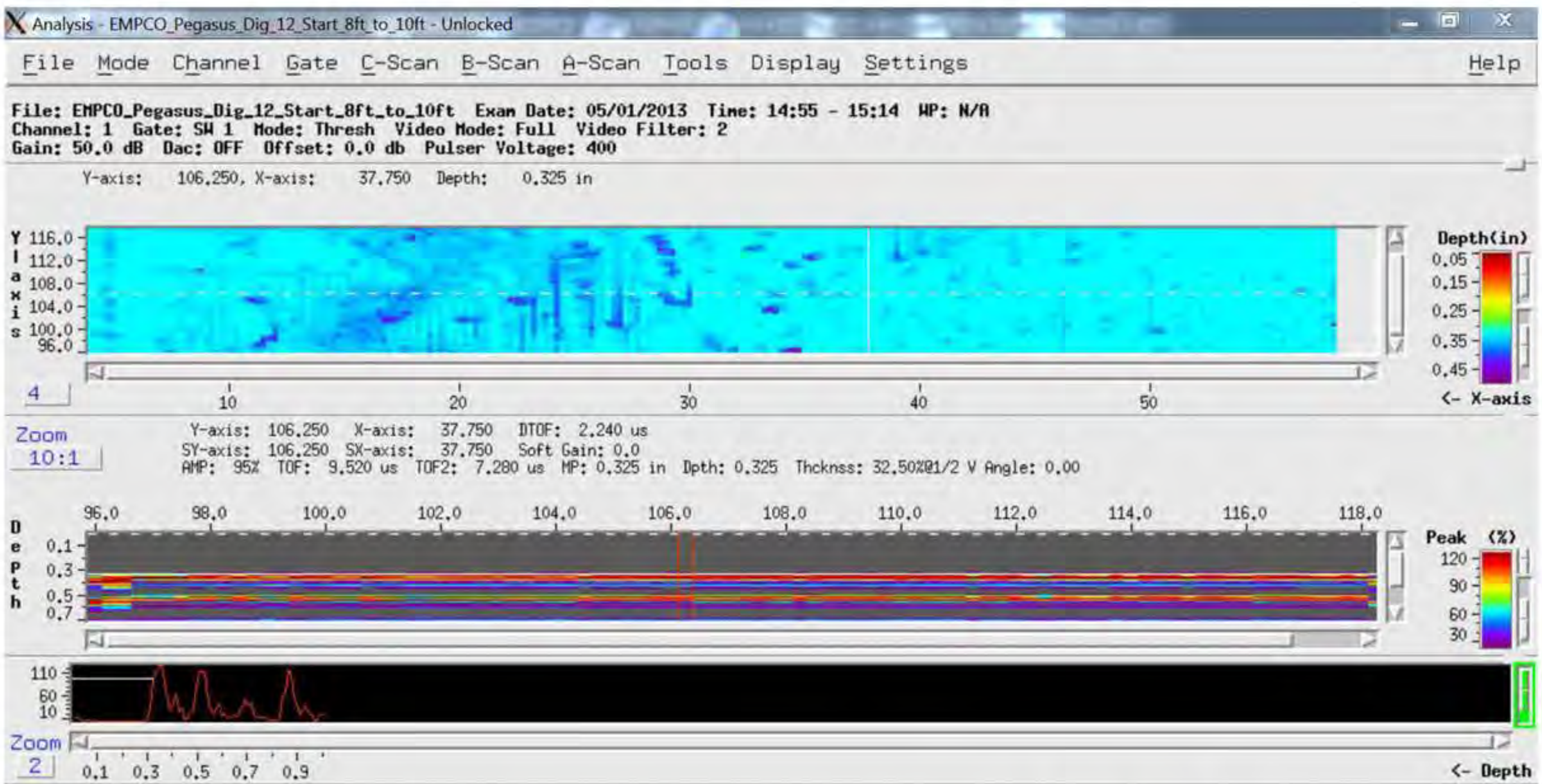
SGS PfiNDE Pipeline Integrity Specialists	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference:	16310+25.62	ODO to U/S GW:	81602.14
		Distance to US Reference:	4501.09		
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:	
		81627.98	12	17290	



Scan from 4 ft to 6ft (Anomaly Area)

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

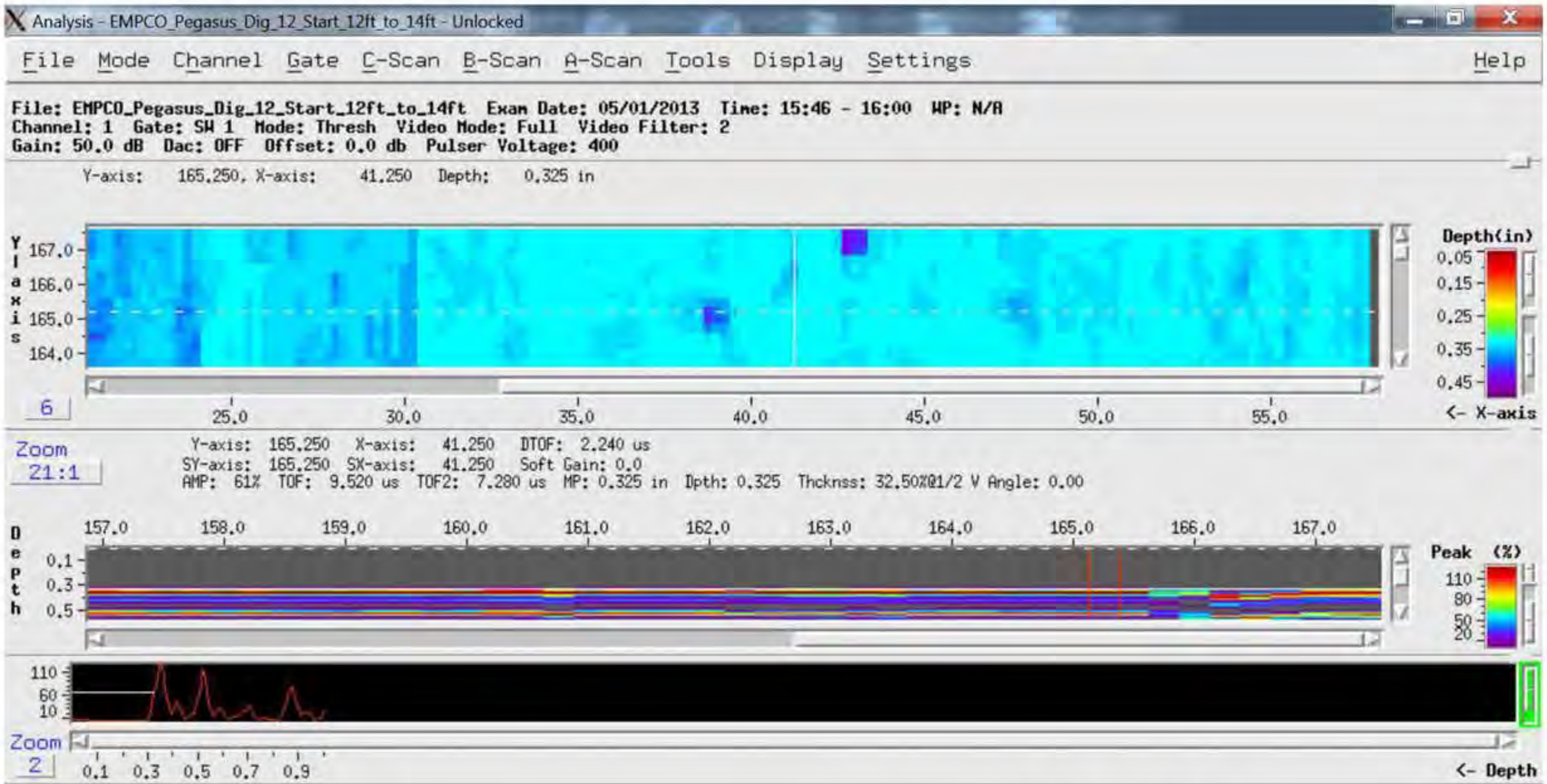
SGS PfiNDE Pipeline Integrity Specialists	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference:	16310+25.62	ODO to U/S GW:	81602.14
		Distance to US Reference:	4501.09		
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:	
		81627.98	12	17290	



Scan from 8ft to 10ft

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

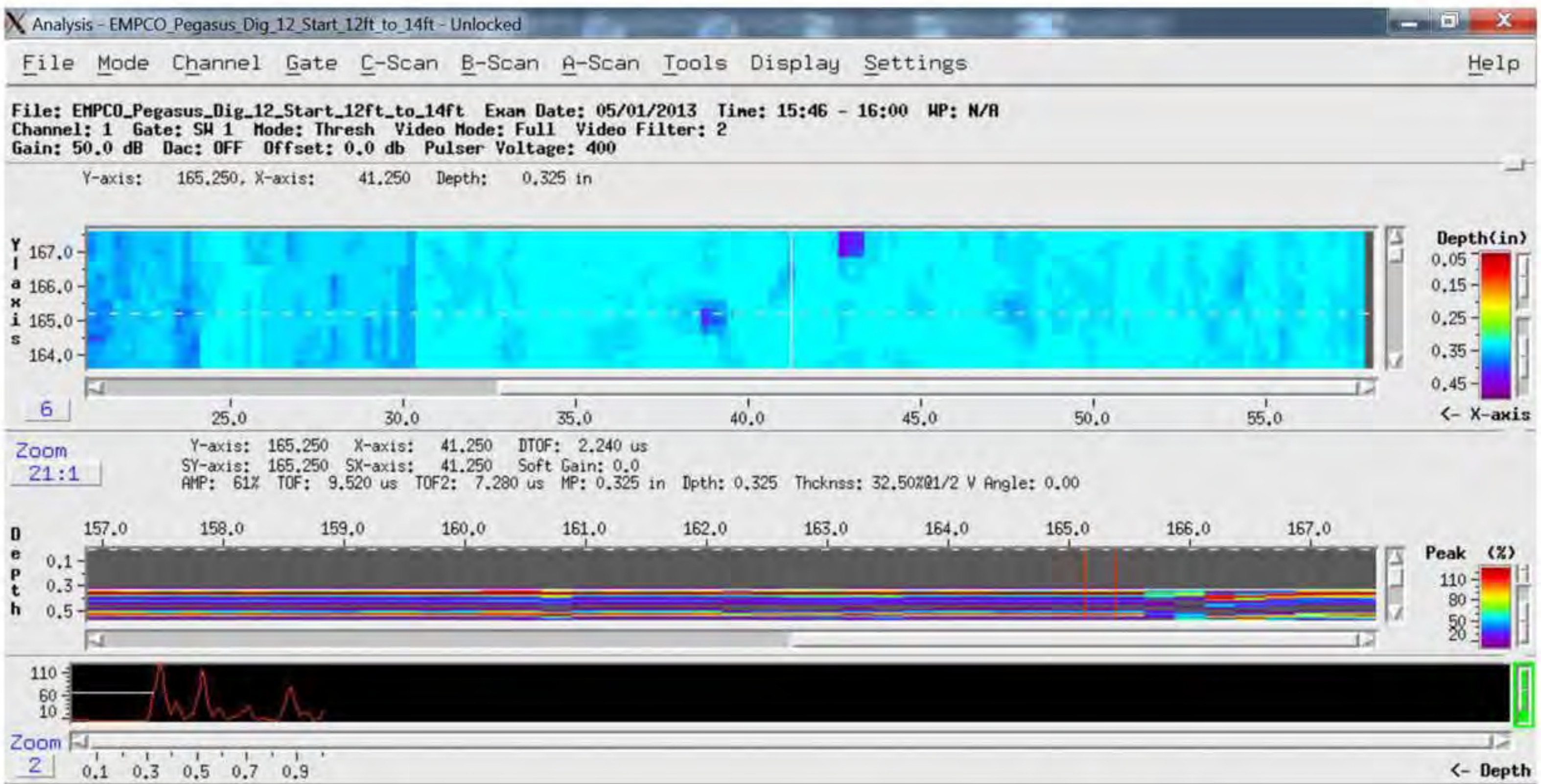
SGS / PfiNDE Pipeline Integrity Specialists	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference:	16310+25.62	ODO to U/S GW:	81602.14
		Distance to US Reference:	4501.09		
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:	
		81627.98	12	17290	



Scan from 12ft to 14ft

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

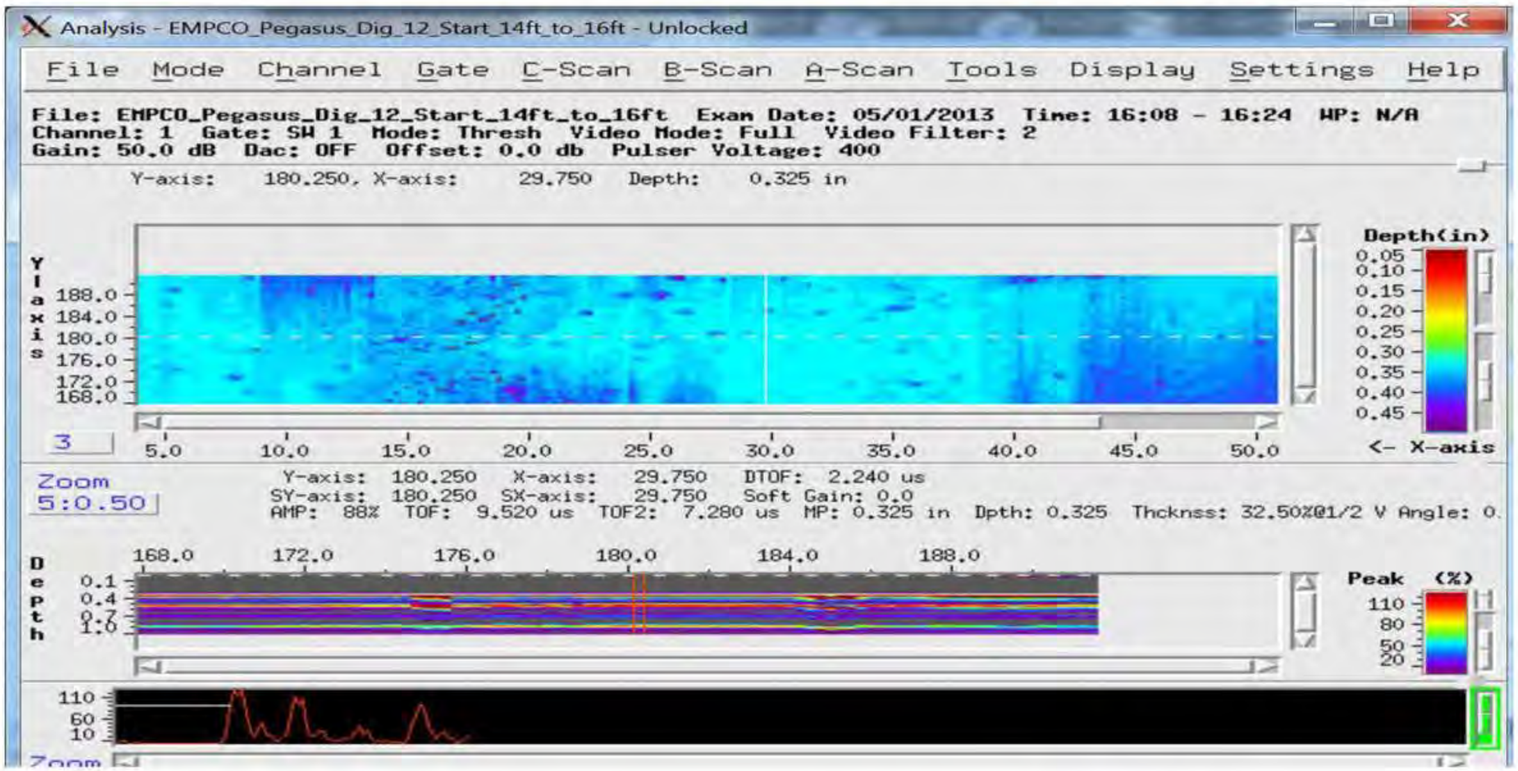
SGS PfiNDE PIPELINE INTEGRITY SPECIALISTS	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference:	16310+25.62	ODO to U/S GW:	81602.14
		Distance to US Reference:	4501.09		
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:	
		81627.98	12	17290	



Scan from 12ft to 14ft

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

SGS PfiNDE Pipeline Integrity Specialists	ExxonMobil Pipeline Inline Inspection Tool Correlation NDE Report GE (PII/TFI) / Run Date: July 2012	US Reference: 16310+25.62 Distance to US Reference: 4501.09		ODO to U/S GW: 81602.14
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:
		81627.98	12	17290



Scan from 14ft to 16ft

Date of Exam	Technician	Certification(s)	
5/1/2013	Jeff Hecht	Lvl III	

SGS PIINDE PIPELINE INTEGRITY SPECIALISTS

ExxonMobil Pipeline

Inline Inspection Tool Correlation NDE Report

GE (PII/TFI) / Run Date: July 2012

US Reference:	**16310 + 25.62ft**	ODO to U/S GW:	**81602.14**
Distance to US Reference:	4501.09		
ODO to Primary Anomaly: 81627.98	Dig # 12	Upstream Girth Weld #:	**17290**

Project: **HURST LAB EVALUATION**　　Pipe Description / Nominals: (**20.000"** **0.312"** **X42**)　　Segment: **Conway to Corsicana**

	U/S Joint	Anomaly Joint	D/S Joint
Joint Length:	NV	NV	NV
LS Circ Position:	NV	12:00	NV

Inspection Area Dimensions

Length of Pipe Examined: 24.67'
Axial Start: -1.00'　End: 23.67'
Circ Start: 0°　End: 360°

Conditions:
Soil pH: NA
Top of Ditch P-S: NA
Btm of Ditch P-S: NA
Soil Resistivity: NA ohm/cm

Seam Type: SAW ☐ FW ☐ ERW ☒ DSAW ☐ SMLS ☐ Lap ☐

Coating Type: Tape ☐ FBE ☐ Coal Tar ☒

Actual Profile Data: T1 316 T2 312 TW 383 WW 520 WH 0

NDE Methods

Visual ☒　WCAMT ☒　UT-FAST ☒　UT-0 Degree ☒　UT-Shear ☒　UT- Phased Array ☒

Anomaly Information

	Log Start (ft)	Log length (in)	Log circ start (clk)	Log circ extent (in)	Log Depth (%)	Start of Ind (ft)	End of Ind (ft)	Axial Length of Ind (in)	Circ start (clk)	Circ end (clk)	Circ extent (in)	Pipe Thk at Ind (mils)	Max Ind Depth (mils)	Depth, Max %	Pipe or weld	ID, OD or Mid	Flaw Type	Grind Length (in)	NDE Method	NDE Comments or Remarks
1																				See Remarks Below
2																				
3							N													
4									A											
5																				

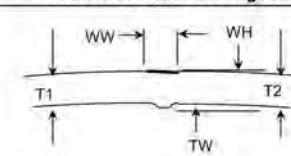
NG=Not Given　NV= Not Verified　NA= Not Applicable　VI= Verified by Dig Inspector

NDE Remarks:

A "map" of ultrasonic thickness measurements were taken from 12 inches upstream of the girth weld to 12 inches downstream of the rupture for 360 degrees around the pipe surface.
The thickness measurements were taken around the entire circumference along the length of pipe at 2 inch grid intervals.
No internal corrosion areas were indentified during the ultrasonic examination. The pipe thickness readings varied from 0.288" to 0.316" along the pipe.

The grid rows identified as "A" and "AE" on the thickness map represent the 2" areas immediately adjacent to the rupture face. Column "7" represents the upstream girth weld cap. (A1 to AE147)

Thickness Profile of Long Seam



Repair type	Sleeve area	Start	End

A = Type "A" sleeve; B = Type "B" Sleeve; C = Clockspring; N = No repair required

Date of Exam	Technician	Certification(s)
4/28/2013 to 5/1/2013	**Jeff Hecht**	**Level III**

SGS PfiNDE Pipeline Integrity Specialists	ExxonMobil Pipeline	US Reference:	16310 + 25.62ft	ODO to U/S GW:	81602.14
	Inline Inspection Tool Correlation NDE Report	Distance to US Reference:	4501.09		
		ODO to Primary Anomaly	Dig #	Upstream Girth Weld #:	
	GE (PII/TFI) / Run Date: July 2012	81627.98	12	17290	

Description of photograph

Grided Pipe looking upstream

(pipe gridded 12" downstream of rupture).

Description of photograph

Downstream Girthweld End of pipe
(pipe gridded 12" upstream of girthweld)

Date of Exam	Technician	Certification(s)	
4/28/2013 to 5/1/2013	Jeff Hecht	Level III	

Conway_Corsicana Odo 81627.98 Dig 12
Conway to Corsicana
HURST LAB

2" GRID

	1	2	3	4	5	6	7	8	9	10	11	12
A	302	299	301	313	312	310	US GIRTH WELD	314	315	312	313	313
B	313	301	300	310	309	313		303	310	313	310	301
C	312	311	310	311	316	320		313	313	313	313	316
D	301	310	310	309	308	303		309	311	300	303	311
E	310	311	311	308	310	310		310	308	309	310	310
F	314	314	314	315	310	310		311	309	311	310	311
G	307	306	305	305	308	308		308	308	312	309	310
H	312	314	308	307	306	310		308	312	311	310	312
I	318	312	312	313	313	313		316	316	313	316	304
J	303	311	308	310	311	312		314	312	312	313	314
K	310	305	305	306	305	308		312	313	310	309	309
L	305	310	308	310	310	307		312	311	312	311	312
M	310	306	307	310	309	308		312	310	312	311	310
N	310	310	306	305	310	308		310	311	313	311	311
O	306	310	308	308	309	309		310	311	312	312	312
P	308	307	309	307	309	310		310	311	312	311	311
Q	306	309	310	308	310	309		310	311	312	311	310
R	308	307	309	308	310	310		311	310	312	312	310
S	306	309	308	308	310	311		310	310	310	310	312
T	302	309	308	310	310	310		310	310	312	309	309
U	310	308	309	310	310	312		310	310	312	310	310
V	312	310	310	308	308	311		308	308	308	309	310
W	308	310	310	309	310	309		310	310	309	311	309
X	310	309	309	309	310	312		310	312	311	310	310
Y	310	309	309	309	309	309		310	307	307	309	309
Z	308	303	306	306	306	309		310	306	307	302	308
AA	308	307	306	306	306	306		309	310	307	307	308
AB	304	304	304	312	303	311		310	310	303	302	312
AC	305	307	307	303	303	307		310	311	303	303	303
AD	309	304	306	307	308	308		310	310	308	309	309
AE	305	307	307	303	303	307		310	311	303	303	303

Conway_Corsicana Odo 81627.98 Dig 12
Conway to Corsicana
HURST LAB

2" GRID

13	14	15	16	17	18	19	20	21	22	23	24	25
314	316	316	316	315	318	318	305	318	317	318	313	316
312	317	314	320	320	311	307	315	317	315	316	313	306
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305	312	310	310	305	305	305	305	310	305	306	311	312

Conway_Corsicana Odo 81627.98 Dig 12
Conway to Corsicana
HURST LAB

2" GRID

26	27	28	29	30	31	32	33	34	35	36	37	38
316	316	313	312	304	306	312	304	312	312	314	314	314
314	318	317	302	303	312	312	314	312	312	311	311	312
314	313	316	304	310	312	311	311	311	312	312	312	313
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Conway_Corsicana Odo 81627.98 Dig 12
Conway to Corsicana
HURST LAB

2" GRID

39	40	41	42	43	44	45	46	47	48	49	50	51
315	312	314	314	314	314	314	308	308	308	312	314	314
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Conway_Corsicana Odo 81627.98 Dig 12 **2" GRID**
Conway to Corsicana
HURST LAB

52	53	54	55	56	57	58	59	60	61	62	63	64
314	314	308	307	306	308	312	305	312	308	312	309	307
312	312	305	305	305	305	305	307	304	308	309	304	308
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Conway_Corsicana Odo 81627.98 Dig 12
Conway to Corsicana
HURST LAB

2" GRID

65	66	67	68	69	70	71	72	73	74	75	76	77
307	309	310	309	310	309	309	309	309	310	310	310	310
307	310	308	309	309	309	306	309	306	308	310	309	310
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307	308	308	306	305	306	307	305	305	307	308	306	305
306	305	304	306	305	305	305	304	308	307	306	305	306

Conway_Corsicana Odo 81627.98 Dig 12 **2" GRID**

Conway to Corsicana

HURST LAB

78	79	80	81	82	83	84	85	86	87	88	89	90
308	311	312	311	312	312	313	310	312	310	310	311	310
306	309	305	307	306	306	306	310	310	310	310	310	311
307	305	305	305	311	306	307	310	311	309	309	309	306
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Conway_Corsicana Odo 81627.98 Dig 12 **2" GRID**

Conway to Corsicana

HURST LAB

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Conway_Corsicana Odo 81627.98 Dig 12
Conway to Corsicana
HURST LAB

2" GRID

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Conway_Corsicana Odo 81627.98 Dig 12
Conway to Corsicana
HURST LAB

2" GRID

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Conway_Corsicana Odo 81627.98 Dig 12
Conway to Corsicana
HURST LAB

2" GRID

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Conway_Corsicana Odo 81627.98 Dig 12
Conway to Corsicana
HURST LAB

2" GRID

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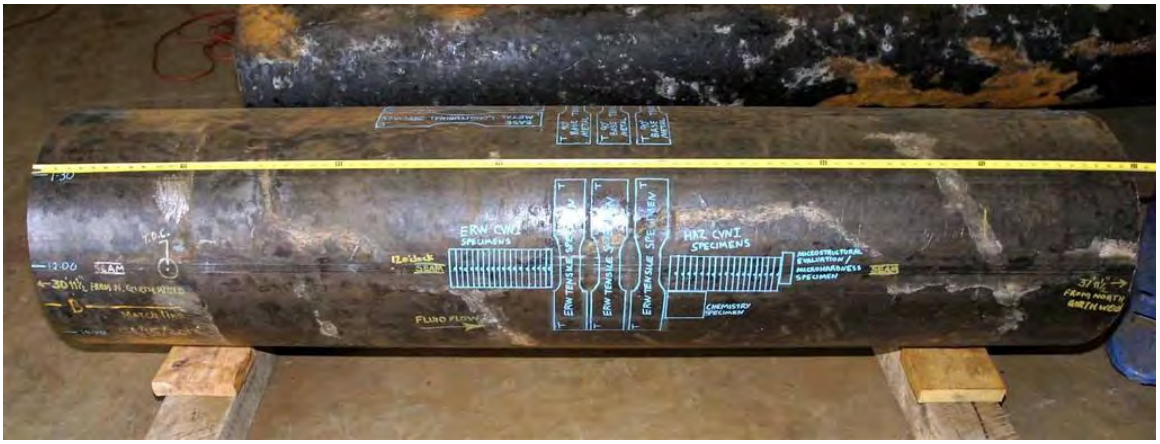
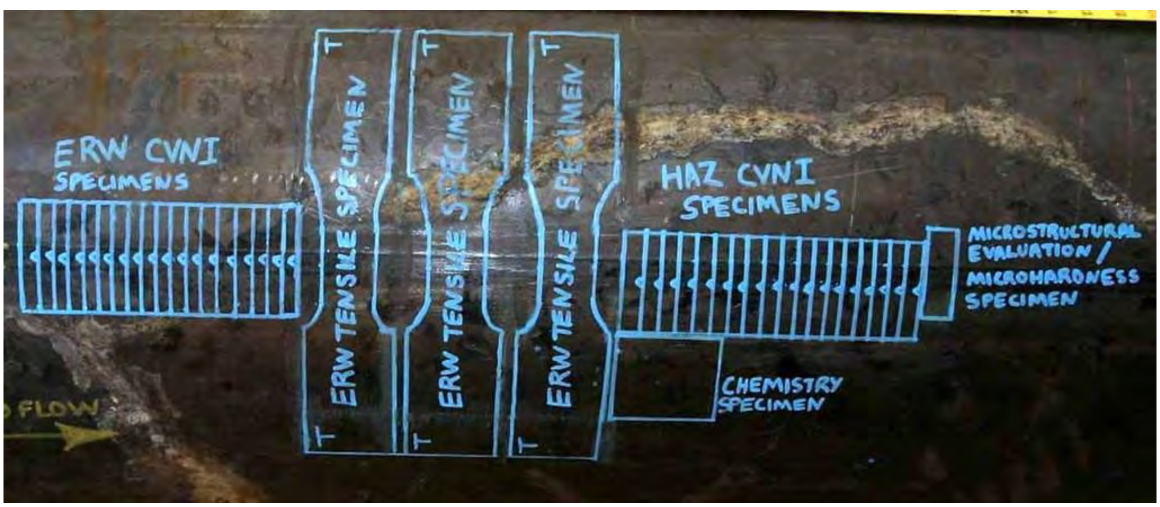
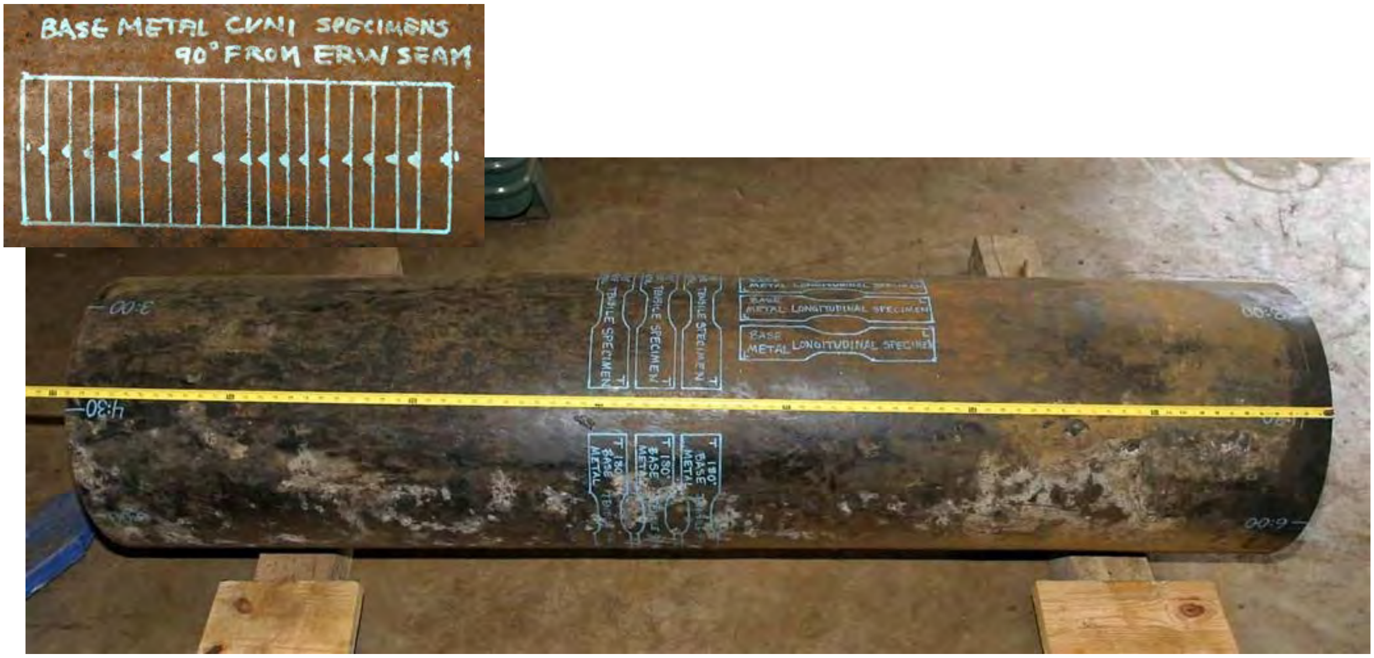
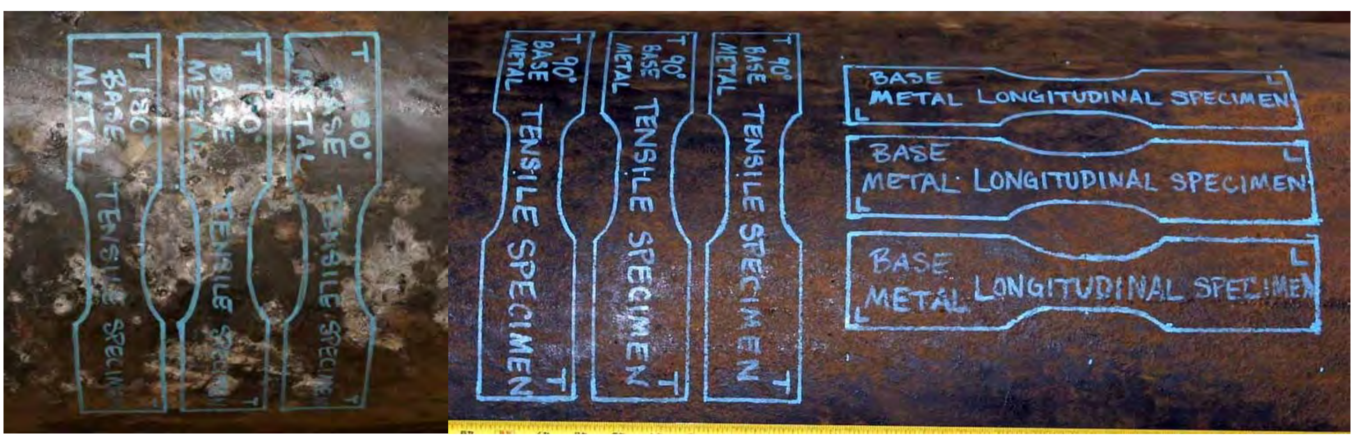
Appendix V





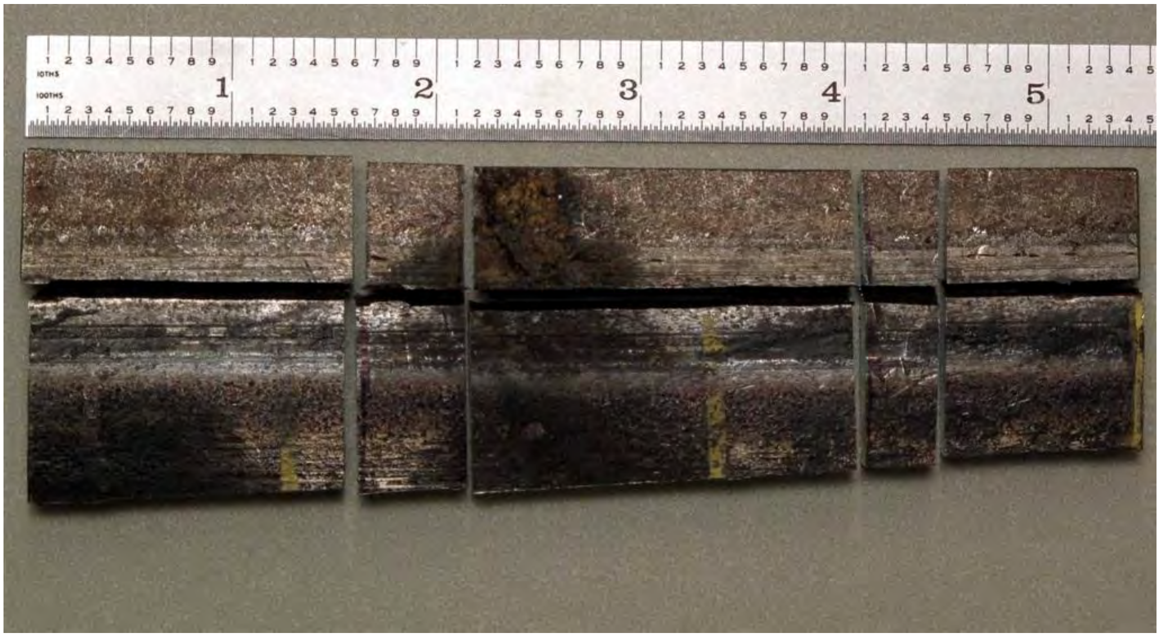
The photographs display an overall view of the area along the ERW seam on the intact 19' 10" long section of the pipe, and a closer view of the area where the ERW seam test specimens were removed from.

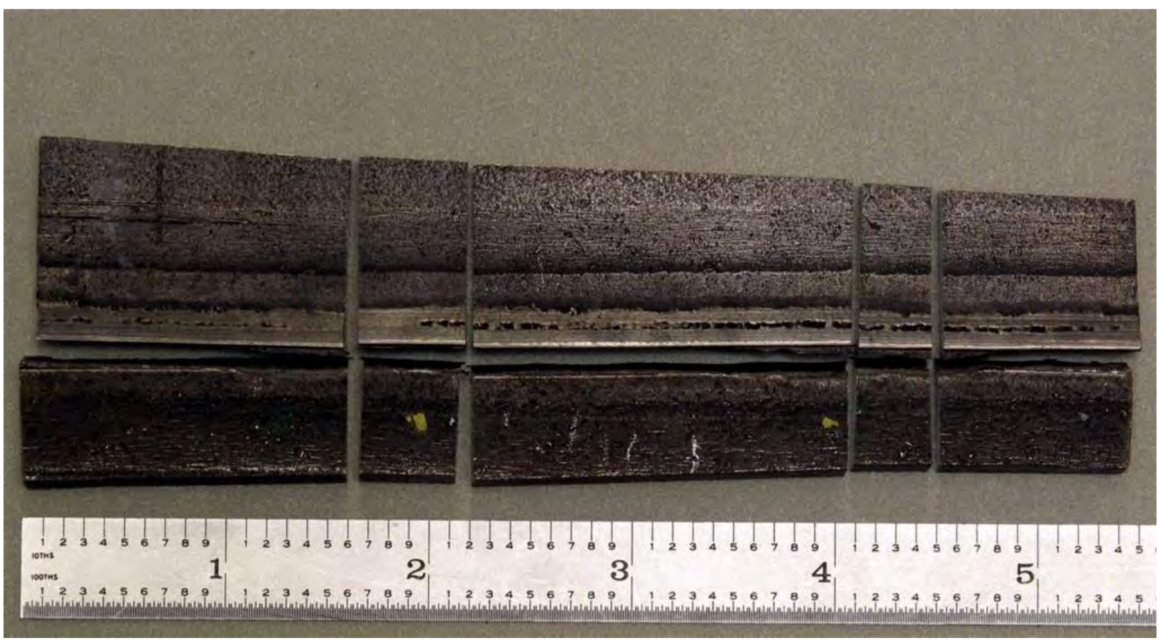




The photographs display an overall view of the area opposite the ERW seam on the intact 19' 10" long section of the pipe, showing where the longitudinal and transverse base metal test specimens were removed from. The insert photograph shows the location of the base metal CVN impact test specimens.

The photograph displays the test specimens that were removed from the intact 19' 10" long section of pipe, after machining and prior to testing. The various test specimens were machined and tested in accordance with ASTM A370-12a and the applicable sections of each edition of API 5L.





The photographs display the O.D. and I.D. surface, respectively, at the locations where the cross-sections were removed through the fractured area of the ERW seam and metallographically prepared for microstructural evaluation.

APPENDIX E

APPENDIX E

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Tab F - EMPCo 2005-2006 Pegasus Pipeline Hydrotesting

Tab G - EMPCo Pegasus Pipeline Operational and IM History – Corsicana to Patoka

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Executive Summary

The cause of the rupture at MP 314.77 was the failure of the low-frequency (LF) electric resistance weld (ERW) pipe seam as a result of the presence of original manufacturing defects that grew and extended to the point of failure during the operational period of the pipe.

Contributing factors were identified in PHMSA's investigation of the accident; namely 1) EMPCo's Integrity Management (IM) process failure to identify the threat and properly characterize the risks on the Pegasus Pipeline, 2) EMPCo's Seam Failure Susceptibility Analyses (SFSA) failure to consider portions of the Pegasus Pipeline as susceptible to seam failure, 3) EMPCo's failure to continuously improve and incorporate lessons learned into its IM processes, and 4) EMPCo's failure to re-assess the pipeline within the required regulatory timeframe with a method suitable for the metallurgy of the pipe, and the manufacturing flaws known to be present in the pipeline.

EMPCo had in place detailed processes for threat identification and integrity assessments. However, these processes and their implementation failed to identify an "Identified Threat" that would have triggered risk reduction actions by EMPCo. The EMPCo Threat Identification and Risk Analysis (TIARA) process failed to characterize the risk as being "Likely" to occur and have "Tangible" consequences [See Tab C]. Additionally, EMPCo did not incorporate industry knowledge [See Tab A] or internal knowledge that should have been gained from failure investigations [See Tabs F and J] into its IM procedures for management of pre-70 ERW pipelines.

EMPCo's integrity management decision making did not demonstrate that pipeline safety was the overriding priority. There were indications that risk-significant decisions were made without adequate management review or technical input. EMPCo did not use conservative assumptions in its seam failure susceptibility and fatigue analyses. Decisions documented resource constraints, both time and money, as justifications for the data collected and used, analyses performed, and the timing of inspections that were to be performed. The processes used in the integrity management practices did not demonstrate continuous learning or enhancements intended to improve safety, instead it appeared that decisions were often based upon time constraints or cost reduction without adequate consideration of the impacts of changes, and were not up-to-date with current knowledge. The thresholds to take risk reduction actions were unreasonably high, and risk decisions were based primarily upon the relative risk of the assets in comparison to other EMPCo assets instead of threat specific preventive and mitigative actions.

The pipeline segment between Conway Pump Station and Foreman Pump Station was not identified as susceptible to seam failure, and a Seam Integrity Assessment Plan (SIAP) was not developed to manage the threat of the manufacturing related defects that were known to be present in the Pegasus Pipeline [See Tab D], and particularly in the Conway to Foreman segment of the pipeline where the failure occurred.

As a result of EMPCo's failure to identify the Pegasus Pipeline System, and in particular the Conway to Foreman segment as susceptible to seam failure, EMPCo erroneously relied upon the use of pressure-cycle-fatigue modeling software to determine "*if and when a TFI tool*" should be run, and to determine the integrity re-assessment interval, all the while maintaining that there had been no pressure-cycle-fatigue related failures on the pipeline.

EMPCo's IMP procedures failed to consider failure mechanisms other than selective seam corrosion and "*fatigue due to normal operations*" as causes of degradation of the ERW long seams over time in its seam failure susceptibility determination flow charts, even though there were indications of seam degradation in the 2006 hydrotest failure metallurgical test reports, and well known threats were associated with the specific vintage and manufacture of the LF-ERW pipe used in the Pegasus Pipeline [See Tabs A, D, E and H].

EMPCo failed to perform an integrity assessment with a method capable of addressing the specific defects known to be present in the pipeline segment within the required regulatory timeframe of five years, not to exceed 68 months which should have occurred in 2011. The characteristics of the pipe, specifically the low toughness of and adjacent to the ERW bondline would have indicated that the most effective integrity assessment method for the pipeline segment was a hydrotest [See Tab E and H], until such time that confidence could be gained in the ability of in-line inspection tools to reliably identify and quantify the type of flaws in and adjacent to the ERW seam of the Pegasus Pipeline.

ExxonMobil's Chairman and CEO testified to the United States Congress and the *National Commission on BP Deepwater Oil Spill and Offshore Drilling* about the importance of OIMS and the adherence to industry best practices as significant factors in accident prevention [See Tab B]. Similarly, PHMSA believes that if industry best practices are followed, specifically with regard to the management of pre-70 LF ERW pipe, accidents like the Pegasus Pipeline Mayflower Spill should not happen.

--end--

Summary Discussion of Contributing Factors

Exxon Mobil Pipe Line Company (EMPCo) relied upon Exxon Mobil Corporation's (ExxonMobil) global management processes, its proprietary threat identification and risk assessment model, and EMPCo integrity management processes to apply risk based practices to manage the integrity of the Pegasus Pipeline which is owned by Mobil Pipe Line Company, an affiliate of ExxonMobil. The Pegasus Pipeline segment from Patoka to Corsicana is about 648 miles long with roughly 634 miles, or 97.8% of the mileage in or potentially affecting High Consequence Areas as defined in 49 CFR 195.450, and subject to the requirements of 49 CFR 195.452, *Pipeline integrity management in high consequence areas* (HCAs).

ExxonMobil operates its global assets under the Operations Integrity Management System (OIMS). OIMS [for a detailed description of OIMS and additional technical references see Tab B] is a safety management system that ExxonMobil describes as a process having "*11 elements, each with clearly defined expectations that every operation must fulfill. Management systems put into place to meet OIMS expectations must show documented evidence of the following five characteristics:*

- *The scope must be clear and the objectives must fully define the purpose and expected results;*
- *Well-qualified people are accountable to execute the system;*
- *Documented procedures are in place to ensure the system functions properly;*
- *Results are measured and verified that the intent of the system is fulfilled; and*
- *Performance feedback from verification and measurement drives continuous improvement of the system.*

Management of the integrity of the Mobil Pegasus Pipeline is carried out by EMPCo under the umbrella of OIMS and the numerous supporting processes and procedures that make up the operating and maintenance instructions for EMPCo pipeline assets. The management of the failure prevention related to any potential ERW long seam integrity threats is covered by the processes found in the EMPCo IMP User's Manual and its associated processes (EMPCo IMP). All but one of the five characteristics listed above appear to have had shortcomings in the EMPCo IMP management processes.

The federal pipeline safety regulations in 49 CFR 195.452 require an operator of hazardous liquid pipelines *to assess, evaluate, repair and validate through comprehensive analysis the integrity of hazardous liquid pipeline segments that, in the event of a leak or failure, could affect populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways. OPS [requires] that an operator develop and follow an integrity management program that provides for continually assessing the integrity of all pipeline segments that could affect these high consequence areas, through internal inspection, pressure testing, or other equally effective assessment means. The program must also provide for periodically evaluating the pipeline segments through comprehensive information analysis, remediating potential problems found through the assessment and evaluation, and ensuring additional protection to the segments and the high consequence areas through preventive and mitigative measures.*

Through this required program, hazardous liquid operators ***will comprehensively evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the pipeline segment***

and consequences of a failure on a high consequence area. *This includes analyzing information on the potential for damage due to excavation; data gathered through the required integrity assessment; results of other inspections, tests, surveillance and patrols required by the pipeline safety regulations, including corrosion* control *monitoring and cathodic protection surveys; and information about how a failure could affect the high consequence area.*

EMPCo failed to implement processes to ensure that the intent and specific requirements of the federal pipeline safety regulations were met. Further, EMPCo had in place its own operating procedures (OIMS, EMPCo IMP, etc.) that by federal regulations must also be followed which were not fully implemented.

The five OIMS characteristics listed above were not all met. EMPCo had documented procedures in place, but their adequacy in meeting the requirements in the federal pipeline safety regulations, was not fully demonstrated. The scope was at times unclear, and it appeared that efforts were taken to avoid undesired outcomes that would have required additional activities be undertaken by EMPCo creating what appeared to be conflicting objectives that favored short term fiscal goals over operational conservatism. There appeared to be a lack of understanding of technical aspects of the analysis models that were used, and where experience or knowledge was not readily available within EMPCo, outside technical support was not used to supplement EMPCo corporate knowledge. There were no apparent feedback loops utilized to measure the effectiveness of the IM decisions, and little enhancement or improvement was observed over the ten year period that the current EMPCo pre-70 ERW pipe IM practices have been in place.

The EMPCo IMP includes the use of its proprietary TIARA model. TIARA [for a more detailed description of TIARA and additional technical references see Tab C] is the backbone for risk management decision processes implemented by EMPCO for pipeline assets subject to the federal pipeline safety regulations in 49 CFR 195. The 200+ page TIARA user guide describes the model's shortcomings.

> *While this model works quite well at comparing the risk of a large number of EMPCo pipeline segments, it is less adept at identifying specific integrity threats to each of those segments. Other models, such as ASME B31.8S, offer clearer insights into the specific integrity threats for a given pipe segment.*

EMPCo identified the "main risk for the system [as] external corrosion and potential third party damage" on the Pegasus pipeline, and noted the presence of "tap patches" [tap patches were a common practice of fillet welding a patch over a hole from hydrotest tap connections used during original construction]. EMPCo failed to identify any manufacturing related threats that should have been associated with the pre-70 low frequency electric weld resistance (LF ERW) that was present in roughly 75% of the Pegasus mileage between Patoka and Corsicana. None of these threats were ever raised to a level that required EMPCo to take further Preventive and Mitigative (P&M) actions because they were never considered "Identified Threats" in the EMPCo IM processes, and the thresholds for spill reduction volumes were significantly high enough that "*the amount of spill volume reduction is not to the level of its justification*" for the addition of excess flow reducing valves (EFRDs) or to take other P&M actions.

In all threat identification, risk assessment, and the inter-related IM processes, not once was an "Identified Threat" related to manufacturing defects determined to exist on any of the testable segments of the Pegasus

Pipeline in the IM activities that were carried out between 2005 and 2013 [See Tabs C, D and G]. There was internal discussion observed regarding possible manufacturing defects being an "Identified Threat" on the Conway to Foreman segment in 2011. It "*went away*," [See Tab C] however, when the TFI tool run that was scheduled for the summer of 2011 was input into the TIARA process as having been completed in the March 2011 run of the TIARA model. The inspection by TFI tool was not actually completed until February 6, 2013.

If the goal of risk assessments utilizing TIARA was to evaluate the relative risk of pipeline segments to other EMPCo pipeline assets, TIARA could be considered effective or successful. However, its use for identification of threats requiring mitigation in context of the federal pipeline safety regulations falls short of PHMSA expectations and industry best practices observed by PHMSA in other operator integrity processes. The preamble to the integrity management rulemaking stated [emphasis added], *"To ensure that a high consequence area receives broad protection, **an operator must evaluate all threats to and from the pipeline**, and consider how operating experience in other locations on the pipeline could be relevant to a segment that could affect a high consequence area."*

PHMSA's expectation of threat identification is for an operator to identify potential threats to pipeline assets that are in or could affect HCAs and take appropriate risk reduction actions to minimize the likelihood and consequences of such threats. It was not PHMSA's intent that operators take action only after a threat's risk was deemed to have reached a corporate threshold, as was the case in EMPCo's use of the TIARA model, the EMPCo Risk Matrix [See Tabs B and C], and their role in the EMPCo IM Data Integration and Risk Assessment processes [See Tab C].

EMPCo's OIMS, TIARA and Integrity Management processes were either flawed or not implemented properly, or both. The management processes and their implementation contributed to a preventable failure that was a result of a threat that was well known to the industry [See Tab A] and to the operator through its operational history [See Tabs G and J] yet was not effectively mitigated through the EMPCo IM processes.

Since 2003, much information has been collected and shared on the subject of integrity management of pre-70 ERW seams [See Tab A]. However, no revisions were made in that same time frame to the process EMPCo used to determine whether or not a baseline assessment for seam failure susceptibility was required. Further, no substantive revisions addressing ERW seam integrity were identified in the EMPCo IM Procedures during the PHMSA investigation into this failure.

EMPCo experienced ERW seam failures on assets that are managed under the same EMPCo IM processes at four other locations in Louisiana [See Tab J], yet failed to incorporate lessons learned from those investigations into the IM processes. Instead, EMPCo concluded in the most recent accident investigation the events were unique, and that because the "*Company's Integrity Management Program already, in place, EMPCo does not believe that these findings would likely be applicable to any other locations beyond the Affected Pipeline.*" That conclusion was part of the Root Cause Failure Analysis Report prepared by EMPCo in response to a hook crack manufacturing defect related ERW seam failure that occurred roughly one year prior to this failure. The Affected Pipeline that failed in 2012 was hydrostatically tested in 2001, and in 2007 a TFI tool was used to perform an in-line inspection. Like the Pegasus Pipeline, EMPCo performed a reassessment of the 2012

"Affected Pipeline" outside of the required regulatory inspection interval. Unlike the Pegasus Pipeline, however, EMPCo **did** consider the Louisiana pipeline susceptible to seam failure.

Information contained in the 2005-2006 hydrotest failure metallurgical investigations is valuable [See Tabs F, E and H], and the use of that information is critical in forming the appropriate IM actions for the Pegasus Pipeline. However, there was no indication of incorporation of the information into the IM decision processes, except where EMPCo used lower than recommended CVN values [See Tabs, A, E, and H] in the fatigue analyses and PipeLife modeling. EMPCo attempted to explain the reason for the test failures which occurred at lower than previous test levels as not being the result of time dependent flaws. There is no evidence of evaluation of the test and analysis results by any technical expert or third party other than the laboratory that performed the metallurgical testing. Additionally, there is no evidence that EMPCo sought assistance from the technical experts that developed PipeLife to assist with the assumptions used for the modeling of the pressure-cycle-fatigue analyses in any of the analyses where the reassessment interval was based upon that model. No other type of fatigue models were used, and only a short note that was included on the 2011 seam failure susceptibility analysis flow chart [See Tab D] hinted at EMPCo's awareness of other forms of fatigue that may be occurring.

The Risk Assessment completed by EMPCo for the Conway to Corsicana Testable Segment on March 15, 2011 included an Updated risk score, as of March 7, 2011 of D(542.8) 3(190) [See Tab G, page iii], indicating that the likelihood of an integrity failure with moderate consequences was remote. The actual failure resulted in Tangible consequences that were a category 1 (Critical), as defined by EMPCo [See Tab C].

Knowledge and concern about the condition of the Pegasus Pipeline ERW seam integrity was documented as early as 2004 during the Reversal Project design phase, and thereafter in internal communications, but there was no evidence that this knowledge was ever applied in the TIARA or IMP processes. EMPCo relied upon its TIARA/Integrity processes over corporate operational knowledge or knowledge from the Data Integration Team (DIT) and failed to identify the Tangible Threat that existed on the pipeline.

EMPCo's TIARA and IM processes failed to adequately characterize the risk of the Conway to Corsicana Testable Segment and failed to determine the existence of "Identified Threats" to or from the line segment, which resulted in EMPCo's failure to take appropriate risk reduction actions to manage the threat of a potential seam failure of the pre-70 ERW pipe. Evidence indicated that the desired outcome drove the analyses, where in fact, the analyses should have driven the outcomes, specifically in identification of risk factors, susceptibility to seam failure and fatigue analyses.

There was evidence of growth of the hook cracks as a result of the failures that occurred at lower test pressures than the pipeline had previously experienced [See Tabs F, E and H], along with other information contained in the 2006 metallurgical reports [See Tab F]. The conclusion in 2006 that the lower test temperatures as compared to 1991 testing were responsible for the failures at pressures lower than previously experienced on the pipeline are not supported by the metallurgical analyses [See Tab F]. Further, the test temperatures were within the design parameters of the pipeline's normal operating temperature range. It is interesting to note the reluctance of EMPCo to acknowledge that fatigue or defect growth occurred in its reluctance to classify pipe segments that should obviously be considered susceptible to seam failures as such.

While pressure-cycle-fatigue is one possible cause of the extension of hook cracks, it was not the only form of time dependent growth mechanism that could cause growth of the flaws and ultimate failure of the pipe in 2006 and 2013. However, EMPCO's IM procedures did not address any time dependent manufacturing-type failure mechanisms other than pressure-cycle-fatigue or selective seam (grooving) corrosion [See Tab D], and failed to effectively utilize the information contained within the 2006 metallurgical reports from the hydrotest failures, as well as the significant amount of industry research since 2003 [See Tabs A, E, H, and I] to make necessary decisions about the IM for the Pegasus Pipeline.

EMPCo's fatigue analyses did not conform to recommended best practices, and failed to consider the requirements for maximum reassessment intervals in the federal pipeline safety regulations. Further, PHMSA does not consider this an adequate method for determining "*if and when a TFI Tool must be run.*" The presence of the pre-70 ERW pipe, and its failure history was adequate information for PHMSA to consider it as requiring either a Subpart E hydrotest or internal inspection with a tool *capable of assessing seam integrity and of detecting corrosion and deformation anomalies*.

For modeling purposes, the largest remaining defect surviving the prior hydrotests would have been a more appropriately conservative starting point for the fatigue analyses [See Tab E]. To achieve this, higher CVN numbers should have been used to predict crack growth as recommended by Kiefner and Associates, Inc. (KAI), the PipeLife program developer. However, the only evidence of EMPCo's awareness of the CVN value's role in the remaining life calculations was that "*increasing the CVN number decreased the reassessment interval*," which was not an EMPCo desired result as discussed in internal communications. Using a smaller number for the CVN results in a smaller remaining defect having survived the hydrotesting, and thus more cycles required to grow the defect to failure, which results in a longer time before the next inspection.

Recommendations for the amount of data to be used for counting the pressure cycles to be used in connection with the PipeLife analyses were also not used by EMPCo [See Tab E]. As a result, it was not possible to evaluate whether or not the data was actually representative of the true operating conditions. It was noted that there was a significant change in the 2012 fatigue analysis inspection intervals which was a result of the operational changes after the 2009 system expansion, as indicated by the fatigue analyses that used pressure data from the month of May 2012. The appropriateness of the CVN values and pressure-cycle analyses are critical to achieve meaningful results [See Tabs E and H]. While the maximum time for reassessment would not have been extended beyond 68 months based upon the results of these analyses, there may be cases where the regulatory interval is in fact longer than the interval from the fatigue analyses, and an interval shorter than five years should be used, as appropriate.

Had EMPCo sought outside review or had in-house technical expertise in this area, PipeLife analyses might have used a higher CVN value than the value of 7 used by EMPCo (200 was recommended in the recent Battelle work by KAI, and 25 to 40 in the Baker Report). Further, the data used for the pressure cycle analysis would have been collected over the period of one year to ensure all seasonal variations were captured. The surge analyses that were performed in 2006 and 2009 both considered seasonal variations in the Pegasus pipeline operations. These variations should also have been captured in the fatigue analyses by using a rainflow counting method [See Tab H] for one year's worth of pressure data to capture the entire loading spectrum resulting from the seasonal operations of the pipeline.

In 2009, after addition/reactivation of pump stations and expansion of the flow capacity of the Pegasus Pipeline system, additional SFSA analyses were performed, along with supporting pressure-cycle-fatigue analyses [See Tabs D, E and G]. The 2009 SFSA analysis of the Conway to Corsicana Testable Segment again deemed the line not susceptible to long seam failure because EMPCo "*achieved successful hydrotests*" on the segment in 2006, and there was light to very light pressure cycling and no clear cut evidence of fatigue related failures in the 2006 metallurgical analyses.

The SFSA performed in 2011 on the same segment still failed to conclude that the ERW pipe in the pipeline was susceptible to long seam failure, but noted the "*circular logic*" [See Tabs D and G] of the flow chart used in the analysis, even though it was the same person performing the analysis and the same revision date of the flow chart that had been used in the previous two versions of the long seam failure susceptibility analyses [See Tab D]. However, this time it was recommended that a TFI run be performed in 2011 – 2012 based upon the 7.4 year retest interval determined in the Conway to Corsicana March 3, 2011 fatigue analysis.

The Risk & Integrity Specialist recommended that a TFI tool inspection be performed in the summer of 2011 for the Conway to Corsicana Testable Segment of the Pegasus Pipeline. The TIARA analysis was run with the assumption that the TFI tool inspection had been completed, and as a result, the TIARA process resulted in no Identified Threats [See Tabs C and G]. While TFI tools are good for longitudinal flaw detection such as grooving corrosion of the ERW seam, the types of defects that were identified in the 2006 hydrotest failure metallurgical reports were not likely to be detected by a TFI tool, and TFI was not an appropriate tool selection for the nature of the manufacturing flaws known to be present in the Patoka to Corsicana segment of the Pegasus Pipeline. EMPCo's tool selection process did not consider the previous defects or hydrotest failures, and the selection of the TFI tool was based upon past experience on other pipelines, cost and ease of use due to less stringent line condition and cleaning requirements than other tools, as stated by the EMPCo risk analyst.

Nonetheless, a Management of Change (MOC) document was generated on November 15, 2011 to reschedule the internal inspection by TFI tool to some time prior to December 31, 2012. The TFI tool inspection was ultimately performed on February 6, 2013. The reason cited for rescheduling the tool run was an "*effort to maintain the company's fiscal goals*." The document did not check the box that asked the questions as to whether or not the new interval will exceed 60 months, and stated "*that the change in date does not cause any safety, health or environmental issues related to the pipeline segment within the Pegasus crude system*." Additional internal documentation reflected the rescheduling of the inspection to the summer of 2012 due to "*budget constraints*," and relied upon the lowest predicted PipeLife retest interval of 7.4 years for the justification of the rescheduling of the TFI inspection for the segment. However, there were no further actions taken to reassess the risk with the change in the TFI schedule. The alternate threat analysis that EMPCo performed without the TFI tool run being performed in 2011 resulted in the identification of Manufacturing Threats on the Conway to Foreman segment, and should have triggered risk reduction actions by EMPCo.

EMPCo performed an in-line inspection using a TFI tool in 2010 on the Patoka to Conway Testable Segment. The record is unclear as to why the Patoka to Conway segment was scheduled before the Conway to Corsicana segment when the shortest reassessment interval was on the Conway to Corsicana Segment, as determined in the fatigue analyses. Further, the relative risk of the Patoka to Conway segment was roughly equal to the Conway to Corsicana segment, and neither risk assessment by EMPCo identified Tangible Threats in either testable segment. The Patoka to Conway relative risk score was Probability 522.7/Consequence 159.6 on August 15, 2011 - Risk Matrix (C4), whereas the Conway to Corsicana score was Probability 542.8/Consequence 190 on June 21, 2011 – Risk Matrix (D3), and would have ranked roughly equal in the EMPCo Risk Matrix. An informed reasonable review of the history of the two segments and the environmental receptors however, would have probably accorded first priority to the Conway to Corsicana segment [See Tab G].

The 2010 TFI tool run on the Patoka to Conway Testable Segment was completed within the required regulatory reassessment interval. The 2013 TFI run on the Conway to Corsicana Testable however was not. EMPCo was familiar with and relied upon PHMSA FAQs for guidance in application of the federal pipeline safety regulations, as demonstrated in internal communications about whether or not the Pegasus Pipeline had to by hydrotested before it was returned to service.

PHMSA's FAQ 5.9 on the Hazardous Liquids IMP website was last updated on October 23, 2001 and clearly stated the expectations that multiple assessment tools must all be completed within the required reassessment interval which shall not exceed 68 months. FAQ 5.9 reads as follows:

> ***5.9 Once baseline assessments are complete, will operators be able to use their continuing evaluation process to identify primary threats and schedule assessments accordingly, even if this means conducting metal loss and deformation inspections on different intervals?***
>
> *195.452 (j) (3) requires operators to use their risk analysis, and analysis of results from the last integrity assessment to determine the appropriate interval for conducting future integrity assessments. Where internal inspection is the chosen assessment method, completing the re-assessment will require that both a metal loss and deformation tool be run. Either in-line inspection tool can be run more frequently if threats to pipeline integrity indicate that differing frequencies are appropriate. However, both tools must be run within the required re-assessment interval.*

Additionally, the regulations at §195.452(e) require that *"An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule <u>on all risk factors</u> that reflect the risk conditions on the pipeline segment."* The timing of the reassessment shall not exceed 68 months. Based upon the baseline hydrostatic testing that was completed in 2006, the Conway to Corsicana Testable Segment maximum reassessment interval required the next assessment to be performed in the 2011 calendar year.

The reassessment methods for pre-70 ERW pipe are one of the two following options:

- Run an in-line inspection device(s) capable of detecting seam flaws, metal loss corrosion, and deformation anomalies, OR
- Perform a Subpart E hydrostatic test.

Based upon the 2006 hydrostatic failure metallurgical testing results [See Tab F], the best industry practices [See Tabs A, E and H], and the threshold of detection for the TFI tools used by EMPCo [See Tab C, page iii], EMPCo should have selected hydrotesting over inspection with the TFI tool for the reassessment in 2013.

Conclusions

EMPCo's management processes failed to identify the threat resulting from manufacturing defects on the failed pipeline segment. The management processes intended to address integrity threats related to pre-70 ERW pipe manufacturing defects were faulty, or not implemented correctly, or a combination of the two.

EMPCo's management processes failed to accurately characterize the risk, including both probability and consequences, of the Conway to Corsicana Testable Segment. Further, the segment was not prioritized above the Patoka to Conway segment for reassessment when it had a higher relative risk.

EMPCo failed to determine portions of the Pegasus Pipeline as *Susceptible to Seam Failure.* As a result, EMPCo took risk reduction and IM actions which were less effective to address the pre-70 ERW failure, including the failure to perform a reassessment of the Testable Segment within the maximum prescribed interval of not more than 68 months from the previous baseline assessment performed in 2006.

EMPCo failed to select the proper reassessment method in light of the information from previous hydrotest failures, and recommendations included in the technical report upon which EMPCo claims to have based their management of pre-70 ERW pipe integrity. The most appropriate selection for the method of reassessment would have been to perform a subpart E hydrotest of the pipeline segment between Conway and Foreman Pump Stations. Further, if use of an internal inspection tool was chosen over hydrotest; the use of UT, EMAT, or possibly another tool capable of detecting the types of defects known to be present in the Patoka to Corsicana segment of the Pegasus Pipeline should have been selected instead of the TFI tool used by EMPCo in 2013.

Had any one of these actions been executed properly, it would have been far less likely for the accident to occur, and thus are found to be contributory to the primary cause of the accident.

Pre-70 ERW Chronology

Tab A provides a chronology of relevant events and documents on the subject of pre-70 ERW Pipe. A chronology of the integrity management actions on the Pegasus Pipeline Patoka to Corsicana Segments is found in Tab G.

Early PHMSA (OPS) Actions

- January 1988 – The Office of Pipeline Safety (OPS) issued an Alert Notice to natural gas transmission and hazardous liquid pipeline operators to reevaluate pre-1970 ERW pipe, and to consider hydrostatic testing
- March 1989 - OPS issued a second Alert Notice reiterating the 1988 Alert Notice recommendations on hydrostatic testing and corrosion control for pre-1970 ERW pipe.
- Hazardous liquid pipeline safety regulations, from inception in 1970, required all newly constructed pipelines and pipelines that have been replaced, relocated or otherwise changed to be hydrostatically tested to at least 125 percent of their maximum operating pressure (MOP)
- Beginning in 1994, OPS issued a series of amendments to the hazardous liquid pipelines safety regulations, requiring pipelines that were constructed before the effective date of the regulations and had not been tested to 125 percent above their MOP to be so tested.
- Later, OPS issued a risk-based alternative rule which allowed operators to elect an approach that takes into account certain risk factors in evaluating the integrity of these hazardous liquid pipelines. All pre-70 ERW considered susceptible to longitudinal seam failure that was not reduced in MOP had to be tested. All pre-70 ERW pipe was deemed susceptible to longitudinal seam failures unless an engineering analysis showed otherwise. In conducting an engineering analysis the operator was to consider the seam-related leak history of the pipe and pipe manufacturing information as available, including the pipe steel's mechanical properties, including fracture toughness; the manufacturing process and controls related to seam properties, including whether the ERW process was high-frequency or low-frequency, whether the weld seam was heat treated, whether the seam was inspected, the test pressure and duration during mill hydrotest; the quality control of the steel-making process; and other factors pertinent to seam properties and quality.
- In 2000, Amendment 195-70 added Pipeline Integrity Management (IM) in High Consequence Areas (HCAs) regulations to 49 CFR 195. The original rulemaking included specific requirements for LF-ERW pipe assessment methods in 49 CFR 195.452 requiring that *"for low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure, an operator must select integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies."*
- In 2001, Amendment 195-74 modified the language to its present wording of; *"The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies."*

Technical Papers, Reports and Studies

In 2000, John Kiefner and Willard Maxey presented a paper titled "*Periodic Hydrostatic Testing or In-Line Inspection to Prevent Failures from Pressure-Cycle-Induced Fatigue*" (Kiefner-Maxey Paper). The Kiefner-Maxey Paper detailed the concept of crack growth from initial imperfections in steel pipelines in liquid service and discussed a technique to assist pipeline operators in addressing and controlling the phenomenon. The use of crack-growth models is important for determining the appropriate re-inspection interval for pipelines that may experience time-dependent failure mechanisms related to pressure-cycle fatigue or grooving corrosion, both of which are typical concerns for early vintage low frequency welded ERW pipe.

A subsequent paper by Kiefner and Maxey, *"The Benefits and Limitations of Hydrostatic Testing,"* was prepared to clarify the issues regarding the use of hydrostatic testing to verify pipeline integrity. This paper provided a summary of research conducted by the Battelle Memorial Institute (Battelle) in the early 1950s as Texas Eastern began to rehabilitate the War Emergency Pipelines. The data obtained from the Battelle research forms much of the basis for the current ASME B31.8 and B31.4 Code Requirements for hydrotesting in use today. During the study, hundreds of test breaks occurred which helped create the earliest knowledge of pre-50s low frequency welded ERW pipe failures. This paper also discusses the concepts of "pressure reversal," optimal pressure test levels, and prediction of sizing and remaining life of defects surviving hydrotesting.

John Kiefner presented a paper titled "*Dealing with Low-Frequency-Welded ERW Pipe and Flash-Welded-Pipe With Respect to HCA-Related Integrity Assessments*" at the ETCE ASME Engineering Technology Conference on Energy, February 2002, in Houston, TX (Kiefner Paper). The Kiefner Paper formed much of the hazardous liquids industry's basis for the handling of integrity concerns related to pre-70 vintage ERW pipe. The paper included subject matter to be used for the determination of whether or not a Seam-Integrity-Assessment Plan (SIAP) should be developed as part of an operator's Integrity Management Program (IMP) for High Consequence Areas (HCAs).

The Gas Research Institute commissioned a study and resulted in the report GRI-04/0178, "*Effects of Pressure Cycles on Gas Pipelines"* in September, 2004. Case studies of three gas pipelines and one liquid pipeline were included in this report written by John Kiefner and Michael Rosenfeld.

In 2004, PHMSA commissioned a study under contract with Michael Baker, Jr., Inc. in association with Kiefner and Associates, Inc. and CorrMet Engineering Service, PC for the OPS Integrity Management Program Delivery Order DTRS56-02-D-70036. This project resulted in the report titled "*Report OPS TT05 – Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation"* (Baker Study). The Baker Study further developed and included the Kiefner Paper concepts "*in an attempt to provide a standardized, systematic approach to evaluation of longitudinal seam integrity.*" A subsequent report titled "*Report OPS TT06 – Spike Hydrostatic Test Evaluation"* was also issued under the same PHMSA Delivery Order. The report included a specific section on the subject of Considerations for Pre-70 LF-ERW Pipe, as well as a discussion on sensitivity to pipe parameters that included the subject of fracture toughness.

Under contract to OPS, Contract No., DTFAAC05P02120, John Kiefner, with the assistance of the Interstate Natural Gas Association of America (INGAA), issued a final report on "*Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*," April 26, 2007. The report contains a compilation or the most common and most significant types of manufacturing defects that can be expected to exist in pipelines. The document includes discussions on three mechanisms known to cause a defect to grow larger after surviving a particular pressure level. The three mechanisms are; 1) quasi-stable ductile tearing at pressure levels closely approaching the failure pressures of the defect; 2) pressure-cycle-induced fatigue; and 3) pressure reversals. The paper contains numerous technical references on hydrotesting, pressure reversals, integrity characteristics of vintage pipelines, and various failure investigations.

ERW Seam Failure LPG Pipeline - Carmichael, MS

On November 1, 2007, the 12-inch diameter Dixie Pipeline owned and operated by Enterprise Products Operating Company was carrying liquid propane at about 1,405 psig when it ruptured near Carmichael, MS resulting in two fatalities and seven minor injuries. The pipeline was constructed of low frequency LF-ERW pipe manufactured in 1961 by Lone Star Steel Company. Prior to the failure there had been no long seam leaks or ruptures in the area, and the system experienced one 2-inch long non-reportable leak in the long seam in 1984. The original hydrostatic test after construction in 1961 resulted in 13 failures, ten (10) of which were failures of the ERW long seam. Subsequent hydrotesting in 1984, 2001, 2002 and 2007 resulted in further ERW seam splits at test pressures ranging from 1,670 to 1,960 psig. Metallurgical testing of the previous hydrostatic test failures determined all of the seam failures to be manufacturing defects including stitching, low ductility of the weld bond line, hook cracks, and cold welds. None of the failures showed any evidence of pressure-cycle-induced fatigue crack growth. The operator had experienced no in-service failures prior to the accident. The NTSB reported that *"accumulated data from the three in-line inspections of the [Dixie] pipeline and from the examination of the pipe joints that were removed and subjected to hydrostatic testing illustrate the limitations of current in-line inspection technology for detecting significant flaws in low-frequency ERW pipe."*

Ongoing PHMSA Pre-70 ERW Pipe Actions

After the 2007 ERW seam failure on the Dixie Pipeline, the National Transportation Safety Board's (NTSB) investigation report was issued on October 14, 2009 as NTSB Accident Report PB2009-916501. In that report, the NTSB recommended that PHMSA conduct a comprehensive study to identify actions that can be implemented by pipeline operators to eliminate catastrophic longitudinal failures in ERW pipe. NTSB issued Safety Recommendation P-09-1, *Safety and Performance of Electric Resistance Welded (ERW) Pipe* to PHMSA on October 27, 2009 wherein it recommended that PHMSA "*conduct a comprehensive study to identify actions that can be implemented by pipeline operators to eliminate catastrophic longitudinal seam failures in electric resistance welded pipe (ERW); at a minimum, the study should include assessments of the effectiveness and effects of in-line inspection tools, hydrostatic pressure tests, and spike pressure tests; pipe material strength characteristics and failure mechanisms; the effects of aging on ERW pipelines; operational factors; and data collection and predictive analysis."*

On May 26, 2011, PHMSA selected Battelle to conduct a comprehensive study (PHMSA ERW Study) identifying actions that can be implemented by pipeline operators to eliminate catastrophic longitudinal seam failures in ERW pipe. The "Study Team" includes Battelle, Det Norske Veritas (DNV), and Kiefner and Associates, Inc. (KAI). The ongoing activities of the PHMSA ERW Study Team and sub-task reports completed by Battelle and the companies on the Study Team are found on the PHMSA website.

In September 2011, the PHMSA ERW Study Team contacted pipeline operating companies to request ERW failure data for the PHMSA ERW Study. Data collected would not identify pipeline operators or dates of failures, but was intended to increase the knowledge and understanding of failures, and increase the database of ERW pipe long seam failure information.

Task Reports are posted on the Study website at: http://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390 and include a wealth of information, failure data, and research that has been completed to date.

Following the comprehensive study currently underway by Battelle, PHMSA will determine how to address the requirements of the second NTSB Safety Recommendation (P-09-2) where the NTSB recommended that "*based upon the results of the study from NTSB Open Recommendation P-09-1, PHMSA implement the actions needed*." It is anticipated that an additional year to 18 months after the study is completed would be required to fully implement the needed actions.

--end--

Operations Integrity Management System (OIMS)

Tab B provides a description of ExxonMobil's OIMS and relevant discussion related to OIMS and its role in two other significant accident investigations outside of the US federal pipeline safety regulatory regime.

The ExxonMobil Operations Integrity Management System (OIMS) is a Safety Management System that was put in place in the 1990s after the Exxon Valdez accident in Alaska, and is an ExxonMobil global process.

ExxonMobil describes its OIMS system as "*a process [that] requires continuous evaluation and improvement of management systems and standards as well as the involvement of every employee. It has established a common language for discussion and sharing of successful systems and practices among different parts of ExxonMobil's business.*"

ExxonMobil further describes the OIMS framework as having "*11 elements, each with clearly defined expectations that every operation must fulfill. Management systems put into place to meet OIMS expectations must show documented evidence of the following five characteristics:*

- *The scope must be clear and the objectives must fully define the purpose and expected results;*
- *Well-qualified people are accountable to execute the system;*
- *Documented procedures are in place to ensure the system functions properly;*
- *Results are measured and verified that the intent of the system is fulfilled; and*
- *Performance feedback from verification and measurement drives continuous improvement of the system.*

OIMS requires each operating unit to be assessed by experienced employee teams from outside that particular unit approximately every three years. Self-assessments are required in the other years."

The OIMS Elements are defined as: *(source: http://www.exxonmobil.com/Corporate/safety_ops_oims.aspx)*

"1. Management, leadership, commitment and accountability.
Employees at all levels are held accountable for safety, health and environmental performance.
2. Risk assessment and management.
Systematic reviews evaluate risks to help prevent accidents from happening.
3. Facilities design and construction.
All construction projects from small improvements to major new expansions are evaluated early in their design for safety, health and environmental impact.
4. Information and documentation.
Information that is accurate, complete and accessible is essential to safe and reliable operations.
5. Personnel and training.
Meeting high standards of performance requires that employees are well trained.
6. Operations and maintenance.
Operations and maintenance procedures are frequently assessed and modified to improve safety and environmental performance.

7. Management of change.
Any change in procedure is tested for safety, health and environmental impact.
8. Third-party services.
Contractors are important to safe operations.
9. Incident investigation and analysis.
Any incident, including a "near miss," is investigated.
10. Community awareness and emergency preparedness.
Good preparation can significantly reduce the impact of an accident.
11. Operations integrity assessment and improvement.
A process that measures performance relative to expectations is essential to improved operations integrity."

ExxonMobil's OIMS was the subject of another accident investigation when in Australia in 1998 there was a significant accident at the Esso Longford Gas Plant. An Australian Royal Commission investigated the accident and as part of the findings observed the following about OIMS;

Evidence was given that OIMS was a world class system and complied with world's best practice. Whilst this may be true of the expectations and guidelines upon which the system was based, the same cannot be said of the operation of the system in practice. Even the best management system is defective if it is not effectively implemented. The system must be capable of being understood by those expected to implement it.

Esso's OIMS, together with all the supporting manuals, comprised a complex management system. It was repetitive, circular, and contained unnecessary cross-referencing. Much of its language was impenetrable.

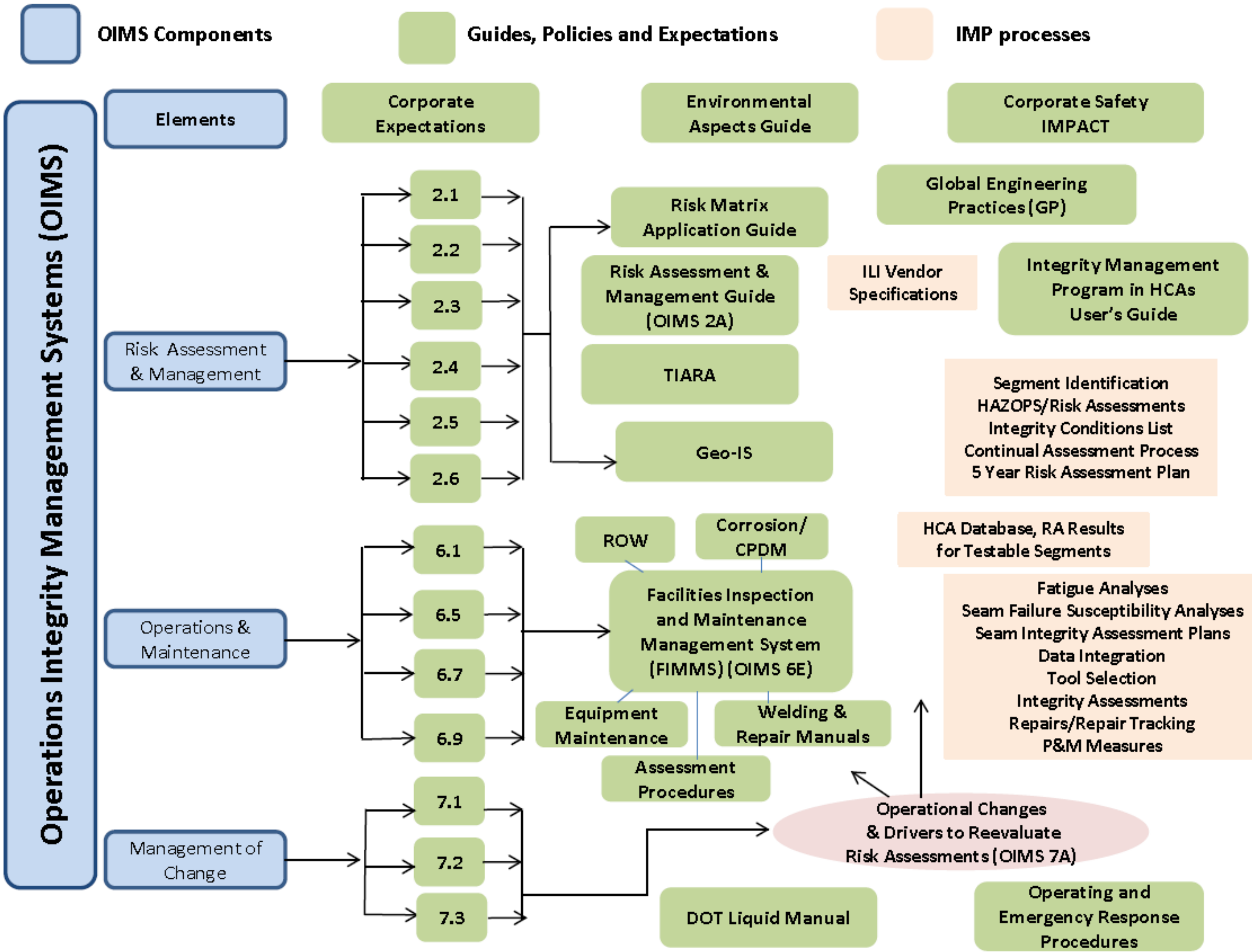
The Commission gained the distinct impression that there was a tendency for the administration of OIMS to take on a life of its own, divorced from operations in the field.

However, the fundamental shortcoming was in the implementation of OIMS, as seen in the inadequate state of knowledge of Esso personnel of the hazards associated with loss of lean oil circulation in GP1 and of the actions which could be taken to mitigate such hazards.

Reliance placed by Esso on its OIMS for the safe operation of the plant was misplaced. The accident on 25 September 1998 demonstrated in itself, that important components of Esso's system of management were either defective or not implemented.

After the BP Deepwater Horizon Accident in the Gulf of Mexico, Rex Tillerson, Chairman and CEO of Exxon Mobil Corporation provided testimony to the National Commission on BP Deepwater Oil Spill and Offshore Drilling. Mr. Tillerson touted the OIMS process heavily, and stated that ***"ExxonMobil believes that incidents like the Deepwater Horizon spill should not happen if industry best practices are followed."*** He further stated that ExxonMobil is ***"constantly learning and analyzing – by looking to best practices in other organizations, examining near misses in our own organization – that we continually improve our performance."***

Key OIMS Elements and their relationship to some of the many processes EMPCo has in place to address the requirements of the federal pipeline safety regulations for *Pipeline integrity management in high consequence areas* for the Pegasus Pipeline are shown in the following graphic:



The first and last Elements in OIMS are described by ExxonMobil as the "book-ends" of OIMS with Element 1, *Management Leadership, Commitment and Accountability* being the "driver" and Element 11, Operations Integrity Assessment and Improvement providing the feedback mechanism to ensure continuous improvement. The 11 Elements and their 65 Corporate Expectations are the basis for the business unit's detailed OIMS Guidelines. These Guidelines describe how each business unit addresses the 65 Corporate Expectations relevant to the business unit's operations. Further, there are discrete comprehensive Management Systems that provided step-by step details of OIMS execution at the site level – such as the EMPCo IMP User's Guide and FIMMS. Collectively, this is the set of processes in place to operate and maintain the Pegasus Pipeline.

Mr. Tillerson provided the following in his closing statement to the U. S. House of Representatives Energy and Environmental Subcommittee on June 15, 2010:

> *"These facts* [the importance of oil and gas activity in the Gulf of Mexico to the American People] *show how critical it is that all industry participants have the trust of the American people. We can secure that trust if we take the time to learn what happened and develop our response appropriately to ensure that every participant acts responsibly, learns the right lessons and upholds the highest standards. The American people deserve nothing less."*

EMPCo, through OIMS and clear leadership expectations should continuously improve their processes and performance from industry experience, as well from incidents within their own organization. However, EMPCo failed to learn from two such accidents prior to this release. Instead, EMPCo insisted that their practices were appropriately founded on a PHMSA sponsored study from 2004 that established the basis for the handling of the subject of susceptibility to seam failure for pre-70 ERW pipe when PHMSA questioned EMPCo in the May 3, 2013 CAO Hearing on why it had not identified seam integrity as a threat on the Pegasus Pipeline.

The 2007 Carmichael, MS accident on the Dixie Pipe Line [See Tab A] provided a case study for EMPCo that should have, at a minimum, caused EMPCo to reconsider their processes and incorporate lessons learned from a very similar failure on a system with very relevant history to the Pegasus Pipeline.

The 2012 Torbert, LA accident [See Tab J] on EMPCo assets should have, at a minimum, caused EMPCo to reconsider their management practices for pre-70 ERW pipe where a failure occurred on a pipe segment that was considered by EMPCo to be Susceptible to Seam Failure. Instead, the Root Cause Failure Analysis for that event deemed the failure to be "unique" and placed reliance upon the "*Company's Integrity Management Program already, in place, EMPCo does not believe that these findings would likely be applicable to any other locations beyond the Affected Pipeline.*"

The findings of the Esso Royal Commission could as easily be used to describe the failure of the management systems in place that were intended to identify and manage the threats related to the ERW long seam failure susceptibility of the Mobil Pegasus Pipeline. The reliance upon the OIMS and TIARA/IMP processes to identify and manage risk relative to the Pegasus Pipeline ERW long seam integrity "was misplaced."

--end--

Threat Identification and Risk Analysis (TIARA) Model

Tab C is a discussion on the EMPCo TIARA model and its use in integrity management decisions for assets managed under the EMPCo integrity management processes.

TIARA is used in the risk management processes to determine a single risk score for the entire "Testable Segment" and correlate the score to the EMPCo Risk Matrix. The process overview for locating threats to pipeline integrity and the relative risk of pipeline Testable Segments is described in the TIARA manual as follows:

> *Threat types and the associated inputs to their determination are done in accordance with Appendix A of ASME B31.8S. Additional data inputs and calculation fundamentals are based on the Pipeline Risk Management Manual, 3rd Edition, by W. K. Muhlbauer. The likelihood of each threat is evaluated independently based on its conditions relative to the Company average. Finally, to determine a threat's classification, the consequences attributable with that threat are compared to its likelihood of being present.*
>
> *Pipeline relative risk is determined as the length weighted summation of the threats and consequences. A single score is given for the entire Testable Segment and is correlated to the EMPCo Risk Matrix. In recognition of the potential for a short segment of pipe with a significant threat to exist, the risk level assigned by the Risk Matrix also includes consideration for Threat Levels.*
>
> *As described above, the threat and risk models are interrelated; but are not recursive. Threat level incorporates the risk assessment consequence level and risk assessment includes the potential for a threat to be present. Therefore, the models function together and are singularly referred to as the Threat Identification and Risk Assessment (TIARA) model.*

Based upon two validations, the TIARA model was correlated to the EMPCo Risk Matrix and the following values were used to correlate the TIARA output values to the ExxonMobil Risk Matrix found in OIMS Element 2.

Consequence – Theoretical Range: 0 - 1320

- Category I ≥ 400.0
- Category II ≥ 275.0 & < 400.0
- Category III ≥ 175.0 & < 275.0
- Category IV < 175.0

Probability – Theoretical Range: 0 – 900

- Category 'A' < 200
- Category 'B' ≥ 200 & < 400
- Category 'C' ≥ 400 & < 525
- Category 'D' ≥ 525 & < 700
- Category 'E' ≥ 700

EMPCo's experience with its TIARA software in its IMP decision processes resulted in the following information being incorporated into the EMPCo TIARA User Manual;

> *While this model works quite well at comparing the risk of a large number of EMPCo pipeline segments, it is less adept at identifying specific integrity threats to each of those segments. Other models, such as ASME B31.8S, offer clearer insights into the specific integrity threats for a given pipe segment.*
>
> *Therefore, the Testable Segment risk assessment result will provide a single length weighted score with it's corresponding EMPCo Risk Matrix cell assignment and a list of Identified Threats, if any.*
>
> *Because of the length weighting, it is possible for an Identified Threat to be present and the Testable Segment risk level to be low. To ensure that Identified Threats receive appropriate management notification and action, any Testable Segment with an Identified Threat is treated, at a minimum, as a Lower-Moderate risk. Management notification and action taken is to be completed in accordance with OIMS System 2A procedures.*

The *OIMS System 2A procedures* are covered by OIMS Element 2 – Risk Assessment and Management. The TIARA User Manual incorporates the EMPCo Risk Matrix into TIARA wherein the User Manual states that *"A length weighted risk score that can be correlated to the EMPCo Risk Matrix will be developed for each Testable Segment. In addition, for each intermediate segment within the Testable Segment, a ranking of threats- including Identified Threats -will be available. It is the identification of threats, which ensures that very short segments of significant threat are not diminished solely due to their length."*

The term "Identified Threat" was used by EMPCo to describe those threats that met the criteria of the upper right hand corner of the matrix in Table 4, equivalent to the OIMS Risk Matrix Threats that require Risk Reduction measures be implemented.

5.1 Identifying Threats:

Based on the probability of having an Integrity Threat with an elevated consequence, a Threat for further action is identified. Table 4 summarizes the combinations of probabilities and consequences that identify such a Threat.

Potential Consequences of Integrity Threat	Probability of Integrity Threat: High	Moderate	Low
Tangible	Identified Threat	Identified Threat	Not an Identified Threat
Moderate	Identified Threat	Not an Identified Threat	Not an Identified Threat
Lower	Not an Identified Threat	Not an Identified Threat	Not an Identified Threat

Table 4:
Conditions Identified as Threats

However, to be 'eligible' for consideration as an "Identified Threat," the risk drivers (Primary Loads and Resistances) are reviewed to locate any that are more than one standard deviation away from the Company average as shown in Figure 1, Threat Identification Process. Secondary Loads and Resistances are reviewed to locate any that are two or more standard deviations away from the Company average. If none exist, then the line segment being analyzed is determined to not have significant Threats relative to other EMPCo pipelines.

Only pipeline locations with 'High' or 'Moderate' probability of being Integrity Threats are evaluated for their potential consequences. Since there were no locations meeting these criteria on the Patoka to Corsicana segment of the Pegasus Pipeline in any of the analyses performed from 2005 to 2012, no evaluation of potential consequences was required.

All of the nine threats are calculated at every analysis segment with the numerical scores assigned. Based on how the analysis segment value compares to the Company average, a likelihood of that threat being present at that analysis segment is determined. Since the likelihood determination is made relative to Company averages, the classification in one area can change if risk reduction action is taken at other Company locations.

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The EMPCo process of Individual Threat Identification was convoluted. The Threat Identification Process flow chart is depicted by Figure 1.

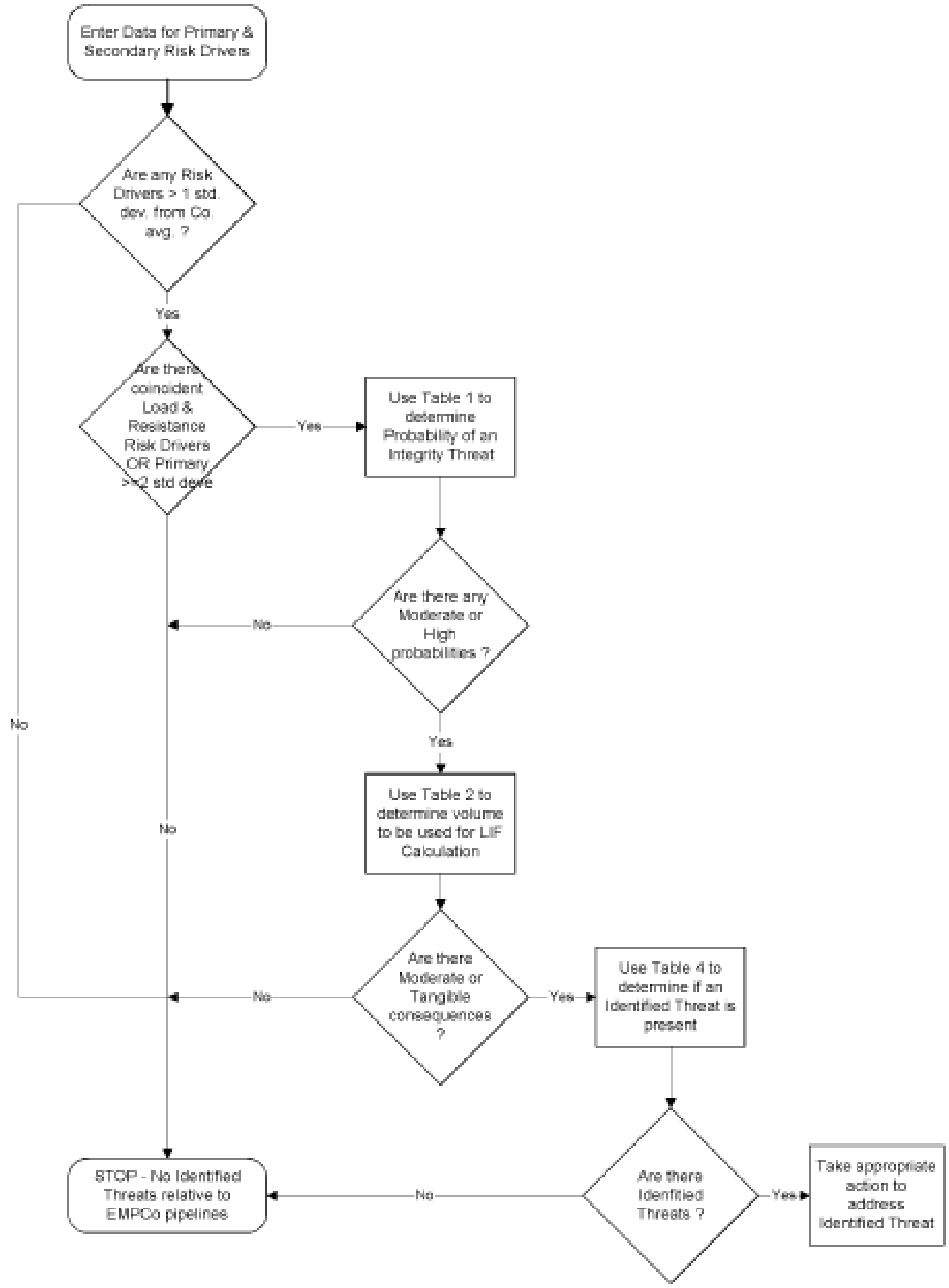

Figure 1: Threat Identification Process

A sampling of some of the sub-processes shown in Figure 1 are described in the following excerpts from the TIARA User's Guide included Individual Threat Determination, Integrity Threat Probability Determination using

Table 1 and the classification of conditions on the pipeline as Tangible, Moderate and Lower Threats in Table 4 to determine further action.

3.1 Individual Threat Determination:

Primary Loads and Resistances are reviewed to locate any that are more than 1 standard deviation or more away from the Company average. Secondary Loads and Resistances are reviewed to locate any that are 2, or more, standard deviations away from the Company average. If none exist, then the line segment being analyzed is determined to not have significant Threats relative to other EMPCo pipelines.

Based on field validation of the model, it was also recommended that any Primary Load or Resistance that is more than 2 standard deviations be shown as an Integrity Threat. This is to be done regardless of a concurrent counter force being present.

3.2 Integrity Threat Probability Determination:

Pipeline locations where identified Load and Resistance Risk Drivers are found to coexist are qualitatively evaluated using Table 1. If no such locations are found, then the line segment being analyzed is determined to not have significant Threats relative to other EMPCo pipelines. Locations with 'High' or 'Moderate' probability of being Integrity Threats are evaluated for their potential consequences.

		Loads						
		Primary			Secondary			n/a
		Heavy	Multiple Increased	Increased	Heavy	Multiple Increased	Increased	None
Resistances: Primary	Weak	High	High	High	High	Moderate	Moderate	Moderate
	Multiple Decreased	High	High	High	Moderate	Moderate	Moderate	Low
	Decreased	High	High	Moderate	Moderate	Moderate	Moderate	Low
Resistances: Secondary	Weak	High	Moderate	Moderate	Moderate	Moderate	Low	Low
	Multiple Decreased	Moderate	Moderate	Moderate	Moderate	Low	Low	Low
	Decreased	Moderate	Moderate	Moderate	Low	Low	Low	Low
Resistances: n/a	None	Moderate	Low	Low	Low	Low	Low	Low

Table 1:
Qualitative Threat Likelihood

A specific example of the failure of the threat identification process in context of the Pegasus Pipeline was the fact that EMPCo did not identify any threats on the Conway to Corsicana Testable Segment. Specifically, EMPCo determined that there was no threat related to Manufacturing or Seam Integrity using the TIARA Model and its associated processes for the Conway to Foreman (2007 assessment) or Conway to Corsicana (2011 assessment)

Testable Segments. The TIARA model inputs asked the subjective question about '*How likely is it that this section of pipe will be susceptible to a long seam failure under the current operating conditions*?' On a scale of '*Very Improbable'* with a value of 0.95, to '*Almost Certain*,' with a value of 0.05 the answer chosen was *'Possible'* with a value of 0.6 which further caused the threat to be minimized from its true potential. A more reasonable value from PHMSA's point of view was "*Likely*" at a value of 0.25. The score given for the value of the SFSA was *'Outstanding'* a value of 0.99, because it was 'new.' However, in PHMSA's opinion, this was more appropriately '*Adequate*,' a value of 0.56, because of the failure to incorporate new information from industry research and the 2005-2006 metallurgical reports.

The analysis was performed with no Manufacturing Threats identified in March 2011. This was a direct result of the decision to base the analysis on the TFI assessment as having already been completed, even though it was not expected to be run until that summer and ultimately was not run until February 2013. The effect of this on the overall Risk Score was minimal, as predicted by the User Guide. What it did cause to occur was the Manufacturing Threat that would have been an "Identified Threat" 'went away,' and the result was no Identified Threats being elevated to Management for action (see page ix, this tab for further details). Exacerbating this even further was the delay of the TFI tool run due to fiscal reasons, and the failure of the IM personnel to recognize the effect on the Threat Identification and Risk Assessments that had been performed with the reliance upon the assumption that the TFI tool run would be performed in the summer of 2011 when the MOC Form was prepared in November 2011.

Furthering under-valuation of the calculated risk for the Conway to Corsicana Testable Segment was the EMPCo TIARA Model's failure to identify key receptors on the consequence side of the risk calculation. The receptors failed to include drinking water supplies, commercial waterways, and populated areas in the Leak Impact Factor Table under the category of sensitive receptors. These would be minimum expectations to meet U.S. federal pipeline safety regulations under the IMP HCA definitions. The pipeline crosses a very sensitive receptor - the Lake Maumelle Watershed, a(b) (7)(F) [redacted] for the State of Arkansas, and was not captured by the options available in the TIARA Leak Impact Factor Table, even though the Data Integration Team (DIT) was aware of its presence and sensitivity.

Form 6.1, completed on June 21, 2011 to document the Preventive and Mitigative Actions Evaluation relied upon TIARA for "specific HCA or 'Identified' or significant threat," identification and while the DIT documented the sensitivities related to the Lake Maumelle Watershed, the summary stated that the DIT members agreed with the TIARA/Integrity process results. Evaluation of the Risk Factors in Section 4 relied upon TIARA input and

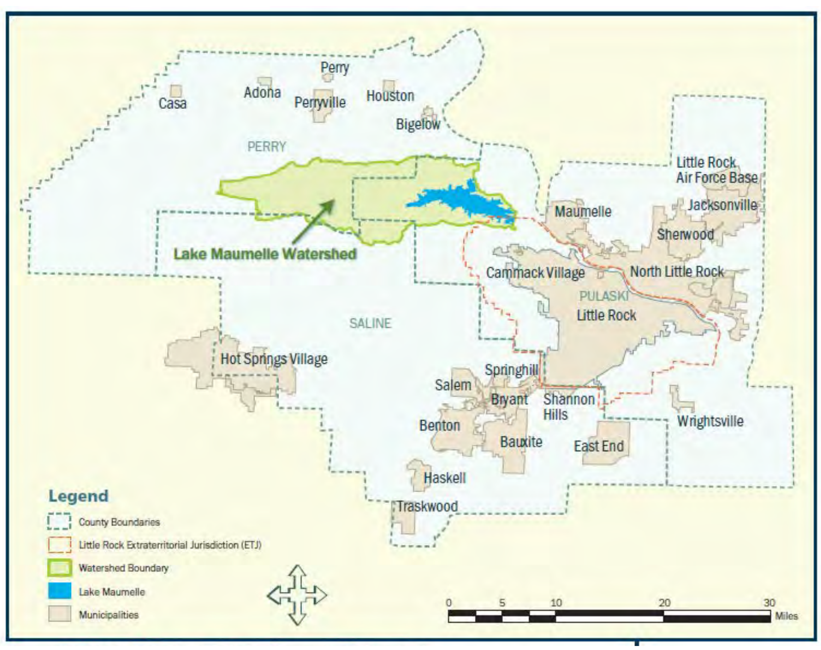

Figure X – Vicinity Map for Lake Maumelle Watershed

results, including waterways, ditches and conduits and terrain leading to HCAs. The TIARA results for the consequences of a spill on this Testable Segment were scored at 190 which equated to a low Moderate Consequence category in the EMPCo Risk Matrix.

The EMPCO Integrity Management personnel's manipulation of the TIARA process when the desired results were not achieved was identified in internal communications that stated "*we might do a couple of runs to find out how to handle them "IF" they have a negative impact on the risk score or threat results.*" The internal communication went on to state:

> #1.)
> We changed the answer to the question asking if we ran a crack tool from YES (for Pat-Con) to NO (for Con-Cors). We do plan to run a crack tool, maybe this year, on the Conway to Corsicana segment. If "NO" results in Manufacturing Threats or a worse risk score (than the D3 in 2006 or the C4 we just got on Pat-Con) then we'll also want to run it with a "YES" answer. Depending on what the difference in scores is we may use both so we can meet Discovery with the worse one , and then show what the score will improve to after a crack tool run .
>
> OR, if the "NO crack tool" score is totally unreasonable we may just leave the answer as YES and use the "with crack tool score" going forward anyway since it will represent the future situation and save everyone a bunch of angst and paperwork. Just might need to see both to figure out what to do.
>
> OR, if the score is still acceptable (D3 or C4) then we'll leave the NO answer as is and go with that.

A score of D3 or C4 is an acceptable level of risk based upon the EMPCo Risk Criteria in OIMS and the various resultant versions of that matrix as implemented throughout its business units. A Probability Category of D is considered a Remote possibility, and C is considered an Occasional possibility in the EMPCo Risk Matrix. The EMPCo Risk Matrix Severity Categories are 1 through 4, with 4 being the lowest, categorized in order of severity as Critical, Serious, Moderate, and Minor respectively. In the EMPCo IMP and TIARA processes, the Consequences were regrouped into three categories as follows:

Consequence Description		Category	Leak Impact Factor Range	
	Tangible	I	≥ 400	
	Tangible	II	≥ 275	< 400
	Moderate	III	≥ 175	< 275
	Lower	IV	< 175	

EMPCo utilized data from EMPCo's failure experience, and hazardous liquid accidents reported to PHMSA between 1985 through 2003 where the Tangible consequences defined above were met. The historically low frequency of 'Tangible' events for hazardous liquids pipelines further reduces the likelihood calculation in the probabilistic calculations of the TIARA model. The model has not been updated to include new data since 2003.

A score of D3 or C4 was an acceptable risk level with review by management and was equated with no Tangible Threats having been identified. The next level higher required management re-evaluation, and the highest levels of risk in the matrix (A1, A2, A3, B1, B2, C1) required EMPCo to implement countermeasures that reduce risk to an SSR1 of a level 2 at a minimum. In this light, one might consider that process "*a bunch of angst and paperwork*" was something to be avoided by personnel carrying out the IM risk assessment recommendations, as previously noted in EMPCo internal communications.

		Probability of Integrity Threat		
		High	Moderate	Low
Potential Consequences of Integrity Threat	Tangible	Identified Threat	Identified Threat	Not an Identified Threat
	Moderate	Identified Threat	Not an Identified Threat	Not an Identified Threat
	Lower	Not an Identified Threat	Not an Identified Threat	Not an Identified Threat

EMPCo defined an "Identified Threat" as either a 'Tangible' consequence having a Moderate or High likelihood of occurrence, or a 'Moderate' consequence with a High likelihood of occurrence.

A 'Tangible' consequence is defined by EMPCo as:

1) Any fatality or injury
2) Fire or explosion regardless of duration
3) Any evacuations
4) Widespread and/or enduring environmental damage requiring activation of emergency response beyond the local region
5) All releases of 1,000 bbls or more
6) Asset loss in excess of $1M

The TIARA manual stated that for relative calculation purposes, a Tangible Consequence is modeled as a rupture type release, which is further modeled as a release equivalent to 1 hour full mainline flowrate.

'Lower' Consequences are defined by EMPCo as:

1) No impacts on public
2) No impacts to personnel
3) Minimal environmental impact and addressed by local area personnel
4) Release volume below regulatory reporting requirements
5) Asset loss below $500k

'Moderate' Consequences are defined as all others between 'Tangible' and "Lower.' PHMSA would consider these appropriate designations and finds them to be typical of other operator's programs.

One TIARA process about which PHMSA has concerns is the Qualitative Threat Likelihood. Risk Ranking of Loads and Resistances relies upon the answering of a set of subjective questions for Leak Impact Factors that can be manipulated easily by users of the process, and where in fact it would appear that a breakdown occurred in the Threat Identification process for the Conway to Foreman Manufacturing Defect Threat. This process uses the Table 1: Qualitative Threat Likelihood matrix and the analysis of loads and resistances coupled with statistical calculations to determine the relative risk of the loads and resistances compared to the company averages. This process culminates in the Individual Threat Determination and further probabilistic analysis of Integrity Threat Probability.

The March 1, 2011 run of the analysis for Manufacturing Threats was performed. The analysis assumed that a TFI Tool Inspection was not performed and resulted in the following at the failure site (STA 16621+46):

17009
ss_id: 17010
testable_segm CONWAY TO
ent_name_des CORSICANA
c: 20"

Begin Station	End Station	Classification	Threat Type	Consequence	Deviations from Mean
16245+58.9	16470+01.6	Integrity	Moderate	196.650	1.00
16470+01.6	16482+31.1	Integrity	Moderate	242.250	1.00
16482+31.1	16513+20.5	Integrity	Moderate	196.650	1.00
16513+20.5	16513+37.9	Integrity	Moderate	155.250	1.00
16513+37.9	16515+12.1	Integrity	Moderate	196.650	1.00
16515+12.1	16519+23.3	Integrity	Moderate	155.250	1.00
16519+23.3	16587+47.6	Integrity	Moderate	196.650	1.00
16587+47.6	16587+93.2	Identified	Moderate	403.650	1.00
16587+93.2	16604+20.4	Integrity	Moderate	196.650	1.00
16604+20.4	16605+06.3	Identified	Moderate	403.650	1.00
16605+06.3	16626+36.9	Integrity	Moderate	196.650	1.00
16626+36.9	16737+83.3	Identified	Moderate	403.650	1.00
16737+83.3	16773+50.7	Integrity	Moderate	196.650	1.00
16773+50.7	16832+80.9	Integrity	Moderate	155.250	1.00

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When the analysis was re-run on March 4, 2011 with the assumption that a TFI Tool Inspection had been performed (it was planned for the summer of 2011), the results were as follows:

17009
ss_id: 17010
testable_segm CONWAY TO
ent_name_des CORSICANA
c: 20"

Begin Station	End Station	Classification	Threat Type	Consequence	Deviations from Mean
16245+58.9	16513+20.5	None	None	171.529	.00
16513+20.5	16513+37.9	None	None	135.418	.00
16513+37.9	16515+12.1	None	None	171.529	.00
16515+12.1	16519+23.3	None	None	135.418	.00
16519+23.3	16587+47.6	None	None	171.529	.00
16587+47.6	16587+93.2	None	None	352.086	.00
16587+93.2	16604+20.4	None	None	171.529	.00
16604+20.4	16605+06.3	None	None	352.086	.00
16605+06.3	16626+36.9	None	None	171.529	.00
16626+36.9	16737+83.3	None	None	352.086	.00
16737+83.3	16773+50.7	None	None	171.529	.00
16773+50.7	16832+80.9	None	None	135.418	.00
16832+80.9	16898+50.1	None	None	171.529	.00
16898+50.1	16898+61.6	None	None	135.418	.00

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The first analysis resulted in Identified Threats of a Moderate Type. The March 2011 EMPCo IM internal communications indicated that by using the second run the Identified Threats for Manufacturing 'went away.' The TIARA run was completed with TFI Tool being run, and the EMPCo IAD Form 3.2 completed on March 15, 2011 used the version without Identified Threats, and stated that by year end a seam assessment should be performed. The TFI Tool run was not actually completed until February 6, 2013.

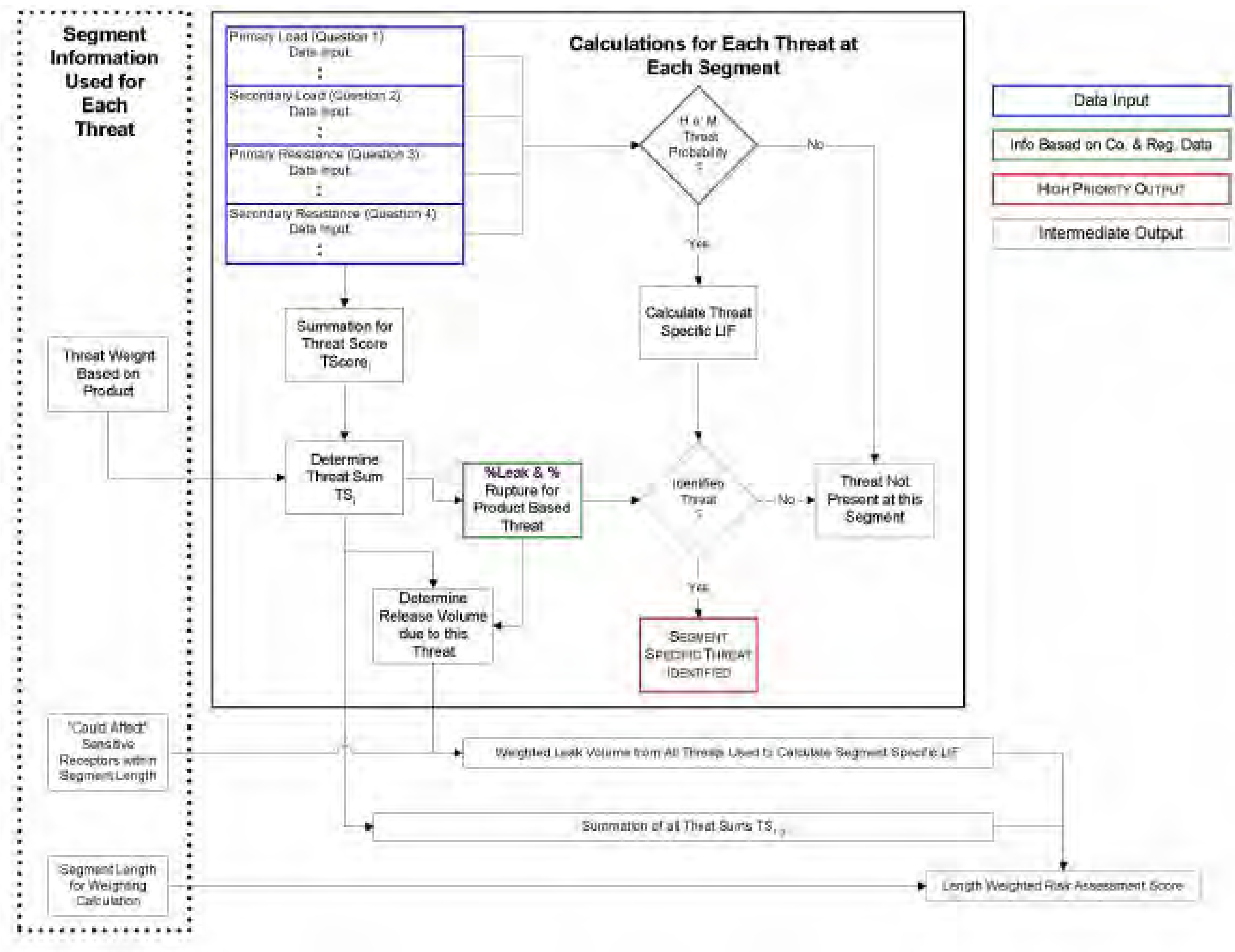


Figure 2: Data and Calculation Flow Through the Risk Assessment Process

EMPCo's TIARA Manual *Figure 2: Data and Calculation Flow Through the Risk Assessment Process* illustrates the manner in which the data flows through the Threat Model into the Risk Assessment process for each of the nine threat categories found in ASME B31.8S as part of the model algorithm.

The TIARA process was extremely detailed, and complex. Internal communications indicated that EMPCo Integrity Management personnel found TIARA to be counterintuitive and difficult to use as discussed in internal communications and documented in analyses. Analyses were performed multiple times to see how various inputs affected the Risk Scores for different answers to the subjective and objective questions in the TIARA template. The Data Integration Team members relied upon the model and EMPCo IMP processes over their own knowledge and judgment, possibly out of the inability to navigate the complexities of the processes and sub-processes, coupled with the significant effort it took to complete a run of the model, as documented in the internal communications between EMPCo integrity management personnel. Thresholds triggering actions to be taken for risk reduction were sufficiently high such that ultimately no action was taken.

For example, when evaluating the value of risk reduction actions by adding a valve or emergency flow restricting device (EFRD) in the EFRD evaluation required by 49 CFR 195.452(i), "*A significant change in consequence must move a lower level of the Risk Matrix or move 50% or more within the same cell of the Risk Matrix"* and if this criteria was not met, no further action was necessary. When evaluating whether or not to add valves for the protection of HCAs, a significant reduction in volume of 50% or greater was required in a segment to take further action. The Conway to Corsicana Testable Segment was evaluated against these criteria in 2011, and while the Data Integration Team (DIT) noted the sensitivity of the Lake Maumelle watershed and Cedar Creek Reservoir, Form 6.2 documented the following benefits, but determined that there was no significant change in the risk reduction score, and the valves were not added;

> *Reducing any of the spill volumes with a check or ROV would not significantly reduce the modeled risk or consequences as defined by the 50%/50% criteria and modeling with a IBRA/TIARA. However, the DIT/LRMT is familiar with extra sensitivities around the Lake Maumelle watershed area and Cedar Creek Reservior area such that the proposed EFRD sites at MP-308.94, MP-299.4, MP-295.5 and MP-29.94 are worth taking a closer look at to determine the cost/benifit and possibly performing a senario based risk assessment to see if they can be justified. Both lakes are public water supplies and are experiencing ongoing 3rd party development and/or activity.*

A simple spreadsheet analysis of the segments, side by side would have identified the confluence of integrity threats and receptors in the Foreman to Conway segment if EMPCo's processes were simplified, as demonstrated in the Summary of Integrity and Operations Events in Tab G. The Conway to Foreman Testable Segment had the highest hydrotest failure rate, an in-service leak, the most actionable repairs from the 1999-2001 baseline assessments, and the Lake Maumelle Watershed.

While PHMSA recognizes that this sort of analysis is impractical on a large scale, it was this sort of focused, practical review that was warranted as part of the Data Integration processes to ensure the appropriate prioritization of reassessments. The Conway to Foreman segment was objectively a higher risk segment when the summary is studied, and an appropriate assessment capable of assessing seam integrity and of detecting corrosion and deformation anomalies should have been performed on this segment before the Patoka to Conway Segment as borne out by the details in Tab G.

The cumulative effect of the EMPCo TIARA and associated IMP Processes was a set of manuals, processes, flow charts, questionnaires, analyses, and decisions - including the voluminous TIARA Manual that ultimately failed to identify the Manufacturing Threat and Tangible consequences associated with the Mayflower failure on March 29, 2013.

-- end --

Seam Failure Susceptibility Analyses (SFSA)

Tab D is a description of the EMPCo processes related to SFSAs, and particularly the SFSAs performed for the Pegasus Pipeline.

EMPCo did not consider the Pegasus Pipeline "Susceptible to Seam Failure." The definition of failure susceptibility was introduced in the federal pipeline safety regulations in 1998, as part of the risk-based alternatives to pressure testing of older hazardous liquid and carbon dioxide pipelines wherein §195.303 states (emphasis added):

(c) The program under paragraph (a) of this section shall provide for pressure testing for a segment constructed of electric resistance-welded (ERW) pipe and lapwelded pipe manufactured prior to 1970 susceptible to longitudinal seam failures as determined through paragraph (d) of this section. The timing of such pressure test may be determined based on risk classifications discussed under paragraph (b) of this section. For other segments, the program may provide for use of a magnetic flux leakage or ultrasonic internal inspection survey as an alternative to pressure testing and, in the case of such segments in Risk Classification A, may provide for no additional measures under this subpart.

(d) ***All pre-1970 ERW pipe and lapwelded pipe is deemed susceptible to longitudinal seam failures unless an engineering analysis shows otherwise****. In conducting an engineering analysis an operator must consider the seam-related leak history of the pipe and pipe manufacturing information as available, which may include the pipe steel's mechanical properties, including fracture toughness; the manufacturing process and controls related to seam properties, including whether the ERW process was high-frequency or low-frequency, whether the weld seam was heat treated, whether the seam was inspected, the test pressure and duration during mill hydrotest; the quality control of the steel-making process; and other factors pertinent to seam properties and quality.*

The preamble to the rulemaking stated that *"Highest priority is given to the Pre-1970 electric resistance welded (ERW) and lapwelded pipelines susceptible to longitudinal seam failures … because of their combination of probability of failure and potential for larger volume releases as evidenced by historical records."*

EMPCo completed hydrostatic testing of the Pegasus Pipeline in 1991, as required by revisions to 49 CFR 195 which required pressure testing older (steel interstate pipelines constructed before January 8, 1971) hazardous liquid and carbon dioxide pipelines. During that testing in 1991 there were 5 documented test failures, four of which were due to seam failures, and three of which were in the Conway to Foreman segment of the Pegasus Pipeline. (The other 2 test failures were on the Corsicana to Beaumont portion of the line, also known as the Southern Segment of the Pegasus Pipeline). This experience and the regulatory language adopted in 1998 should have been adequate information for EMPCo to deem the Pegasus Pipeline susceptible to longitudinal seam failures in the absence of engineering analyses demonstrating otherwise.

With the addition of the Pipeline Integrity Management in High Consequence Areas rulemaking in 2000, the additional requirements for assessment of pre-70 ERW pipe was incentive for operators to evaluate whether or not their Pre-70 ERW pipe was in fact susceptible to seam failure. Not all pipe manufactured prior to 1970 exhibits the same failure susceptibility, but the pre-50 LF-ERW Youngstown steel used in the Pegasus Pipeline was generally accepted as having manufacturing defects [Referenced studies and data collections – Tab A], and the 1991 test failures were confirmation of such conditions being present in portions of the Pegasus Pipeline. EMPCo should not have been questioning whether or not this pipeline was in fact susceptible to seam failure. Further, EMPCo has not presented PHMSA with an engineering analysis supporting its position that demonstrates otherwise.

EMPCo's IMP incorporates the work of John Kiefner, as presented in a technical paper in 2002 (Kiefner Paper - Tab A), where a process for classifying pre-70 ERW pipe was developed for pipeline operators to determine whether or not their ERW pipe needed to be included in a baseline assessment plan. PHMSA would most likely consider this an appropriate method for a pipeline operator that did not have the material characteristics, operating and test failure history exhibited by the Pegasus Pipeline.

The Kiefner Paper identified multiple considerations that would cause an operator to determine the need for a "Seam Integrity Assessment Plan" (SIAP) to address the requirements of the new IM regulations for baseline and subsequent assessments of Pre-70 ERW pipe with a method "*capable of assessing seam integrity and of detecting corrosion and deformation anomalies*." The report stated that it is possible to separate ERW pipe segments into three categories (emphasis added):

> *(1) Clear-cut evidence exists that shows that time-dependent deterioration of seam anomalies is occurring. This category will require a special seam-integrity-assessment plan.*
>
> *(2) No direct evidence of ERW seam deterioration exists, but conditions of operation and attributes of the segment suggest that seam deterioration is likely. For pipelines in this category,* ***studies of the attributes, the operations, and the results of other integrity assessments should be made to determine whether or not a special seam-integrity-assessment plan*** *is necessary.*
>
> *(3) On the basis of the attributes of the segment, the operating conditions, the history of the segment, and all evidence generated by other integrity assessments,* ***it is reasonably clear with a high degree of certainty that no time-dependent seam deterioration is occurring****. No special seam-integrity-assessment plan is needed for segments in this category.*

The EMPCo IMP incorporates a similar three category process as outlined in User's Guide Figure 2.1, and the Flow Chart titled Long Seam Susceptibility Criteria for Baseline Assessment, as confirmed in statements made by EMPCo personnel in the CAO hearing on May 3, 2013.

The September 30, 2010 version of the EMPCO IMP Manual specified the categories as;

Category 1 - there was certainty that no time-dependent seam deterioration is occurring (no SIAP needed);

Category 2 - clear cut evidence exists that shows time-dependent deterioration of longitudinal seams is occurring which required development of an SIAP; and

Category 3 - no direct evidence of ERW seam deterioration exists but conditions of operation and attributes of the pipeline segment suggest that deterioration is likely.

Category 3 required additional analyses be performed to determine whether or not an SIAP was necessary. To determine the need to prepare an SIAP for Category 3 ERW pipe segments, the EMPCo User's Guide referred the user to Figure 2.1, a flow chart for determination of long seam failure susceptibility.

The return to normal operations from its idle status required a hydrotest in accordance with the EMPCo IMP and PHMSA regulations. The hydrotesting served as a baseline assessment that was an acceptable method for assessment of pre-70 ERW pipe. The hydrotesting was performed in 2005 to 2006 and resulted in eleven ERW seam failures [See Tab F]. The failures were all analyzed by Hurst Metallurgical Research Laboratory, Inc. (Hurst) and the cause of the failures was determined to be a result of manufacturing defects in the ERW seam, and properties of the base metal in and adjacent to the HAZ. Hurst stated the following in Report No. 51695, which was representative of the failures in the Conway to Foreman segment;

> *In summary, the pipeline specimens failed at less than the design strength of the ERW pipes due to areas of weakness where manufacturing defects were present along the weld seams, and shallow cracks which developed during previous service and/or hydrostatic testing. Additionally, the pipes failed at pressures slightly less than the 1991 test pressures probably due to the hydrostatic tests being conducted at the lower temperatures of 45° F to 46° F in 2006, which apparently reduced the ductility and impact toughness of the weld seams.* [See Tab E]

After the 2005 to 2006 hydrotesting, EMPCo continued to categorize all of the Patoka to Corsicana testable segments of the Pegasus Pipeline as Category 3, and then performed pressure-cycle-fatigue analyses using PipeLife modeling software "*to determine if and when a TFI tool should be run*."

EMPCo relied upon the lack of "clear-cut evidence" without "certainty that no time-dependent seam deterioration is occurring," and determined that the pipeline was not susceptible to seam failures in 2007, 2009 and 2011 in its SFSAs. The analyses used Figure 2.1, Revision Date 3-24-2003, for the four testable segments between Patoka and Corsicana all resulted in "Not Susceptible to Seam Failure." However – the original intent of this flowchart in the Kiefner Paper was to determine ***if*** a Baseline Assessment was necessary. EMPCo had in fact already performed the Baseline Assessments in 2005 – 2006 which identified issues with the ERW seams on various segments of the Pegasus Pipeline.

There was evidence of confusion by EMPCo IM personnel in resolving the apparent inconsistencies in the SFSA process as documented by comments on various flowcharts completed for the Conway to Corsicana Testable Segment of the Pegasus Pipeline in 2007, 2009, and 2011.

PHMSA finds the process in Figure 2.1 inappropriate for a pipeline with the metallurgical characteristics, manufacture, vintage, operating and test failure history such as the Pegasus Pipeline.

EMPCo IM personnel felt that the 2006 Hydrotest "fixed, or addressed" seam failure susceptibility as demonstrated by successful hydrotests and they "expected no more seam failures," as well, since they "achieved successful hydrotest so then defer to fatigue analysis." This belief was further shored up by EMPCo's reliance upon the IMP procedures requiring "clear-cut evidence" before requiring the development of an SIAP. EMPCo nonetheless completed pressure-cycle-fatigue analyses as part of their SFSAs for the Pegasus Pipeline in 2006, 2009 and 2011, as required by the EMPCo IMP where seam deterioration is categorized as "likely."

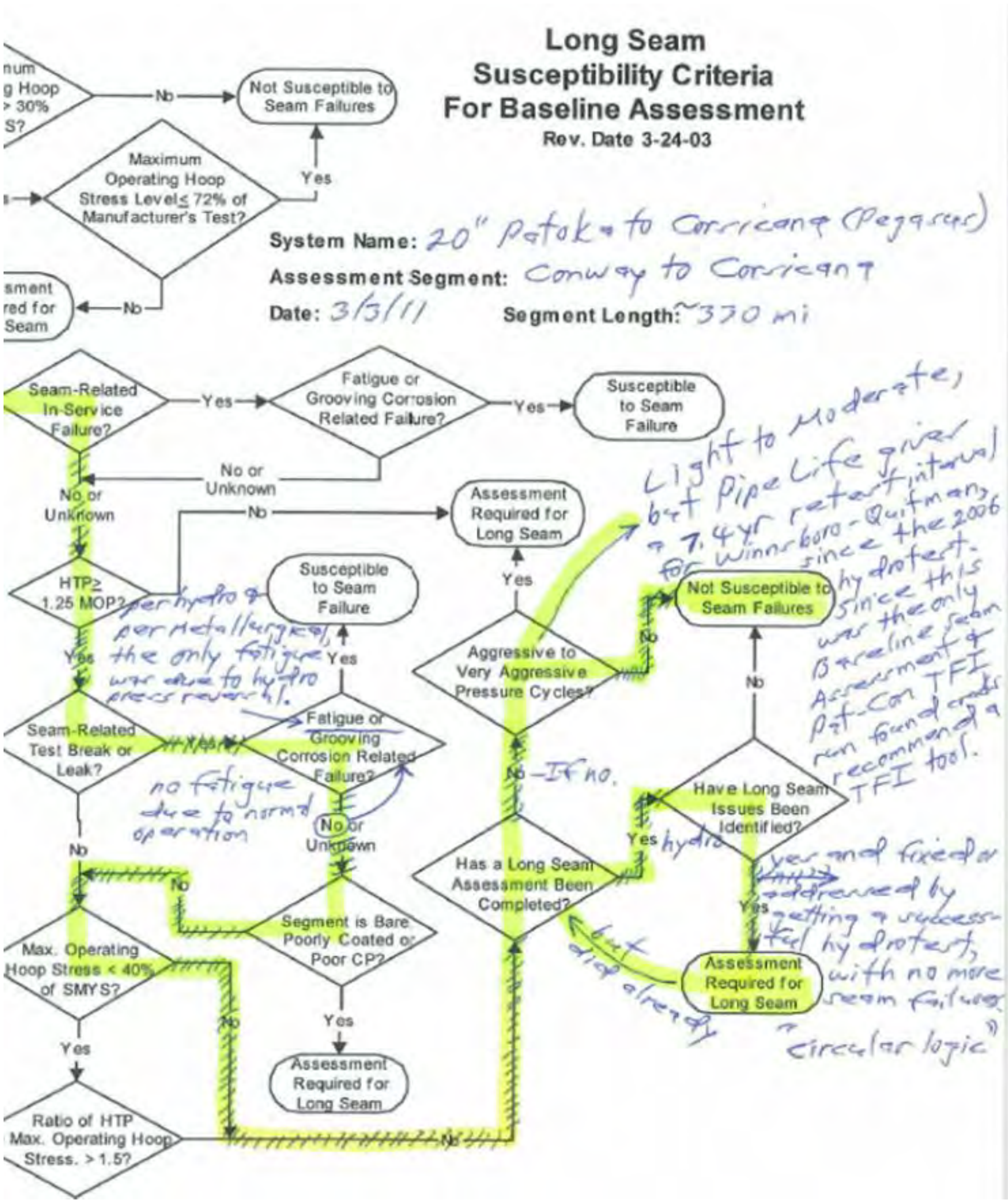
The SFSA analysis process flow chart dealt with only two possible time-dependent threats, fatigue or grooving corrosion, and did not consider other possibilities such as pressure reversals or hydrogen embrittlement that were potential growth mechanisms, as indicated by the results in the Hurst metallurgical reports.

The baseline assessment results were not addressed by the flow chart process. The October 13, 2009 SFSA analysis further modified the process on the flow chart and "assumed no seam assessment was ever completed," and then deferred to the fatigue analysis when in fact this was not part of the flow chart path.

Again, the IM personnel relied on the results of the 2005 to 2006 metallurgical analyses containing no statements of fatigue or grooving corrosion to rule out any mechanisms that could be attributed to the cause of ERW seam degradation over time.

Difficulties in applying the Figure 2.1 process were demonstrated again by the comments from the EMPCo IM personnel in the 2011 SFSA. The process resulted in "circular logic" and the user attempted to modify the process by adding process steps and flow paths to the analysis that were not part of the approved process. No MOC documentation or justification was identified for these process changes, and while logical in nature, the process was circumvented. It would appear that EMPCo circumvented its formal SFSA processes, or as a corollary - processes had not been developed for the appropriate considerations for the management of the ERW seam integrity decisions that were necessary after a baseline assessment had been completed. It would also appear that what on the surface looks like a failure to follow formal procedures, is a failure within the process itself.

The note that distinguishes "operational fatigue" from "hydro pressure reversals" is the only place that these concepts were observed in the EMPCo IM processes. The March 3, 2011 SSF analysis modifications to were documented on the process flow chart as follows.



The 2002 Kiefner Paper identified the following considerations that should be made by a pipeline operator in evaluating seam failure susceptibility as a minimum to be: service-incident history, service-pressure history, test-pressure history and any associated test failures, and the potential for selective seam corrosion.

With respect to in-service failures, Kiefner stated:

> *To be excluded from a seam-integrity-assessment plan, a segment must either have no recorded seam-related service failure, or any seam-related service failure must be entirely explainable as a non-time dependent event (e.g., the failure occurred because the pipeline was accidently overpressured by an amount approaching or exceeding 1.25 times the MOP).*

The EMPCo Pegasus Pipeline had one documented ERW seam related in-service failure documented in a leak and repair report at MP 285.9 in 1984. A repair was made to the pipeline leak and no metallurgical examination report or destructive testing was performed to determine the nature of the seam defect.

With respect to test-pressure history, Kiefner stated:

> *If the investigation of test failures indicate the presence of time-dependent defect growth (i.e., fatigue or selective seam corrosion), a seam-integrity-assessment plan should be developed. The reassessment interval should be based on crack growth rates or corrosion rates that can be inferred from past failures or from similar circumstances on other pipelines. If hook cracks or offset skelp edges are revealed by test breaks but no evidence of fatigue is found, the nature of the pressure cycles on the system should be reviewed to see if fatigue could be a problem. To be excluded from a seam-integrity-assessment plan, a segment should exhibit no test breaks when tested to a pressure level of 1.25 times MOP. Other scenarios that may warrant exclusion could be those in which test breaks occurred but only at test pressure levels well in excess of 1.25 times the MOP and in which large pressure reversals are extremely unlikely.*

The EMPCo Pegasus Pipeline had four ERW seam related test failures documented in the 1991 hydrotest records Three of the 1991 seam failures were in the Conway to Corsicana Testable Segment, and the fourth seam failure was on the Corsicana to Beaumont segment of the pipeline. The 2005 – 2006 hydrotests had 11 ERW seam related test failures which occurred at, below and above the previous 1991 test pressures. EMPCo stated that the "defects included multiple lack of fusion, hook cracks, inclusions, hot tearing, general lower metallurgical properties/strength, or other mill related imperfections." Six of the failures were in the Conway to Corsicana Testable Segment, and five of the test failures were in the Patoka to Conway Testable Segment. The Patoka to Conway test pressures were all higher than the previous 1991 test pressures. The remaining failures were very near or lower than the 1991 test pressures, and this was attributed by EMPCo to be a result of ambient temperature condition differences during testing, not fatigue or growth of flaw sizes.

Fatigue and Selective Seam Corrosion are two examples of time dependent failure mechanisms, but it was not intended by Kiefner to be an all-inclusive list. The use of the EMPCo process flow chart treats these as if they are the only two mechanisms that trigger the pipeline to be determined to be Susceptible to Seam Failure and require the development of an SIAP. The results of the metallurgical testing in 2006 and 2013 for the Conway to Foreman segment clearly indicated that the extension of hook cracks occurred during service life, and while it could not be determined how the "growth" of the hook cracks occurred, it was clear that the defects were not "stable." The 2011 SFSA documented a perceived distinction between "*fatigue due to normal operations*," and stated that "*the only fatigue was due to hydro pressure reversals*." The reliance upon the pressure-cycle-fatigue modeling was apparent in this comment, and caused the operator to disregard other time dependent mechanisms that were well documented in the 2005-2006 test failure metallurgical reports.

EMPCo's process for evaluation of ERW long seam failure susceptibility only focused on the pressure cycling in its supporting fatigue analyses. Further, for conservative purposes of modeling the largest remaining defect surviving the prior hydrotests, higher CVN numbers should have been used to predict crack growth as recommended by KAI. However, the only evidence of EMPCo's awareness of the CVN values role in the remaining life calculations was that "increasing the CVN number decreased the reassessment interval," which was not a desired result. Using a smaller number for the CVN resulted in a smaller remaining defect having survived the hydrotesting, and resulting in more cycles required to grow the defect to failure. Had EMPCo sought outside review or had in-house technical expertise in this area, this aspect of the PipeLife analyses would have most likely been changed to a much higher value (200 was recommended in the recent Battelle work by KAI) than the value of 7 used for CVN by EMPCo.

With respect to selective-seam-corrosion, Kiefner states that a *"pipeline with a known selective-seam-corrosion problem is clearly a candidate for a seam-integrity assessment."*

No evidence of selective seam corrosion (grooving corrosion) was indicated in any of the test failures or the in-service leak on the Pegasus Pipeline. However, the TIARA questionnaires in both the 2006 and 20011 analyses had answers of "yes" to the inquiry of "*Has external corrosion-related cracking (ie., selective seam corrosion) ever been found near this segment*?" The 2010 NDT Linalog inspection of the Conway to Corsicana Testable Segment resulted in 311 axial or circumferential grooves.

The last revision to the Figure 2.1 flow chart used in the SFSAs appears to have been made in 2003, when the Pegasus Pipeline was idle and purged with nitrogen. However, the Baker Report, April 2004, contained the following comments of the flow chart that was the basis for EMPCo's Figure 2.1:

> *The means of determining whether or not the seam of a particular pipeline is susceptible to failure are illustrated in Figure 4.1. Some of this material was presented and discussed in Dealing with Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe with Respect to HCA-Related Integrity Assessments (Kiefner, 2002), but the process has evolved over time. Figure 4.1 represents a decision tree that allows one, by supplying appropriate data on a given segment, to determine if a seam integrity assessment is required based on the federal pipeline integrity management regulations. This decision tree has been expanded and modified to form the basis for the guidelines recommended in Section 9.*

The revisions to the 2002 process flow chart covered in Section 9 of the Baker Report were not apparent in any of the SFSAs performed by EMPCO on the Pegasus Pipeline. The Baker Report [See Tabs H and I] included recommendations for engineering analyses, and additional decision processes and considerations that updated the previous considerations. Based upon the updated flow charts in Section 9 that should have been incorporated into EMPCo's Figure 2.1; and considering the history of the Pegasus Pipeline, the recommendations of Section 9 of the Baker report were to complete a Fitness for Service Analysis in accordance with API RP579 [See Tab I], or similar technique. No such study has been provided to PHMSA by EMPCo.

EMPCo's treatment of the Pegasus Pipeline as not susceptible to seam failure, in its entirety, was inconsistent with PHMSA's expectations, and was in contradiction to information known to EMPCo, in light of known expert analyses and guidance. In light of the industry knowledge and experience available to the operator, known pre-50s Youngstown LF-ERW pipe manufacturing concerns, and the Pegasus test-failure history and resultant information contained in the metallurgical investigation reports, EMPCo should have considered much of the pipe in the Patoka to Corsicana segment of the Pegasus Pipeline as Susceptible to Seam Failure.

-- end--

Material Properties, the Role of Toughness, and Fatigue Analyses

Tab E is a discussion about material properties that provide some basic concepts to assist the reader with these topics as discussed in Appendix E and its associated Tabs.

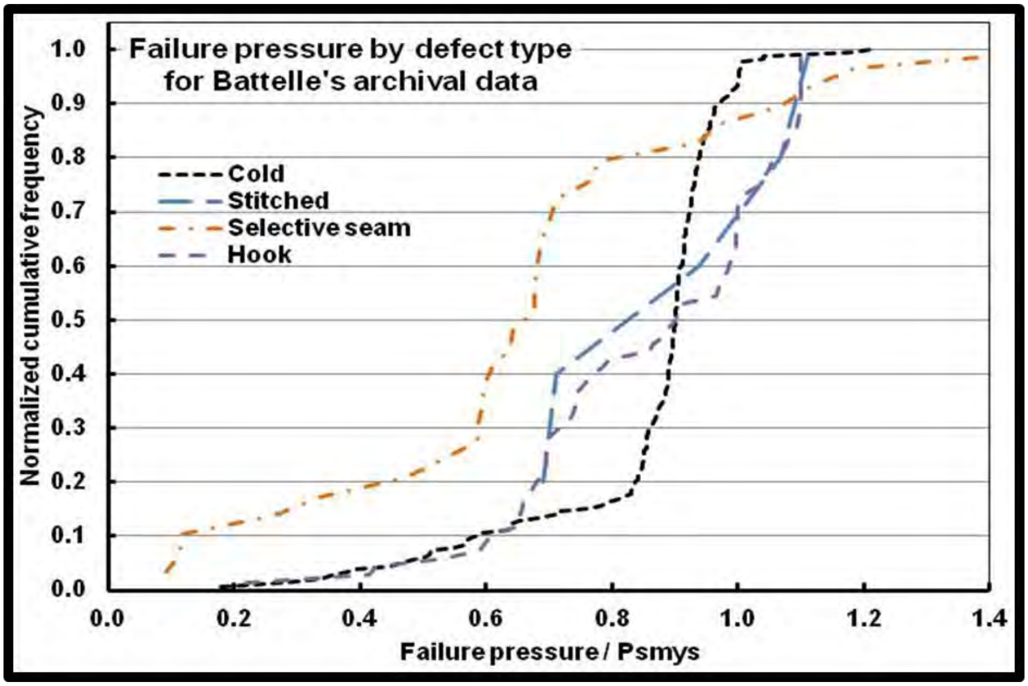
A basic understanding of material properties, fracture mechanics, toughness and associated testing is necessary for the application of models used in fatigue analyses, and the understanding of failure mechanisms that are typical of pre-70 ERW pipe. This subject matter is explained in detail in the Baker Report (Tab A) and Tab H is a reprint of the portions of that report. The Baker Report explains that there are rough correlations between CVN impact toughness upper shelf absorbed energy, which measures resistance to fracture propagation, and the static fracture initiation toughness. An understanding of the relationship between the fracture initiation and fracture propagation properties in the temperature domain is also necessary to successfully use methods that aim to evaluate fitness for service or remaining life of a pipeline asset.

As noted in the Baker Report:

> *It is safe to say that all low-frequency and DC-welded materials possess bondline regions that are prone to low toughness and brittle-fracture behavior. This is because there was no way to prevent grain coarsening in the heat-affected zones. The enlarged grains invariably made the weld zones less tough and more prone to brittle fracture than the parent material. To some extent, this tendency was reduced with the use of high-frequency welding because a smaller volume of material is heated than in the case of a low-frequency or DC process. In addition, by the 1970s most manufacturers were using microalloyed, thermomechanically treated skelp. These steps prevented or eliminated grain coarsening and thereby resulted in bondline regions of ERW pipe that are as tough as the parent metal.*
>
> *These [hook] cracks can be up to 50 percent of the wall thickness in depth and up to several inches in length. They are in effect a pipe defect, not a weld defect, and their behavior is governed more by parent pipe toughness than bondline toughness. They tend to be much larger than bondline defects in the older materials because the low toughness of the bondline regions assures that no large defects can exist after a hydrostatic test to a reasonably high-pressure level.*

The current PHMSA sponsored Battelle research project has ERW failure data and determined that what constitutes a “reasonably high-pressure” level is roughly 90% SMYS, or greater. If lower stress level pressure test limits are chosen by the operator, then a test factor of 1.39 should be used in lieu of 1.25 to ensure an adequate level of safety [See Tab A Battelle Study for further information and links to study reports]. For example, a test pressure at 80% SMYS might be 1300 psig, and that pressure, divided by the test factor of 1.39 would allow the pipeline to operate at an MOP of 1300/1.39 or 935 psig.

This recommendation is based upon the review of industry failure data for nearly 600 ERW seam failures in the Battelle, KAI, and DNV archives. The cumulative frequency was determined as a function of failure pressure for each of the four categories of failures presented in the following chart. High test pressures are required to clear out a significant fraction of the features. A higher test pressure assures a longer interval before a retest is necessary.



The resinspection interval typically relies upon calculation of fatigue crack growth models that rely upon the "Paris Law" approach provided the user is able to supply the relevant data for the pipe and its material properties. Toughness and flow stress can be addressed in the absence of actual data by using conservative assumptions based on industry fitness-for-service standards or recommended in the studies referenced herein.

The Baker Report defines "fatigue" as the process of initiation of a crack, propagation of the crack (i.e., enlargement of the crack), and final fracture of the crack as a result of elapsed cycles of applied stress in service. These three processes are distinct phases and although they occur sequentially, are governed by separate considerations.

The material toughness, as represented by CVN values, is dependent upon temperature. This relationship is discussed in more detail in Section 7 of the Baker Report [See Tab H]. The development of S-graph Curves through CVN testing at varying temperatures allows the transition temperature to be determined, and determine the Upper Shelf Limit. Figure 7.6 [See Tab H] from the Baker Study illustrates an S-Curve graph developed from CVN test results. The curve then allows the determination of the SATT which is for all practical purposes the point at which full upper shelf (ductile) behavior can be expected.

CVN testing was performed as part of the metallurgical failure analysis testing of the 2006 hydrotest test failures and the 2013 in-service failure at MP 314.77 by Hurst Metallurgical Research Laboratory, Inc. (Hurst). The impact testing was completed at various temperatures ranging from +35° F to +95° F in the 2006 hydrostatic test failure analyses, and from -32° F to +95° F for the 2013 in-service failure analysis. The 2006 failure reports prepared by Hurst included the results of the CVN tests at the varying temperatures and the conclusions included statements noting the test temperatures for the 1991 hydrostatic testing were in the range of 85 to 95°F while the 2006 testing was conducted at 46 to 47°F, or lower, depending upon the specific failure location.

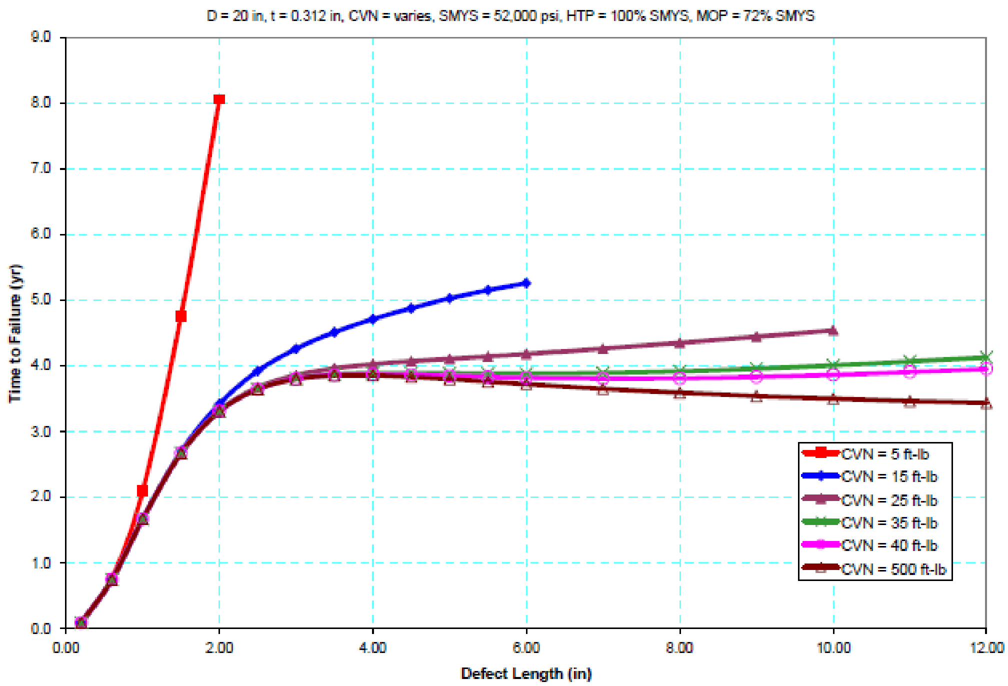
The 2013 Hurst Report stated that the CVN tests were intended to be plotted to develop an S-graph curve to determine the brittle to ductile transition line. However, the impact test results in the failure areas were roughly the same regardless of the test temperature. The CVN impact test specimens notched in the ERW seam, whether at the fusion line or in the HAZ, all failed in an essentially brittle manner. This indicates that the ductile to brittle transition temperature was above 95° F. Therefore, it would be reasonable to conclude that many of the failures were not in fact a function of the lower ambient temperatures during testing in 2006. Further, the temperatures at which both hydrotests occurred were within the design parameters for the normal pipeline operations of the Pegasus System.

The 2005-2006 long seam test failures all occurred in the seam and near seam heat affected zone (HAZ), not the body of the pipe in both the 2006 hydrotest failures and the 2013 in-service test failure. The results of the impact tests across the ERW bondline all exhibited low CVN values with little to no variation due to temperature. The 2006 Conway to Foreman test failures resulted in CVN values that varied only slightly with respect to temperature, in most cases. These values are presented in tabular form as follows.

2006 Hydrotest Failure Milepost	CVN (ft-lbs) ERW Seam			CVN (ft-lbs) Base Metal		
	+ 35° F	+ 65° F	+ 95° F	+ 35° F	+ 65° F	+ 95° F
MP 298.1	3	5	4	7	12	22
MP 294.1	n/a – full seam split			11	11	11
MP 243.8	3	3	3	4	8	13
MP 238.9	2	2	4	5	6	12
MP 190.3	n/a – full seam split			5	9	10
MP 188.2	n/a – full seam split			9	10	11

While it is clear that there is a relationship between toughness and CVN values, there is not enough evidence to conclude that the 2006 test failures were a result of reduced toughness at lower temperatures as demonstrated by the test results on the Conway to Foreman segment of the pipeline. It was disappointing to note that EMPCo in both the 2006 failure reports and its 2012 Root Cause Failure Analysis for the Torbert, LA pipeline failure went to great lengths to attribute the failures to any possible cause other than the growth that was occurring in the manufacturing flaws in both pipelines, as demonstrated by failures at lower pressures than the pipeline previously experienced. It would appear that there are underlying, non-integrity related issues that would motivate an operator to actually seek alternative explanations for the failure mechanisms resulting in incorrect conclusions in incident investigations and failure analyses. Regardless of whether it is a lack of subject matter knowledge, a concern over asset-devaluation, or potential compliance or litigation concerns, the ultimate failure of the operator’s actions is the failure to learn and apply the appropriate corrective actions.

The Baker Study Report OPS TT06 provides a comparison of time to failure compared to defect size for different CVN values as modeled using in the next graph. The Study Report happened to model a similar pipe to the Pegasus Pipeline in that it was 20” diameter, .312-inch wall thickness, but with a slightly higher SMYS of 52,000 psi. The metallurgical testing of the Pegasus Pipeline did reveal that while it had a minimum specified yield strength of 42,000 psi, it tested much higher, and closer to the values represented in this graph.



The graph shows that for low CVN values representing low toughness, only very small defects can be tolerated. In fact, it is interesting to note that these defect sizes are roughly the same size as the published detection threshold for most TFI tools which typically have a state that the threshold level of detection is 2 inches in length and 50% depth +/- a tolerance.

The CVN value is an important factor for use in modeling related to surviving defects after hydrotesting or in-line inspection using the same model to predict the time to failure for the largest remaining defect after the assessment to grow to failure or "critical size." However, inputting a low CVN into crack growth models that use algorithms modeling the relationship of the pressure cycles on a pipeline to the material properties and known defect sizes, use of a lower CVN in the process has the effect of starting the analysis with the assumption of a much smaller flaw size, requiring more pressure cycles (more time) for the flaw to reach critical size.

Without presenting the entire modeling concepts herein when other technical references are provided in Tab A that cover the concepts, suffice it to say that the model assumptions are critical to valid analyses, and as previously stated, a basic understanding of CVN relationships to fracture mechanics is needed for application of the results in the integrity decisions that use such models.

Growth of seam defects due to pressure-cycle-induced fatigue is a function of four factors; pressure cycles, the presence of a family of initial flaws, environmental conditions, and the toughness of the pipe. While all evidence points to fairly light to moderate pressure cycles on the Pegasus Pipeline, there were clearly initial flaws present, low toughness and the potential for environmental effects.

The following excerpts from the Baker study form the basis for a general understanding about the processes of the pressure-cycle-fatigue growth analyses that EMPCo was performing, with one exception. During the May 3, 2013 CAO hearing, EMPCo stated that EMPCo incorporated this process into their SFSA, and they did not consider the Pegasus Pipeline susceptible to seam failure because there had been no in-service failures. The study however treated in-service and hydrotest failures in the same manner, and as described hereafter would have considered the Pegasus Pipeline as susceptible to seam failure.

Baker Report Data Considerations:

4.3.2 Failure History
If a seam-related in-service or hydrostatic test failure has occurred on the segment, the segment is considered susceptible, and if time-dependent growth is shown to be a factor in the occurrence of the failure, reassessment becomes necessary.

Although a single failure does not prove the existence of other similar defects, it is reasonable to assume that defects do exist in the seam. Whether or not these hypothetical defects are susceptible to time-dependent growth is not certain. One must assume that with seams containing populations of defects residing in a pipeline subjected to significant numbers of large pressure cycles, the seams could be susceptible to fatigue failures at some time in the future. Similarly, from the standpoint of selective seam corrosion, if the standard anti-corrosion measures of coating and cathodic protection are absent or deficient, it is assumed that a seam-integrity-assessment program will be needed to assure the absence of failures from selective seam corrosion."

"4.3.3 Implications of Toughness
The toughness of the pipe material determines the sizes of cracks that can survive a given level of hydrostatic test pressure and the sizes of cracks that will cause the pipe to fail at the MOP[5].

[[5] A failure pressure level for a given size defect is calculated via the "log-secant" equation developed by W. A. Maxey (Kiefner, 1973) the toughness of the material in terms of ft-lb of Charpy energy and the dimensions (length and depth) are entered to calculate the failure pressure. Conversely, for a fixed level of pressure (such as a hydrostatic test), a range of critical flaw sizes (lengths and depths) can be calculated.]

The "starting" sizes established by the test pressure and the toughness have a very significant effect on fatigue life whereas the final crack sizes established by the MOP and the toughness do not. This is the result of the fact that the crack growth per cycle of pressure is a function of both pressure cycle size and crack size. A small starting size, therefore, results in a slowly growing crack and a large starting size results in a more rapidly growing crack. By the same rationale, when the crack is near failure, the steps of growth per cycle become so large that the level of maximum pressure is not that important. That is, the failure pressure will be reached within a few cycles even if the actual maximum level is well below the MOP. In most cases analyzed to date, a toughness of 25 ft-lb was assumed. This value is considered representative of the base material (not the bondline) of ERW pipe manufactured prior to about 1970. A value as high as 40 ft-lb would be at the technologically achievable limit for the time, and it would not result in a significantly shorter predicted fatigue life because 25 ft-lb is close to the level needed to assure the largest possible starting crack size for this size of pipe.

4.3.3.1 Fatigue Crack Growth
In the model used by a number of operators to determine susceptibility to seam failure, a "Paris-law" approach (Paris, unknown) is used to predict the rate of fatigue crack growth. This type of model involves the assumption that the natural logarithm of the rate of crack growth is proportional to the natural logarithm of the range of stress-intensity factor at the crack front during each cycle of pressure.

4.3.3.2 Pressure Cycles and Points for Analysis
Either a hydrostatic test or an in-line inspection can be used to establish starting defect sizes for calculation of times to failure. Potential defects that could have barely survived the last hydrostatic test or the largest defect that can escape detection by the last-used in-line inspection tool are postulated to grow for a period of time as the pipeline as the pipeline is subjected to the pressure cycles and/or a specific selective seam corrosion rate. It should be noted that the predicted number of years until failure is based on the assumption that defects of a given size exists. If no such defects exist, the time to failure will be longer.

EMPCo uses the KAI software PipeLife, for predicting times to failure for ERW seam defects that grow by pressure-cycle-induced fatigue. The model requires an analysis of the pressure cycling to be performed to determine the aggressiveness of the operational pressure cycles. The results are presented in a table of values for different levels of pressure cycling severity ranging from light to very-aggressive. EMPCo purchased the software from KAI and performed the analyses using EMPCo personnel. KAI recommends using one year of operational pressure data to ensure any seasonal operating variations are captured. Further, KAI suggests that pressure cycle data should be collected on 2 to 5 minute intervals to ensure all pressure cycles are captured in the analysis. EMPCo used one or two months of pressure cycle data taken at one minute intervals. KAI also recommends selecting various locations along the pipeline to determine the worst case on segments because they are not always at the pump station discharge. EMPCo ran only the Pump Station Discharge locations in their analyses.

EMPCo performed pressure-cycle-fatigue analyses PipeLife to predict the time to failures for the Patoka to Corsicana testable segments again in 2009, and 2011 as a basis for "*if and when a TFI tool inspection should be performed*." Each time, the pressure cycles were assumed to be light to moderate, and there were no operating conditions where pressure cycles were determined to be aggressive or very aggressive by the EMPCo personnel performing the analyses.

As part of the 2011 Battelle Study, KAI prepared a report under SubTask 2.5 titled "*Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue*," (KAI Report) dated January 28, 2013. The process of scheduling retesting or remediation via fatigue-crack-growth analysis is described in the KAI Report as involving "*establishing the initial sizes of defects, applying representative operational pressure cycles to cause the defects to grow, and determining the number of pressure cycles required to cause the defects to grow, and determining the number of pressure cycles required to cause the defects to attain (final) sizes that will cause a failure at the maximum operating pressure (MOP) of the pipeline…A factor of safety is then applied to the time so that a response is made well before any growing defect can reach a size that would cause a failure at MOP*."
There are other models for analyzing pipeline fatigue, none of which were utilized by EMPCo in their analyses. There was no evidence that EMPCo IM employees sought other models to characterize the behavior of the Pegasus Pipeline, even after the 2012 Torbert, LA event where EMPCo experienced a similar failure on another

LF-ERW pipeline system that had failed well in advance of the predicted re-inspection interval using the same model and IM processes.

EMPCo has focused on the Mayflower and Torbert failures as being “unique,” “isolated” and characterized the pipe characteristics as “atypical” when in fact the properties demonstrated by the four EMPCo failures are typical of pre-70 ERW pipe, as demonstrated in several collections of ERW failure data, the most recent published by Battelle as part of the PHMSA sponsored ERW comprehensive study, and all of the results of the test and in-service failures for which EMPCo had metallurgical analyses performed. EMPCo failed to identify these key issues and revise its IM processes to incorporate lessons learned from its failures as required by OIMs, and federal pipeline safety regulations.

In July 2012, EMPCo ran a fatigue analysis for the entire Pegasus System using 30 days of operating data from May 1 through May 31, 2012. The predicted maximum retest intervals from the 2005-2006 hydrotest were significantly different for several line segments from the earlier fatigue analyses, including intervals that resulted in dates that were already in the past. The operating conditions used in the 2012 fatigue analyses reflected post 2009 expansion operating pressure cycles. The IM personnel concluded that EMPCo “*can’t use, makes it past due, and didn’t operate this way 2006 -2009*” for all line segments that were past due. The Conway Discharge Pipe Analysis Results as modeled in the July 2012 fatigue analysis resulted in the graph shown in Figure Y. Using the reported defect size of 13.25-inches and a d/t ratio of 0.44 results in a predicted failure rupture pressure of about 650 psig. The actual failure pressure was calculated to be 708 psig at the failure location. The difference in failure pressures can be explained by the actual SMYS being much higher, and the measured CVN value being lower than modeled in the analysis.

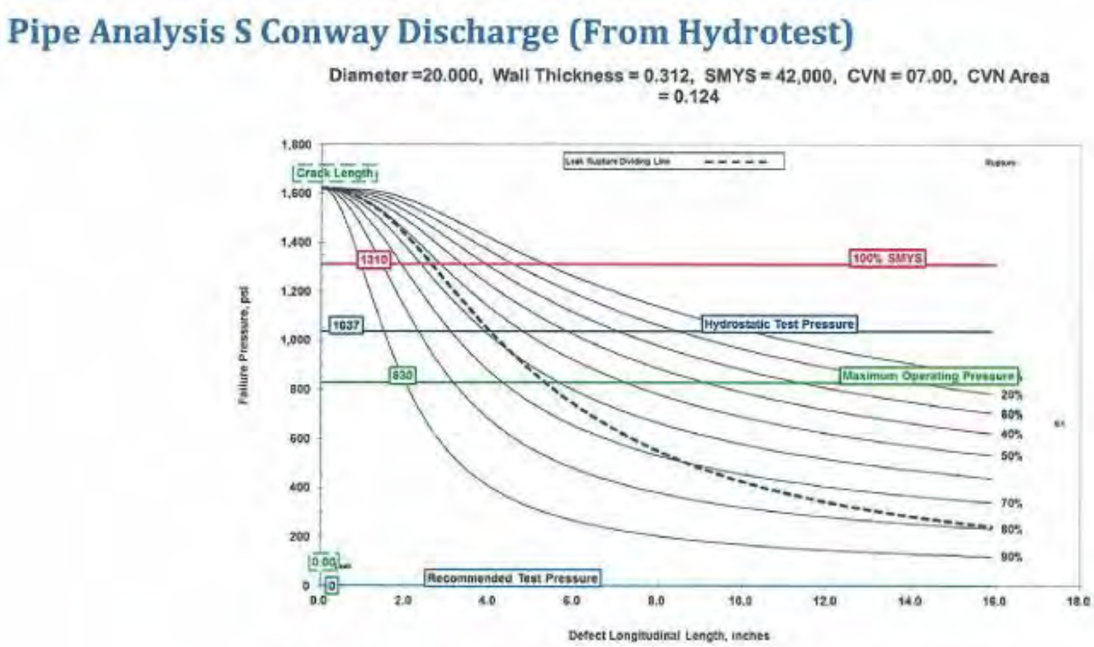


Figure Y – 2012 Pipe Analysis – Conway Discharge Results

Evidence was found where EMPCo re-ran the underlying fatigue analyses used to support the SSF flow chart process when the desired re-inspection interval results were not obtained, and re-ran TIARA analyses to see what affect running the TFI tool would have on the risk scores or if the process resulted in unacceptable risk scores. No evidence was found that indicated EMPCo ever questioned the validity of their conclusions about long seam failure susceptibility, and in fact, during the Corrective Action Order Hearing of May 3, 2013, in Houston, TX, EMPCo Integrity Management personnel emphatically held their position that the Pegasus Pipeline was not considered susceptible to seam failure.

The method of re-assessment of pre-70 ERW pipe can be either hydrostatic testing or in-line inspection with a tool capable of detecting the size and type of defect that is present in the pipe or pipe seam. Regardless of the results from the engineering analyses, the maximum interval for re-assessment is five (5) years, not to exceed 68 months from the prior assessment, *for all threats*, in accordance with 49 CFR 195.4452(j)(3).

The decision regarding the selection of the type of re-assessment method should have considered the failures experienced in the previous assessments. Section 3, and again in Section 8 of the Baker Report, discusses the importance of toughness on the effectiveness of hydrostatic testing and ILI. The report concludes that for ERW pipe made of materials with a reasonable level of toughness (around 25 ft-lb, as expressed in terms of Charpy energy), "*it appears the use of proven ILI techniques will most likely provide a higher degree of integrity assurance than hydrostatic testing (at least to practical limits imposed by the quality of older line-pipe materials) for the most important integrity threats (i.e., corrosion-caused metal loss and crack propagation phenomena in materials with reasonable toughness levels)…In those cases where a low or very low-toughness material is involved [well below 25 ft-lb], however, the reverse is true. In those cases, it appears with today's [2004] tool-inspection thresholds that hydrostatic testing would give superior assurance."* These results were further supported by the findings of the NTSB Investigation of the 2007 Dixie Pipeline failure.

The material toughness is a significant factor in the SIAP development, and is a critical factor in the selection of the assessment method for LF ERW seam pipe materials. Based upon the information from the 1991 and 2006 hydrotest failures and their associated metallurgical results, EMPCo should have considered portions of the Pegasus Pipeline, and specifically the Conway to Foreman Testable Segment as susceptible to long seam failure, and used hydrostatic testing, or a combination of hydrostatic testing and in-line inspection with TFI, UT or EMAT as the proper assessment method with a maximum five-year assessment interval, not exceeding 68 months. Any variation from these methods or timing would have required approval by EMPCo, in accordance with their IMP, and PHMSA under the requirements of 49 CFR 195.452(j)(4).

--end--

EMPCo 2005-2006 Pegasus Hydrotesting

Tab F is a summary discussion of the 2005-2006 hydrotesting and test failures experienced on the Pegasus Pipeline Patoka to Corsicana portion of the system.

The Pegasus Pipeline from Corsicana to Patoka was idle from 2002 to 2005 during which time it was purged with nitrogen, and no product was in the pipeline. Prior to its return to service, during the "Reversal" project phase, concern was expressed among EMPCo personnel about *"fatiguing the seams"* during hydrotesting, and this concern, along with project optimization ultimately resulted in an internal challenge as to the necessity of the testing. It was determined that both EMPCo IM procedures required testing of an idle line that had been out of service for more than 12 months as part of the reactivation procedures. Additionally, it was communicated internally that PHMSA FAQ 2.3 addressed the requirements of the IMP regulations to idle pipe, requiring all deferred repairs and integrity assessments be performed prior to return to service. The most recent assessment prior to idling of the line was a 1991 and three 2001 in-line inspections on the four Testable Segments. All of the repairs identified by the four in-line inspections had not yet been completed, and were subsequently completed, prior to the 2005-2006 hydrotesting of the line. EMPCo determined that it was required by both the EMPCo IMP and PHMSA IM regulations that the Pegasus Pipeline be hydrotested/assessed prior to its return of service.

The hydrotesting of the Patoka to Corsicana Segment began on the north end of the pipeline system in November 2005. The original test plan was designed by EMPCo, Englobal/IDS Engineering and Mustang Engineering. The test pressures were designed to achieve a desired MOP of about 805 psig at high points on the line achieving a low point maximum MOP of 943 psig, (based upon a maximum pressure allowed by federal regulation of 0.72 times SMYS). The design test target ranges were then set at roughly 1179 psig (1.25 times 943 psig minimum at low points) to 1199 psig to address the elevation differences in the Hydrostatic Test Plan.

To account for differences caused by hydrostatic head, test segments must be separated when pipeline elevation charges are significant, as illustrated in Figure X. The same test segments used in the 1991 testing were used for the test segmentation in the 2005-2006 testing. The 2005 design basis MOP target was 805 psig, and was established with the intention of testing at high enough pressures to contemplate the maximum future expansion of the system without having to perform additional testing.

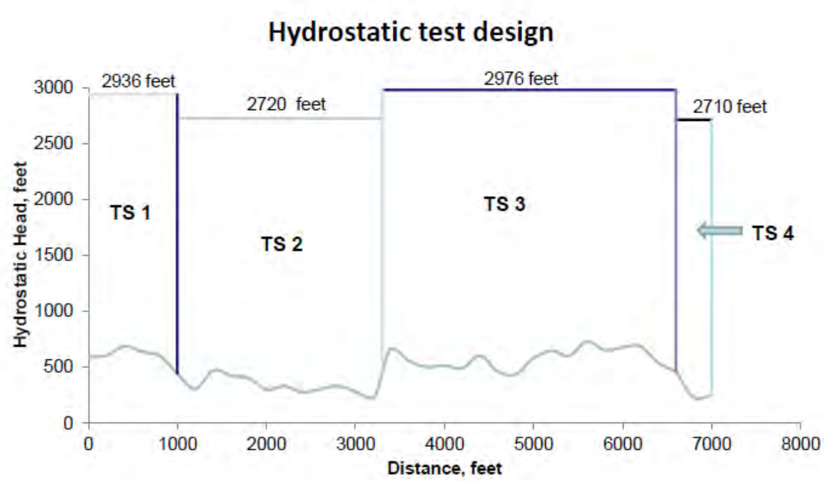
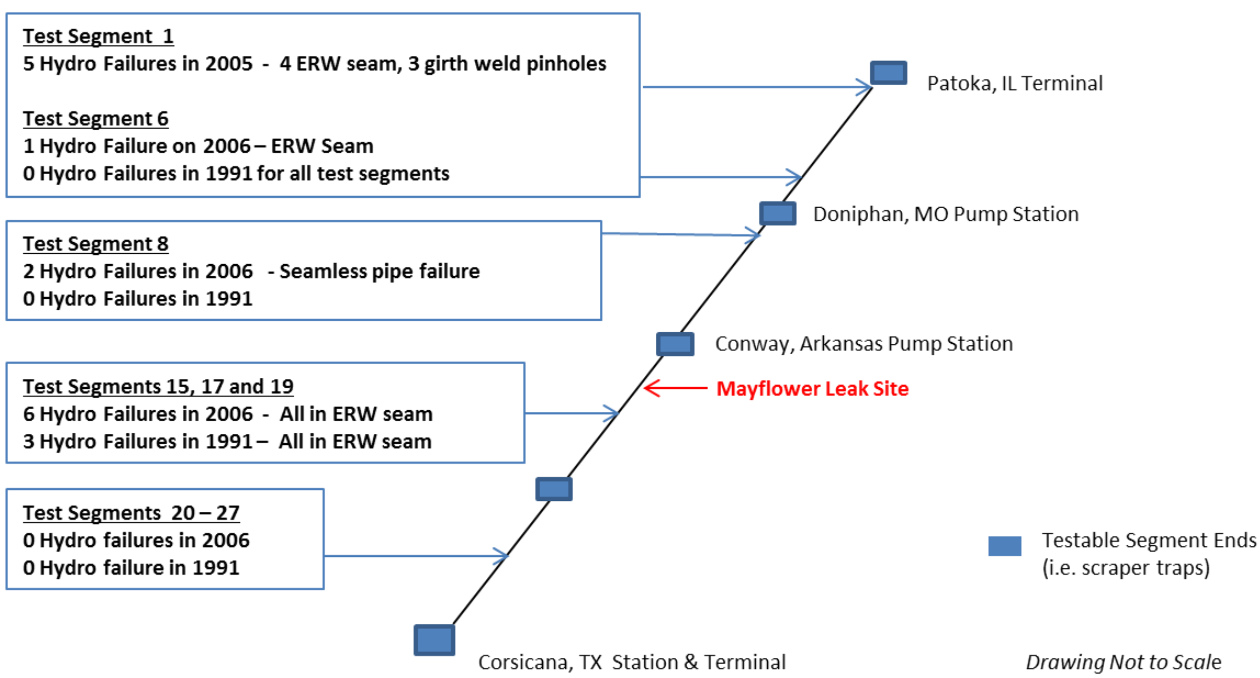


Figure X – Typical Hydrostatic Design Test Segments

The 2005-2006 planned test pressures were roughly 150 to 200 psig higher than the 1991 hydrotests which were performed in response to new regulations added to 49 CFR 195 for testing of pipelines constructed prior to February 1970.

Patoka to Corsicana Hydrotest Failure Locations



During the 2005 to 2006 hydrotesting of the Patoka to Corsicana pipe, six (6) of the 27 tests experienced a total of twelve (12) pipe joint ruptures. There were also three pinhole leaks in two test sections that were repaired in place and did not require replacement of pipe. EMPCo prepared a summary of learnings from the 2005-2006 hydrotest failures and metallurgical reports in a Memo to File prepared by IM personnel. The 'Memo to File' summarized the cause of the failures for the eleven (11) failures in the ERW seam as having "*failed in the ERW seam vs. body due to the presence of multiple mill defects in the seam that made its design strength weaker than that of the body of the pipe. Failures were below, at, or above 1991 test pressures…The defects included multiple lack of fusion, hook cracks, inclusions, hot tearing, generally low metallurgical mechanical properties/strength, or other mill related imperfections*." The memo went on to conclude that "*CVN toughness testing, and researching the 1991 hydrotest revealed lower test temperature was likely a contributing factor in why they failed at less pressure than what they were tested to in 1991. This is as opposed to other time dependent defects like preferential corrosion or pressure cycling fatigue of the seam.*" However, for the failures where the 2005-2006 test pressures were higher than the 1991 test pressures, EMPCo concluded that "*We know from our CVN toughness testing that test temperature had to also be a factor but to which extent higher pressures or lower temperatures played a role in the failures we don't know.*"

The first test section was Test Section 1 from Patoka, IL MP 604.98 to 647.73. Test Section 1 was tested, and five test failures occurred before a successful hydrotest was completed. Four of the failures resulted from ERW long seam failures and the fifth test failure was due to pinhole leaks in girth welds. The fifth hydrotest was successfully completed after the pinhole leaks were repaired in place, but the line segment was ultimately tested at a lower pressure than planned in the design basis. The following table summarizes the test results for Test Segment 1.

Test Plan – Test pressure values at test site: 1154 psig min, 1174 psig max, MP 605, elevation 520 ft

Test Date	Failure Location	Failure Pressure at Failure Site (Adj. for elevation)	1991 Test Pressure	% SMYS Basis - X42	Test Result
11/05/05	MP 638.5	1126 psig	975 psig	86%	Retest
11/06/05	MP 629.3	1204 psig	1004 psig	92%	Retest
11/11/05	MP 637.3	1149 psig	982 psig	88%	Retest
11/20/05	MP 624.7	1131 psig	995 psig	86%	Retest
Test Date	Test Site	Min. Test Pressure	--	% SMYS	Test Result
11/23/05	MP 605	1005/906 psig	--	77%	Successful (after repair of girth weld pinhole leaks)

The initial test plan would have established an MOP of 923 psig at the test site. However, as a result of the test failures and project schedule concerns, EMPCo chose to lower the test pressures to achieve a successful test without further test failures, and as a result, accepted a lower than desired MOP of 805 psig at the test site. The MOP of the pipeline was subsequently established in accordance with the federal pipeline safety regulations in 49 CFR 195 by taking the test pressure and dividing it by the test factor of 1.25. The failure analyses in Test Section 1 concluded that the pipe failed as a result of original manufacturing defects, and being subjected to pressures that it had not ever seen before. The EMPCo hydrotest reports noted that no signs of fatigue, selective corrosion or other time dependent defects were observed.

The next hydrostatic test failure occurred in Test Section 6, MP 496.30 to MP 529.84. This test failure occurred at MP 528.2 on December 2, 2005, at a test pressure of 1031 psig at the failure site. The same conclusion for the failure was reached as in the first four test failures. The cause was attributed to original manufacturing defects, and being tested to a higher pressure than the pipe had ever seen before with no observations of time dependent defects observed. The previous test pressure in 1991 was reported to be 956 psig.

The next hydrostatic test failure occurred in Test Section 8, MP 437.74 to MP 472.57 in a segment of seamless pipe at MP 441.4 on December 19, 2005, at a test pressure of 1096 psig; after having survived a previous hydrostatic test in 1991 at 982 psig. The metallurgical evaluation determined that the pipe failed at a location of severe damage on the surface of the pipe in the form of gouges.

The hydrostatic test pressures for Test Sections 1 through 8 had been planned at higher levels than the previous 1991 levels. However, the remaining test sections from Test Section 9 through 27 were tested at roughly the same pressures as in 1991. It was unclear if this was a conscious choice that considered the previous hydrostatic test failures experienced in 1991, a result of the experience from the first 8 test sections, or some other factor.

The next hydrostatic test failures occurred in Test Sections 15, MP 283.64 to 299.41; 17, MP 238.25 to 257.5, and 19, MP 182.99 to MP 217.06 with each section having two test failures from ERW seam failures as summarized in the following table.

2006 Conway to Foreman Segment Hydrotest Failures

Test Date	Failure Location	2006 Failure Pressure at Failure Site (Adj. for elevation)	X42 % SMYS versus Actual Yield and w.t.	1991 Test Pressure
1/29/06	MP 298.1	1169 psig – cold weld, shallow cracks	89% / 74.6% 51,250 psi, .306”	1177 psig
1/31/06	MP 294.1	1092 psig – cold weld, upturned fibers	83% / 63.9% 55,500 psi, .308”	1116 psig
2/7/06	MP 238.9	1066 psig – crack 7/8”wide by 5/32” deep through bondline, inadequate bonding of skelp edge	81% / 72.2% 51,300 psi, .288”	1059 psig
2/17/06	MP 243.8	1078 psig – upturned grains, inclusions, fifteen (15) hook cracks in the fracture zone, growth indications at hook cracks	82% / 70.7% 51,000 psi, .299”	1072 psig
2/22/06	MP 190.3	1122 psig – hook cracks, visual indication of growth	86% / 63.3% 58,500 psi, .303”	2/22/06
2/13/06	MP 188.2	1088 psig – stringer type manganese sulfide inclusions parallel to bondline, grain orientation	83% / 60.2% 57,000 psi, .317”	1116 psig

While the metallurgical reports remained silent on the subject of fatigue, the hydrotest Review Reports by EMPCo stated that “*No fatigue, selective corrosion, or other time dependent defects were observed*.” Also, in these test reports, the lower test pressure failures in 2006, as compared to 1991 test pressures were attributed to the lower test water temperatures in 2006 compared to the 1991 testing temperatures.

Was the conclusion that the 2006 test failures which occurred at lower test pressures than in 1991 attributable to lower temperatures during testing reasonable and conclusive enough to rule out fatigue or growth of the hook cracks in the process flow chart? The metallurgical laboratory was unable to provide clear cut evidence that fatigue was a factor in the failures because of the condition of the ruptured surface upon arrival in the laboratory. The oxidation on the fracture surfaces prevented this evaluation. Further, the Charpy v-notch (CVN) test result values were very low for the pipe samples tested, and the fractures were brittle in nature, and did not demonstrate ductile behavior typically evidenced in a fatigue related failure. However, all of the hydrotest failure reports by Hurst and the other various metallurgical labs used to prepare failure reports in Tab J indicated that the chemical and material properties for all pipe tested were representative of the vintage of the pipe. For low-toughness seams, the only flaws that would be expected to grow by fatigue are hook cracks which are off the bondline. If the seam had low toughness a fracture mechanics analysis would indicate that from a practical standpoint only very small flaws could be tolerated [See Tab H].

While clear-cut evidence of fatigue was not identified, there was enough likelihood that seam degradation was occurring over time as indicated by pressure test failures at lower pressures than previously tested, and at significantly lower stress levels than 90% of the pipe’s specified minimum yield strength. Based upon the Kiefner Paper position that to “*be excluded from a seam-integrity-assessment plan, a segment should exhibit no test* *breaks when tested to a pressure level of 1.25 times MOP. Other scenarios that may warrant exclusion could be those in which test breaks occurred but only at test pressure levels well in excess of 1.25 times the MOP and in which large pressure reversals are extremely unlikely."* The test failures in the Conway to Foreman segment of the pipeline were not well in excess of 1.25 times the MOP or previous test pressures, and should have been further confirmation of the need of an SIAP for this segment of the Pegasus Pipeline.

Review of the 2006 hydro failure metallurgical test reports indicates that there is not enough evidence to support the theory that the lower temperatures influenced a change from ductile to brittle behavior in a manner that would have caused the failures at lower test pressures as hypothesized by EMPCo. Results of the CVN testing showed little to no variation in the CVN values at the various temperatures and certainly not enough to account for failures at lower test pressures [see Tab E, page ii]. The fact that the test temperatures were well within the design temperature range for normal operations of the pipeline should be enough to discount the test temperature's influence on the lower test pressure statements by EMPCo. Tab H discusses the subject of toughness, and with respect to fatigue, the Baker Report excerpted in Tab H states:

> *Some types of autogenous seams possess exceptionally low toughness (less than 1 ft-lb) on the bondline. Consequently, they are incapable of sustaining much, if any, subcritical extension of initial flaws originating at the pipe mill. And in fact, fatigue failures of bondline flaws in low-toughness seams do not occur. Bond-line flaws in low-toughness seams are susceptible to the phenomenon of "pressure reversals" wherein a defect fails at a lower pressure than a recent prior high-pressure level. These failures evidently experience an exhaustion of the limited available ductility during a high- stress event, reducing the capacity for subsequent high-stress events, in effect a form of ultra-low- cycle fatigue.*
>
> *On the other hand, hook cracks, while uniquely associated with ERW or EFW seams, are not true bond-line flaws. They reside slightly off the bondline where even the HAZ material has sufficient ductility to sustain subcritical flaw growth. Hook cracks are thus prime candidates for fatigue in service if the operating pressure spectrum is conducive.*

Visual evidence included in the metallurgical report for the location at MP 243.8 and MP 190.3 indicated possible growth of the hook cracks prior to the final failure. Comments about thinning of the wall due to external corrosion at the ERW were included in the metallurgical summary for the report at MP 294.1. It was noted that there was no discussion in any of the EMPCo documentation related to consideration of pressure reversals, interactive threats such as corrosion resulting in a reduction of wall thickness and manufacturing defects, or elevated pipe-to-soil potentials and the possibility of hydrogen embrittlement (the latter two of which are different mechanisms from grooving corrosion), but certainly are other threats that should be considered in investigations carried out by EMPCo related to pre-70 ERW failures.

--end--

TIMELINE	Patoka to Doniphan 175.68 Miles HCA Miles 173.40 (98.7%)	Doniphan to Conway 142.49 Miles HCA Miles 141.92 (99.6%)	Conway to Foreman 163.63 Miles HCA Miles 160.46 (98.1%)	Foreman to Corsicana 166.63 Miles HCA Miles 158.13 (94.9%)
1984 In-service Leak	-	-	one (1)	-
1991 Hydrotest Failures	none (0)	none (0)	three (3)	none (0)
Baseline ILI	7/20/01 ILI Enduro Caliper, Tuboscope Wall Loss	7/15/2001 ILI Enduro Caliper, Tuboscope Metal Loss	7/9/01 ILI Enduro Caliper, Tuboscope Wall Loss	8/28/99 Pipetronix/PII
1999 & 2001 ILI Results	26 Digs - (24) 60 Day, (2) 180 Day	44 Digs - (35) 60 day (15) 180 Day. 4 Digs completed in 2002, 40 in 2005	54 Digs - 28 in 2001/2002 [(24) 60 Day, (3) 180 Day], (1) non-HCA, and 26 in 2005	45 Digs - 22 Digs in 1999/2000, 23 Digs in 2005, (28) 180 Day
2005 Pressure-Cycle-Fatigue Analysis Date and Results	2/10/2005 Results: Light to Moderate at All Locations Modeled - 8 Pump Stations, Modeled 8 days data, CVN = 25, 1991 Hydrotest Records, Station Discharge Limited to 805 psig, Approximately 300 cycles per year			
2005-2006 Hydrotest	12/17/2005	1/17/2006	2/24/2006	3/17/2006
2005-2006 Hydrotest Failures	(8) - 5 Seam Failures and 3 Girth Weld Pinholes	(1) - Seamless Pipe	(6) - All Seam Failures	none (0)
Updated Risk Scores	Revised 6/29/2006 D(616.8) 3(184.3)	Revised 7/7/2006 D(602.2) 3(229.3)	Revised 7/27/2006 D(573.9) 3(258.7)	Revised 8/16/2006 D(585.9) 3(198.4)
Identified Threats	none (0)	none (0)	none (0)	none (0)
Recommended Next Inspection	12/17/2010 - Based on hydro and pressure-cycle-fatigue analysis	1/17/2011 - Based on hydro and pressure-cycle-fatigue analysis	2/24/2011 - Based on hydro and pressure-cycle-fatigue analysis	3/17/2011 - Based on hydro and pressure-cycle-fatigue analysis
2007 PipeLife Analysis	July 31, 2001 Benchmark PipeLife Analysis after 1 year of operations. Analysis based upon conclusion by operator of Light to Very Light Cycles, CVN = 7.0 ft-lbs., performed by David Shindo, in-house. Analysis based on minute pressure data over a one month period			
2007 LSFS Analysis	Figure 2.1, Version 3.1 IMP, dated 9/30/2006 Flow chart used Not Susceptible to Seam Failure - Based on PipeLife. Flow chart referenced Kiefner 2002 Paper on Dealing with LF-ERW Pipe…" Advisory Report on IA of Lap Welded Pipe, Draft Standard on Long Seam Susceptibility "Criteria for Determining..." and DOT October 2003 Delivery Order DtRS56-02-D-70036, "Low Frequency ERW and LW Long. Seam Evaluation"			
Combined Testable Segments	Prior to the 2009 LSFS Analyses, the four Testable Segments were reduced to two Testable Segments by combining the Pat-Don and Don-Con segments into the Patoka to Conway Testable Segment, and combining the Con-For and For-Cors segments into the Conway to Corsicana Testable Segment.			

TIMELINE	Patoka to Conway 317.4 Miles HCA Miles 315.32 (99.3%)	Conway to Corsicana 330.37 Miles HCA Miles 318.59 (96.4%)
2009 LSFS Analysis	Long Seam Susceptibility Criteria for Baseline Assessment, Rev. Date 3-24-03 used, dated 10/13/2009, Patoka to Conway 317.4 Miles	Long Seam Susceptibility Criteria for Baseline Assessment, Rev. Date 3-24-03 used, dated 10/13/2009, Conway to Corsicana 330.37 Miles
Figure 4.2 - Tool Selection 2010 Reassessment		Not Susceptible to long seam failure, based upon 2007 PipeLife results and 2005-2006 metallurgicals. Reconsider after Pat-Con TFI tool run and post 2009 Expansion - TBD
2010 In-Line Inspection	6/10/2010 MFL Combo Tool, Vendor - NDT 8/15/2010 TFI Tool, Vendor - GE PII	7/21/2010 Tool removed from line Vendor - NDT, Combo MFL-Geometry tool
Preliminary Report		8/23/2010
Final Report	12/30/2010	1/10/2011
Discovery Declared	3/4/2011	3/15/2011
2011 LSFS Analyses	2/24/2011 - Circular Logic, notes fatigue failures in 2005-2006 were due to hydro pressure reversal, no fatigue due to normal operation - Not Susceptible	3/3/2011 - Circular Logic, notes fatigue failures in 2005-2006 were due to hydro pressure reversal, no fatigue due to normal operation - Not Susceptible, but Recommended TFI in 2011-2012 on this segment. 3/14/2011 - scheduling TFI tool run for summer 2011, *"Run Risk Model (TIARA) with no Manufacturing Threats"*
2011 Fatigue Analyses	3/3/2011 Summary Letter, completed by Manny Cortez in February 2011. CVN = 7, one month's worth (Feb 2011) of minutely pressure data, all light to moderate cycles, predicted minimum retest 9.21 and 9.49 years, based upon 2005-2006 hydro for starting point of interval for this segment	3/3/2011 Summary Letter, completed by Manny Cortez in February 2011. CVN = 7, one month's worth (Feb 2011) of minutely pressure data, all light to moderate cycles, predicted minimum retest at 7.4 years, based upon 2006 hydro for starting point.

TIMELINE	Patoka to Conway 317.4 Miles HCA Miles 315.32 (99.3%)	Conway to Corsicana 330.37 Miles HCA Miles 318.59 (96.4%)
Updated Risk Scores System 2A Attachment #7	2/24/2011 **C4** C(522.7) 4(159.6) This was the score after completing the 2010 TFI Tool Run and reflected the findings of the assessment	3/7/2011 **D3** D(542.8) 3(190) This score assumed the 2011 TFI Tool Run would be completed in the summer of 2011
2011 Form 3.2 - D.I.	n/a	Form 3.2 Completed 3/15/2011 for Combo ILI Results 52 Digs - (3) Immediates, (5) 180 Day, (43) prior to Next Assessment, 1 non-HCA. Noted - Before Year-end 2011 run TFI tool. No Identified Threats
2011 Post Assessment and P&M as documented on Consolidated Forms	8/15/2011 - Completed P&M Analyses documented on Forms 6.2, 6.2, 6.3. DI Form 2.2 Completed No Additional P&M measures, Risk Matrix - C4. Noted - Line operates at less than 65% SMYS	7/21/2011 - Completed P&M Analyses documented on Forms 6.2, 6.2, 6.3. DI Form 2.2 Completed No Additional P&M measures, Risk Matrix - D3. Noted - Lake Maumelle watershed and Cedar Creek Reservoir noted as extra sensitivities and recommended cost/benefit determination for possible addition of 4 EFRDs.
2011 MOC - Reschedule TFI	n/a	11/15/2011 - MOC completed to reschedule TFI run from 2011 to 2012 due to fiscal concerns. 3/14/11 e-mail states that HCA Team decided to reschedule due to budget constraints caused by combo repairs. Relied on PipeLife interval of 7.4 years from 2006 hydrotest
2012 Fatigue Analysis	7/20/2012 Analysis performed by Gaby Paez. M2012 Pressure data, CVN = 7 ft-lbs, PipeLife - Type 2, 2005-2006 hydrotest data, resulted in 5 segments with Maximum Retest Intervals in the Past. Notes explained that the pipeline operated this way only since 2009 expansion	
2013 TFI Tool Run	n/a	2/6/2013 - TFI tool run, Vendor - GE PII
2013 MP 314.77 Failure		3/29/2013 - Seam Failure at MP 314.77

1991 Segment	MP	Date	Pressure	1991 Test Failures	2006 Segment	MP	Date	Pressure	Test Failures
CORSICANA STATION	**0**	-			**CORSICANA STATION**				
HO-1815	0.00 - 27.49	7/31/1991			27	0.01 - 27.49	3/17/2006	1054.5	
HO-1816	27.49 - 71.46	7/30/1991			26	27.49 - 66.64	3/13/2006	1073	
HO-1817	71.46 - 82.72	7/31/1991							
HO-1817A	76.77 - 82.72	8/5/1991			25	66.64 - 82.72	3/13/2006	985.5	
QUITMAN STATION	**82.78**	-			**QUITMAN STATION**				
HO-1818	82.72 - 98.49	8/4/1991			24	82.72 - 98.49	3/5/2006	1068	
WINNSBORO STATION	**98.51**	-			**WINNSBORO STATION**				
HO-1819	98.49 - 159.26	8/4/1991			23	98.49 - 127.88	3/5/2006	1030	
AR-TX Border in HO-1820	**Red River MP 159.85**	-			**AR-TX Border in HO-1820**				
HO-1820	159.26 - 166.54	8/4/1991	1031		22	127.88 - 160.62	3/3/2006	1034	
-	-	-			21	160.62 - 166.54	3/3/2006	1034	
FOREMAN STATION	**166.63**	-			**FOREMAN STATION**				
HO-1821	166.54 - 177.13	8/7/1991	1117		20	166.62 - 182.99	2/13/2006	1087.5	
HO-1822	177.13 - 217.06	8/8/1991	1115		19	182.99 - 217.06	2/24/2006	1031.5	2 ERW Seams
HO-1823	217.06 - 238.16	8/7/1991	1041		18	217.06 - 238.16	2/7/2006	993	
GLENWOOD STATION	**238.2**	-			**GLENWOOD STATION**				
HO-1824	238.16 - 257.50	8/14/1991	1153	Seam Failure	17	238.25 - 257.5	2/20/2006	1027.5	2 ERW Seams
HO-1825	257.50 - 299.40	8/13/1991	1124	1984 Leak MP 285.9	16	257.5 - 283.64	1/29/2006	1051.5	
-	-	-			15	283.64 - 299.41	2/1/2006	955	2 ERW Seams
HO-1826	299.40 - 310.65	8/12/1991	1110	Seam Failure	14	299.41 - 312.64	1/24/2006	1108	
HO-1827	310.65 - 330.12	8/15/1991	1090	Seam Failure	13	312.64 - 330.12	1/24/2006	1091	
HO-1840	310.650 - 312.64	8/14/1991	1092		-	-	-	-	
CONWAY STATION	**330.24**	-			**CONWAY STATION**				
HO-1828	330.12 - 366.35	8/19/1991	1167		12	330.28 - 368.42	1/17/2006	1161	
HO-1829	366.35 - 387.76	8/17/1991	1075		11	368.42 - 390.83	1/17/2006	1162	
HO-1830	387.76 - 410.29	8/17/1991	1027		10	390.83 - 410.29	1/11/2006	1043.5	
STRAWBERRY STATION	**410.34**	-			**STRAWBERRY STATION**				
HO-1831	410.29 - 437.74	8/23/1991	1160		9	410.29 - 437.74	1/10/2006	1164	
MO-AR Border in HO 1832	**455.7**	-							
HO-1832	437.74 - 472.57	8/23/1991	929		8	437.74 - 472.57	12/20/2005	1021	1 Seamless
DONIPHAN STATION	**472.64**	-			**DONIPHAN STATION**				
HO-1833	472.57 - 496.30	8/26/1991			7	472.70 - 496.3	12/17/2005	1081	
HO-1834	496.30 - 544.44	8/25/1991			6	496.30 - 529.84	12/10/2005	1008	1 ERW Seam
					5	529.84 - 544.44	11/29/2005	1113	
YOUNT STATION	**544.47**	-			**YOUNT STATION**				
HO-1835	544.44 - 554.52	8/28/1991			4	544.50 - 554.52	11/9/2005	1189	
HO-1836	554.52 - 572.28	8/28/1991			3	554.52 - 572.28	11/8/2005	1105	
HO-1837	572.28 - 604.98	8/28/1991			2	572.28 - 604.98	11/2/2005	1123	
HO-1838	572.28 - 576.34	8/28/1991			-	-	-		
IL-MO Border in HO 1838	**573.7**	-			**STEELEVILLE STATION**	**587.74**	**(Added After 2006 Test)**		
HO-1839	604.98 - 647.73	9/1/1991			1	604.98 - 647.73	11/23/2005	1005	4 ERW Seams
PATOKA STATION	**647.75**	-			**PATOKA STATION**				

--end--

Baker Report OPS TTO5 REV 3 – Excerpts from Chapters 7 and 8

7.2 Fatigue Mechanics

"Fatigue" is the process of initiation of a crack, propagation of the crack (i.e., enlargement of the crack), and final fracture of the crack as a result of elapsed cycles of applied stress in service. These three processes are distinct phases and although they occur sequentially, are governed by separate considerations.

7.2.1 Initiation

Initiation of fatigue occurs at nucleation sites within the material such as inclusions, pores, soft grained regions, or as they become generated through microvoid coalescence by the straining process. The presence of macroscale stress concentrators, or more accurately strain concentrators, such as grooves, notches, threads, weld toes, manufacturing flaws, or similar features, enhances this process. However, fatigue can occur eventually if stress cycles are sufficiently numerous and large in magnitude even if the material surface is apparently free of such features. (So many more cycles of stress are required in this latter scenario than would be expected in a pipeline application, that fatigue initiation in the absence of macroscopic strain concentrating features is not a scenario of interest in a pipeline context.)

The number of cycles of a given stress level required to initiate a crack in the area of stress or strain concentration is inversely proportional to the local notch acuity or notch root radius. In other words, a sharp notch will be more prone to form a fatigue crack than a blunt notch when subjected to equal cyclical loading conditions. Similarly, the number of cycles of loading necessary to initiate a crack is inversely proportional to the magnitude of the stress variation. Consequently, a fatigue crack will initiate sooner if the stress cycles are larger, for any given notch-like geometry.

The initiation behavior of a material is described by an "S-N" curve, which is a graph of the magnitude of cyclical stress range or amplitude S plotted against the number of cycles of that stress that would cause failure N. An example is shown in Figure 7.1. Typically such curves are approximately linear when both axes are logarithmic. This curve may be interpreted to indicate that larger amplitude stress cycles result in failure in fewer cycle occurrences, while smaller stress cycles result in failure after a greater number of cycles. At a sufficiently low magnitude of stress cycle, the S-N curve may flatten out, indicating an "endurance limit", which represents a magnitude of stress cycle below which a fatigue failure would not be expected no matter how many cycles accumulate. A basic S-N curve represents the nominally smooth un-notched condition, while more severe curves can be developed for notches having increasing local stress-concentrating effects. The S-N curves are empirically derived from large numbers of separate tests in which standard round bars of materials are cyclically loaded to specific nominal stress levels until fracture occurs. The S-N curve therefore actually encompasses all three phases of fatigue: initiation, propagation, and fracture, but since the specimens start out nominally free of defects other than a specified notch that may be present, the initiation phase is by far the largest proportion of the total test life in terms of loading cycles (e.g., 90% or more).

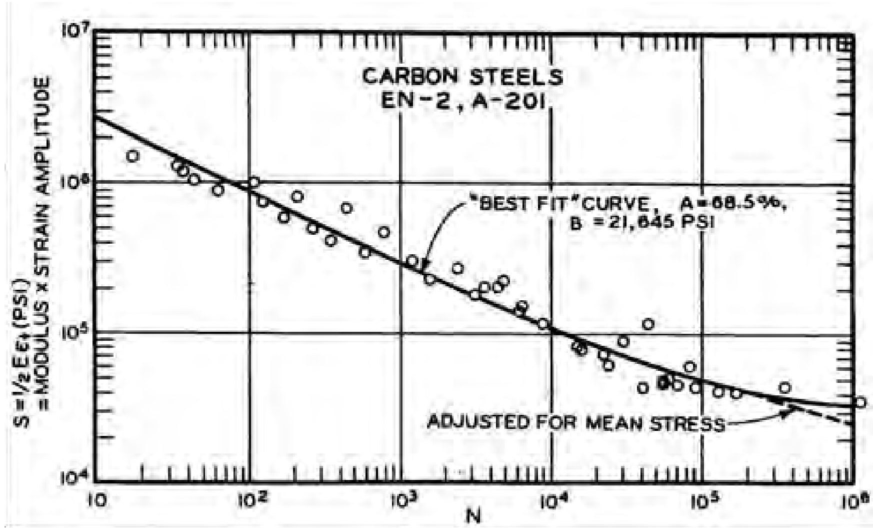


Figure 7.1 A Representative S-N Curve (ASME)

The resistance to fatigue crack initiation is generally proportional to ultimate tensile strength properties. It is enhanced by improvements in surface finish quality and by treatments that impart compressive residual surface stresses or hardened surface microstructures. If the magnitude of nominal stresses are in the elastic range and only very small potential nucleating features are present, on the order of perhaps millions of cycles of stress will be required in order to initiate a fatigue crack. The fatigue initiation characteristics of a given material, design feature geometry, and loading level are therefore of great interest to designers of rotating machinery, vehicles, aircraft, and highway bridges because such structures rapidly accumulate large numbers of individual stress cycles. The initiation phase of fatigue is also considered in the design of process piping systems that are free to flex in response to changes in operating temperature. Here, the consideration is not that such cycles are particularly numerous but rather that the magnitude of flexural stress cycles in piping components such as elbows and tees are magnified by their geometries such that the range of stress cycle may be much larger than the yield stress. It is also important to consider that the resistance to fatigue crack initiation in steel is adversely affected by some operating environments.

In contrast, the initiation phase of fatigue is of little concern in the pressure design of pipe, because the magnitude of most hoop stress cycles is in the range where millions of cycles would be required, and the number of large-magnitude pressure stress cycles is relatively few. This is substantiated by the fact that there are no known cases of fatigue failures in pipelines due to pressure cycle effects in the absence of some sort of significant initial flaw.

7.2.2 Crack-Tip Stress Intensity

The propagation process concerns a crack that is already present, so it is necessary to consider propagation using parameters related to fracture mechanics. The crack-tip stress-intensity is an expression of the theoretical stress at the tip of a crack, derived from linear elastic fracture mechanics as:

$$K = f(\text{geometry}) \times \sigma \times (a)^{1/2},$$

where

σ is a nominal applied stress,

a is the crack size, and

K is expressed in units of ksi-(in)$^{1/2}$ or MPa-(mm)$^{1/2}$

The mathematical function of geometry produces factors that differ for certain idealized crack configurations such as a through-wall crack in a plate, a crack at one or both edges of a narrow strap, an elliptical crack embedded in a solid body, or a surface-breaking semi-elliptical shape. This last idealized configuration, Figure 7.2, is the principal one of interest in dealing with seam susceptibility issues in line pipe, since the concern is for features having configurations similar to this.

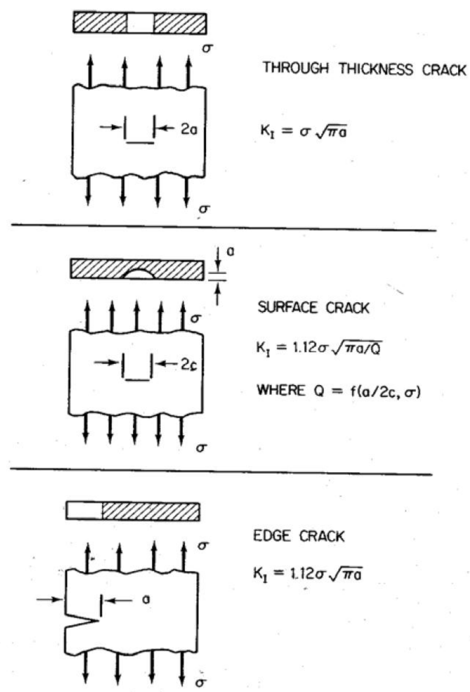


Figure 7.2 Simplified Crack Types (Barsom and Rolfe)

An expression for the crack-tip stress intensity for the semi-elliptical surface flaw is given by Raju and Newman as:

$$K = \sigma\, f\left(\pi \frac{a}{Q}\right)^{1/2}$$

where

$$Q = 1 + 4.595\left(\frac{a}{L}\right)^{1.65}, \quad \frac{a}{L} \le 0.5$$

$$f = M_1 + M_2\left(\frac{a}{t}\right)^2 + M_3\left(\frac{a}{t}\right)^4$$

$$M_1 = 1.13 - 0.18\left(\frac{a}{L}\right)$$

$$M_2 = \frac{0.445}{0.1 + \frac{a}{L}} - 0.54$$

$$M_3 = 0.5 - \frac{0.5}{0.325 + \frac{a}{L}} + 14\left(0.5 - 2\left(\frac{a}{L}\right)\right)^{24}$$

In the above expressions, d is the depth of the crack from the pipe surface, L is the length of the crack, and t is the pipe wall thickness. Researchers have developed refinements or variations to this expression which could also be used, but the one given suffices for evaluating fatigue crack growth in a pipeline seam. If the stress fluctuates over a range Δσ, then the magnitude of the fluctuation in stress-intensity is

$$\Delta K = f(geometry) \times \Delta\sigma \times (a)^{1/2}.$$

7.2.3 Propagation

Propagation occurs from a flaw that either initiated due to the effects of cyclic stresses acting on a strain concentrator or that already existed when the structure entered service. This latter category is of interest to the assessment of the susceptibility of longitudinal seams in pipelines to the effects of pressure cycles because, as discussed above, fatigue failures due to pressure cycles in pipeline seams are only known to occur from some sort of initial flaw.

In every case involving fatigue in autogenous seams (e.g., ERW and EFW pipe), the initial flaws are artifacts of the manufacturing process that escaped detection by the inspection process in the pipe mill and that were also small enough to pass the hydrostatic test at the mill or in the field prior to commissioning. (Note that one type of initial flaw, the origin of which is fatigue in nature, is the "rail shipment fatigue" crack that affected a small population of large-D/t pipe manufactured using the DSAW longitudinal seam. In those cases, pipe joints at the bottom of improperly loaded rail cars developed fatigue cracks at the toes of longitudinal seam weld beads while the pipe was in transit due to the cyclical inertial stresses associated with railcar transient loadings. The fatigue-initiated cracks were small enough to pass the hydrostatic test conducted by the pipeline operator prior to commissioning the pipeline, so the pipes entered service with fatigue cracks already in place. The analysis of *fatigue crack-growth life for such flaws is essentially similar to that for hook cracks in ERW seams. Also, pressure cycle fatigue propagation can occur from SCC or mechanical damage defects in the pipe body, but these are entirely separate issues from longitudinal ERW seam susceptibility.)*

Propagation or growth of a fatigue crack in service is governed by the Paris Law:

$$da/dN = C\,[\Delta K]^n$$

where:

da/dN is the increment of crack extension per load cycle,
ΔK is the magnitude of stress intensity range for a given load cycle, and
C and n are material properties.

The size of the crack, a, thus increases incrementally by da with each load cycle dN while the magnitude of the stress-intensity range, ΔK, a value that encompasses the effect of crack size, a, increases with each increment of crack growth.

The nature of the crack-growth relationship results in an exponential increase in crack growth rate and an acceleration of crack size as load cycles accumulate. The practical implication of this is that a small crack may remain small for a long time, and by the time it is detectable, either by means of in- service examination (e.g., crack detection ILI) or proof load testing (e.g., hydrostatic pressure test), the remaining safe service life could be very short, as suggested in Figure 7.3. Figure 7.3 also shows that a larger initial flaw size greatly reduces the remaining time to failure. This suggests that achieving the largest possible margin between the test pressure and the operating pressure is of value to maximizing the retest or reinspection interval.

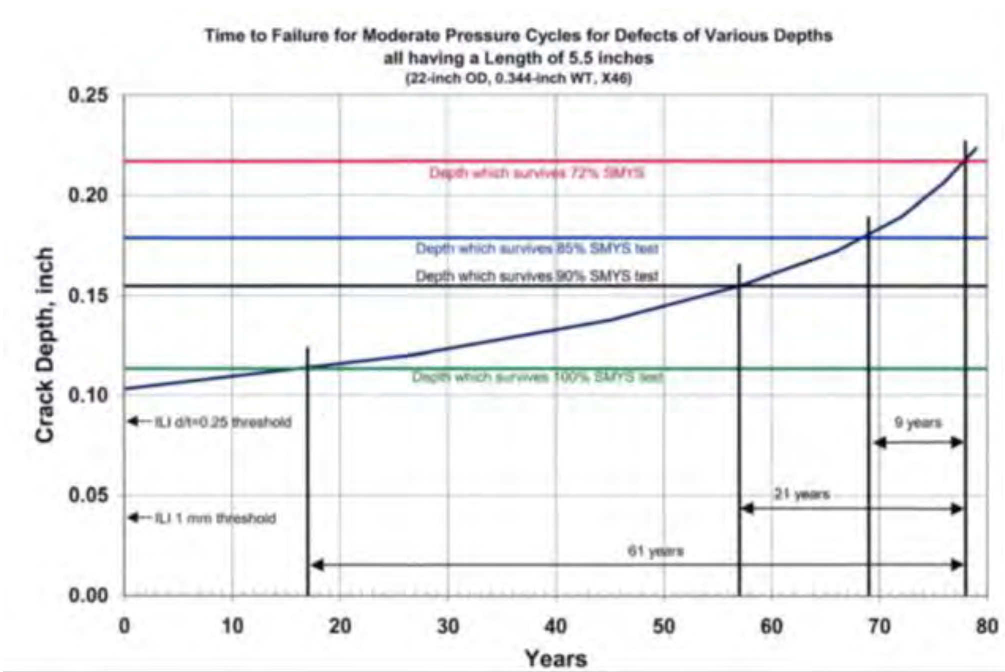


Figure 7.3 Example Crack Growth in Service

A potential value to the highest possible test pressure is the concept of "retardation", wherein an infrequent overload cycle blunts the crack tip and introduces a large plastic zone ahead of the crack.

When the proof load is released, the residual stress field in the plastic zone is compressive, causing a delay in subsequent crack growth. While retardation is a proven phenomenon, it may not occur to a significant degree where the proof test is only 1.25 times the MOP. The effect of retardation is usually disregarded when performing incremental fatigue crack growth computations.

The values of C and n in the Paris Law vary widely. A "typical" value reported for C and n in plain carbon steel is $C=3.6x10^{-10}$ *and n=3.0 for ΔK expressed in units of* $ksi(in)^{1/2}$*, though any given steel might exhibit very different values for the crack growth rate parameters. This "typical" relationship between da/dn and ΔK is shown in Figure 7.4. If ΔK is expressed in units of* $psi(in)^{1/2}$*, then the value of C must be divided by* $[1000]^n$ *giving* $3.6x10^{-19}$*. The value of C can vary by several orders of magnitude, while n has been observed to vary from 2 to 4, though for most pipelines n falls between 2.5 and 3. A higher C and lower n will result in a faster initial crack growth rate that does not accelerate as greatly toward failure, compared to a lower C and higher n which results in very flat initial crack growth rate and more rapid acceleration toward final failure. If only an initial and a final flaw size are known, there is no one combination of C and n that uniquely defines the crack growth curve between initial and final flaw sizes for any given operating spectrum.*

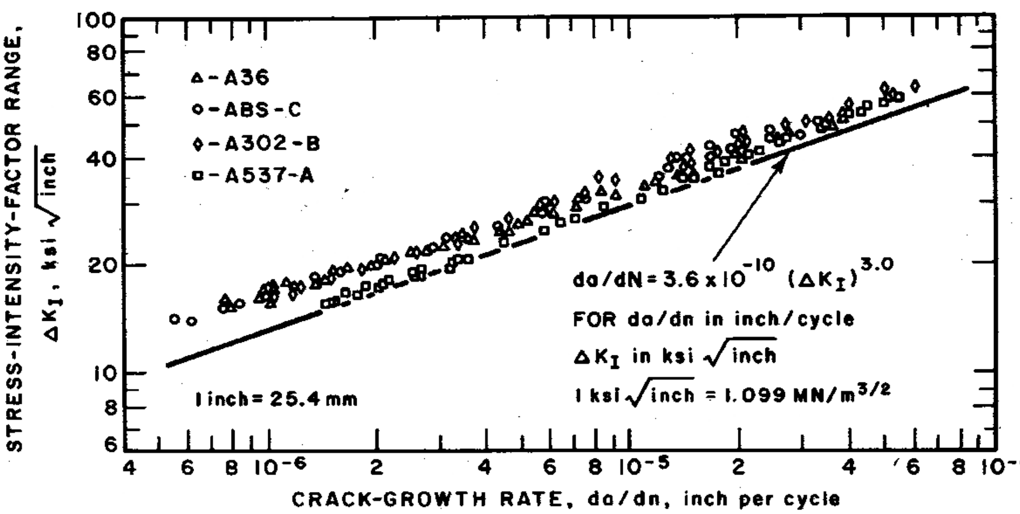


Figure 7.4 Average Crack Growth Rate for Carbon Steel (Barsom and Rolfe)

The values of C and n are influenced somewhat by load cycle frequency and stress ratio (R, the ratio of minimum to maximum stress in a cycle), and are influenced strongly by the chemistry environment that the crack tip becomes exposed to (e.g., dry versus aqueous, or the presence of oxygen, chlorides, sulfur, or hydrogen). The exposure of the fracture to environments at the soil interface, under coatings, or in the pipe interior could greatly enhance crack growth rates compared to those indicated by the "typical" coefficients, making it difficult to obtain reliable predictions of crack-growth life using those values.

7.2.4 Fracture

The final stage of fatigue crack growth occurs when the crack-growth rate accelerates under the influence of ductile tearing and the crack grows to such size as to be critical in service, meaning it could fail at the next applied load cycle. The critical flaw size depends on the nominal stress, the material strength, and the fracture toughness. The relationship between these parameters for a longitudinally oriented defect in a pressurized cylinder is expressed by the NG-18 "ln-secant" equation:

$$\frac{C_V \pi E}{4 A_C L_e \sigma_f^2} = \ln\left[\sec\left(\frac{\pi M_S \sigma_H}{2\sigma_f}\right)\right]$$

E is the elastic modulus,
L_e is an effective flaw length equal to the total flaw length multiplied by π/4 for a semi-elliptical flaw shape common in fatigue,
σ_f is the flow stress typically taken as the yield strength plus 10 ksi or else as the average of yield and ultimate tensile strengths,
σ_H is nominal hoop stress due to internal pressure,
C_V is the upper shelf CVN impact toughness,
A_c is the cross-sectional area of the Charpy impact specimen. (Note that a constant for compatibility of units between C_V and A_c may be necessary.)

The term M_S is a stress magnification factor for a surface-breaking axial flaw, calculated as

$$M_S = \frac{1-(d/t)(M_T)^{-1}}{1-d/t}$$

where
d is flaw depth and
t is the pipe wall thickness.

The term M_T is Folias' original bulging factor for a through-wall axial flaw, written as
$M_T = [1+0.6275(z)-0.003375(z)^2]^{1/2}$, $z = L_e^2/(Dt)$ less than or equal to 50
or
$M_T = 0.032(z)+3.3$, $z > 50$.

In simplified form, this equation forms the basis for common flaw assessment methodologies such as ASME B31G and RSTRENG. The program KAPA solves a similar equation for failure pressures of irregular shaped defects including cracks. For crack-like defects the user must supply a representative value of Charpy energy as well as the yield strength of the material and the detailed dimensions of the defect. KAPA also can be used to evaluate corrosion-caused metal loss without the need for specifying the Charpy energy because the failure pressure levels of blunt defects depend only on the tensile properties of the material.

The NG-18 equation can be understood in practical terms by a review of Figure 7.5 showing the failure pressures predicted by the NG-18 Equation for a given pipe size and material plotted as a function of flaw length and flaw depth (d/t). Several important observations can be made:

- *At any given stress level, there is no single flaw size that is critical. Rather, a range of flaw sizes from short-but-deep to long-but-shallow may be equally critical at a given pressure level.*
- *Short-but-deep flaws tend to leak, while long-but-shallow flaws tend to rupture.*
- *The failure stress level decreases as the flaw becomes either deeper or longer, or both.*
- *The size of flaws that are critical decreases as the stress due to internal pressure increases.*
- *If one were to repeat the analysis considering very low toughness, all of the curves would compress toward the lower left, with the result being that only very short flaws could be tolerated even at low stress levels.*

This last point illustrates the main influence of toughness levels on fatigue in a pipeline. Crack- growth rates (e.g., da/dN as a function of ΔK) are not affected by toughness. Rather toughness determines the largest flaw that could survive a hydrostatic test of the pipe (in other words, the size of the initial flaw prior to the occurrence of fatigue in service) as well as the size of flaw that fails in service. The difference between these two flaw sizes provides the margin for subcritical crack growth in service. Ironically, this difference may be less, and therefore the number of cycles to failure may be less, for a high-toughness material because the initial flaw size that survives a hydrostatic test can be much larger than would be possible in a low-toughness material.

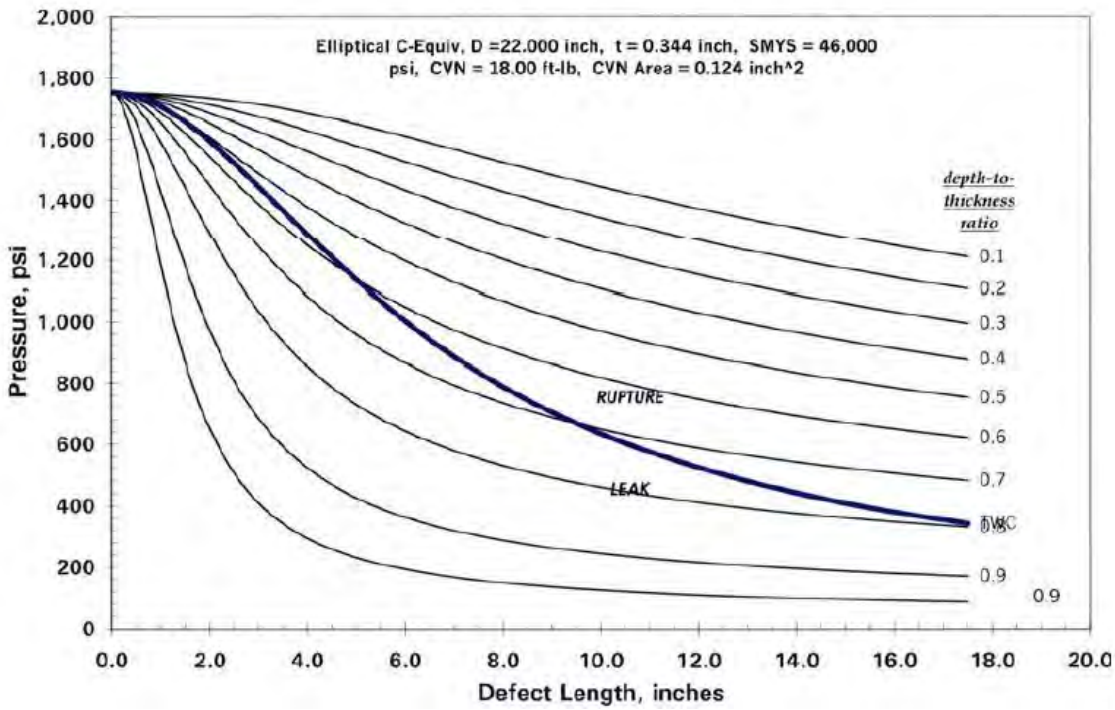


Figure 7.5 Example Relationship Between Failure Stress and Flaw Size

Some types of autogenous seams possess exceptionally low toughness (less than 1 ft-lb) on the bondline. Consequently, they are incapable of sustaining much, if any, subcritical extension of initial flaws originating at the pipe mill. And in fact, fatigue failures of bondline flaws in low-toughness seams do not occur. Bond-line flaws in low-toughness seams are susceptible to the phenomenon of "pressure reversals" wherein a defect fails at a *lower pressure than a recent prior high-pressure level. These failures evidently experience an exhaustion of the limited available ductility during a high- stress event, reducing the capacity for subsequent high-stress events, in effect a form of ultra-low- cycle fatigue.*

On the other hand, hook cracks, while uniquely associated with ERW or EFW seams, are not true bond-line flaws. They reside slightly off the bondline where even the HAZ material has sufficient ductility to sustain subcritical flaw growth. Hook cracks are thus prime candidates for fatigue in service if the operating pressure spectrum is conducive.

7.3 Material Testing and Experience

7.3.1 Standard Materials Tests

Standard material properties tests include yield and ultimate tensile strength, elongation, chemistry, resistance to dynamic fracture propagation as indicated by the CVN impact toughness, and resistance to static fracture initiation in welds as indicated by the CTOD test. The tests for tensile properties and notched impact toughness called for in API 5L should be carried out in accordance with ASTM A370.

The tensile and notched impact tests are carried out in pipe body material. There are two reasons why toughness tests are not performed on the ERW seam. One is that it is difficult to do reliably: the bondline is so narrow that the chances of getting the V-groove properly aligned so that the fracture initiates and propagates along it are poor. Secondly, test results from the bondline would not really matter: if the seam was normalized it would exhibit toughness on a par with the base material, and if the seam had low toughness a fracture mechanics analysis would indicate that from a practical standpoint only very small flaws could be tolerated anyway. For low-toughness seams, the only flaws that are going to grow by fatigue are hook cracks, which are off the bondline.

The CVN impact test impacts a machined bar specimen in 3-point bending with a swinging hammer having known kinetic energy at the impact point. As the specimen fractures, starting at the notch machined at a position opposite the hammer impact point, it absorbs energy and slows the hammer. The amount of energy absorbed is inferred from the angle of the hammer swing beyond the impact. The CVN test measures resistance to fracture propagation under dynamic conditions, a property important to determining the burst pressure and fracture arrest characteristics of pipe. Conducting the test on material samples at a number of different temperatures will demonstrate a transition in absorbed energy, from low values at low temperatures, to much higher values at warm temperatures as shown in Figure 7.6. The low end of the curve corresponds to brittle fracture, while the upper end of the curve corresponds to ductile fracture. Ductility is determined by measuring the proportion of the surface area that exhibits brittle or ductile shear appearance on the exposed fracture surfaces of the specimens. The fraction of shear appearance on the fracture surface undergoes a transition that parallels the trend in absorbed energy. The temperature at which the specimens exhibit 50% shear appearance defines the FATT. The temperature at which the specimens exhibit 85% SATT defines the minimum temperature at which, for all practical purposes, full upper-shelf behavior can be expected, because the additional 15% of shear fracture provides very little additional energy- absorbing capability. The FATT and SATT are independent of tensile properties or yield strength grade designation. They are a function of grain size, which is a physical characteristic that results from the rolling and heat treatment history of the steel.

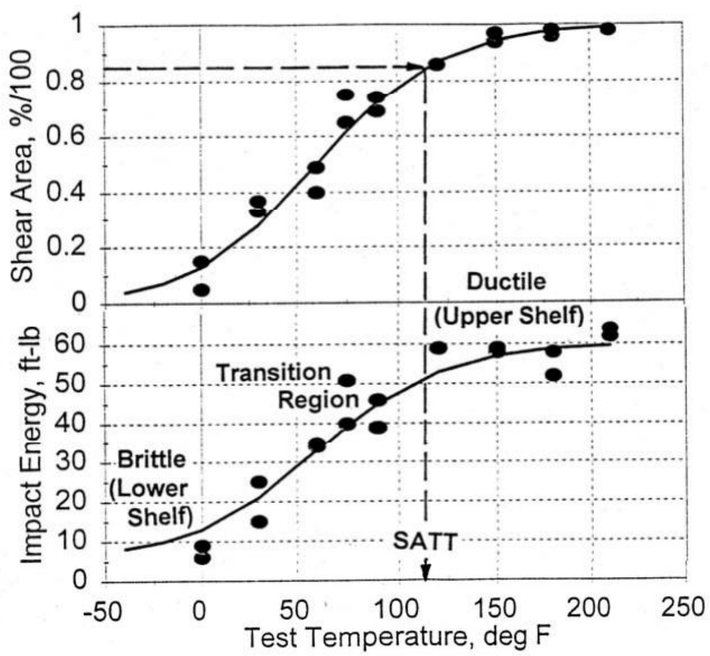


Figure 7.6 Schematic CVN Test Results

It is not uncommon for older pipe to operate at a temperature below the SATT, which means that in the event of a rupture, it is susceptible to fracture propagation in a brittle manner. Such pipe may still initiate the fracture in a ductile manner, it operates at a temperature that is within 60°F to 100°F below the SATT. Moreover, the pipe can continue to be evaluated for corrosion using corrosion assessment methodologies that presume ductile initiation behavior, such as ASME B31G or RSTRENG. The reason for this seeming inconsistency is that the transition in ductility is affected by the strain rate. High strain rates associated with dynamic events (such as impact, or in the context of pipelines, the popping through of a surface crack to form a through-wall crack and subsequent propagation down the pipeline under the influence of line pressure) elevate the transition temperature compared to the static initiation transition, as shown in Figure 7.7.

The resistance to fracture initiation under static conditions is measured by the CTOD test. The CTOD test involves measurement of crack-mouth opening displacements versus applied load, using a specimen containing a fatigue pre-cracked notch, loaded in 3-point bending. If the CTOD test were conducted over a range of temperatures, it would exhibit a transition similar to what is observed with CVN tests, but at a temperature that is 60°F to 100°F lower. It is a much more costly test to perform than the CVN test. The CTOD test is sometimes used to measure the ductility of girth welds, because they are usually not loaded in a manner where dynamic fracture resistance is important. The fracture resistance of girth welds is outside the scope of this study.

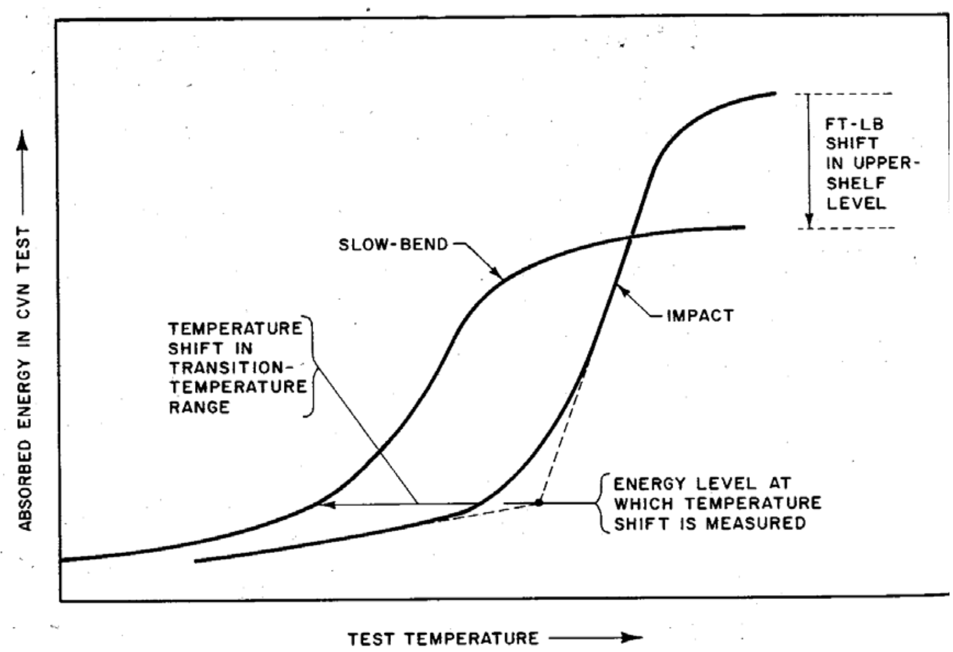


Figure 7.7 Schematic of Strain Rate Effect on Fracture Toughness Transition

7.3.2 Fatigue Properties

Tests performed on various grades of steel plate (some of which may be similar to line pipe plate in terms of chemistry and strength and therefore presumably microstructure and other properties that could affect fatigue crack-growth properties) have indicated that the resistance to fatigue initiation varies with tensile strength while fatigue crack-growth rates (C and n values) vary inversely with strength. However, pipe strength properties probably do not vary over a sufficiently wide range to exhibit significant differences in these properties from grade to grade on the basis of designated strength alone. The fatigue crack initiation and growth properties are far more strongly (and adversely) affected by the chemistry environment at the crack tip.

Crack-growth properties can be measured in the laboratory by conducting a multitude of high- precision tests. It is reasonably safe to state that up to the present, few studies have been undertaken to characterize the Paris Law crack-growth coefficients for specific line pipe steels and varieties of pipe manufacture, and those studies that have did so by backing out effective C and n values by a trial-and-error process of matching initial and final flaw sizes of actual failures using known stress histories, as opposed to specimen testing. There have probably been no studies performed characterizing how C and n are affected by environments that may be present at the ID or OD surface of a pipeline. The fact that such testing is tedious and more expensive than the standard material properties tests normally conducted in the pipe line industry, along with the lack of a perceived need for such tests up until now, has been a barrier. Therefore, the only two practical options available right now to establishing fatigue crack-growth rate coefficients are:

- *Use some sort of average C and n values reported generally for ferritic-pearlitic steels, such as the value cited earlier and illustrated in Figure 7.4, and perhaps modified as reported in literature for the adverse effects of exposure to environments, which may or may not be relevant to pipeline operating environments; or*

- *Develop pipeline-specific effective C and n values derived by trial-and-error calibration of incremental crack-growth computations against a known service failure caused by fatigue using hydrostatic test and operating pressure histories.*

The first option is reasonably straight-forward to apply, but the results can only be used to compare relative effects of different operating scenarios since the estimates of the service life may potentially be quite inaccurate. The second option can be quite accurate (plus or minus a factor of 2 on life) but requires performing a detailed engineering analysis using actual service history and failure data closely related to the situation of interest.

7.4 Using Material Data for Evaluating Flaw Growth

7.4.1 Data Needs and Usage

Data required for an assessment for evaluating the susceptibility to flaw growth of ERW or EFW seam flaws includes the specified minimum yield strength, the Charpy upper shelf absorbed impact energy, the dates and pressures of previous hydrostatic tests, and representative operating pressure records. If for some reason the yield strength is not known, it should be assumed to be around 52 ksi. If the Charpy impact energy is not known, it should be assumed to be around 25 ft-lb (full size) for the base metal. Assuming lower yield strengths or lower toughness values would result in smaller estimated initial flaw sizes, which in turn would lead to longer and potentially non-conservative estimates of crack-growth times to failure.

Before crack-growth computations can be performed, the operational pressure history has to be analyzed by a rainflow cycle-counting procedure, which is a technique for decomposing a random fluctuating signal in order to characterize the quantity and magnitude of cycles. Information from prior failures, if available, should be used to determine applicable flaw lengths. If no such information is available, an assumed flaw length of $2(Dt)^{1/2}$ *would be reasonable and generally in agreement with the lengths of fatigue cracks observed in failures. The critical flaw depth corresponding to the known or assumed flaw length, at the maximum operating pressure and the most recent hydrostatic pressure test, should be determined using the NG-18 equation.*

Crack-growth computations are performed using the Paris Law. In practice, the increment of crack growth is calculated for each load cycle, using the enlarged crack dimension from the previous load cycle in the ΔK *relationship. It is acceptable to maintain a constant flaw length, since enlargement of the flaw along the pipe axis is usually not as significant relative to the flaw's overall severity, as enlargement through the pipe wall.*

Actual pressure fluctuations in service are random and the size of the pressure cycles affects the size of incremental flaw growth, so it is important to maintain the randomness of the pressure cycle sequence, though it is acceptable to repeat the random cycle sequence as a block as many times as necessary to determine the time to failure. Because of the large amount of data processing involved with the rainflow cycle-counting analysis and incremental crack-growth computations, computer algorithms are a practical necessity to carry out the analysis in an accurate and efficient manner.

7.4.2 Example

Consider a 22-inch OD x 0.344-inch WT X46 pipeline being evaluated for susceptibility of fatigue from a hook crack. The CVN upper shelf absorbed energy is 18 ft-lb equivalent from a full-size specimen. The pipeline maximum operating pressure (MOP) is 1,035 psig, corresponding to a hoop stress equal to 72% of SMYS.

The assumed fatigue crack length is $L=2(Dt)^{1/2}=5.5$ inches. The NG-18 equation results in the relationships between flaw size and failure pressure shown in Figure 7.5. At a flaw length of 5.5 inches, a defect would become critical at the MOP at a depth of 64.5% of the wall thickness, or 0.222 inches. If the pipe were hydrostatically tested to a pressure level of 90% of SMYS, a flaw of this length would be critical at a depth of 47.1% of SMYS or 0.162 inch; if the pipe were hydrostatically tested to a pressure level of 100% of SMYS, a flaw of this length would be critical at a depth of 34.1% of SMYS or 0.117 inches.

The best means for selecting C and n values is to benchmark the values against a known incident where the initial flaw size, the final flaw size, a detailed operating pressure spectrum, and the hydrostatic test history are all known. Even so, there is no one combination of C and n that uniquely defines the crack growth curve between initial and final flaw sizes for any given operating spectrum, unless another hydrostatic pressure test or reliable crack-detection in-line inspection occurred some time later in service. The later test or ILI puts an upper bound on how large the flaw could have been at a given point in time. The test may also have left an arrest mark on the fracture surface giving an indication of the flaw size at that time, although it is usually difficult to make such correlations. If only an initial and final flaw size are known with no intermediate test or ILI, then it is not possible to define a unique C and n combination, other than by selecting a reasonable n value, perhaps based on analyses of other pipe of the same type, and changing C to match the known conditions. Considerable judgment is involved in making these choices.

Consider that for the example pipe, it was already established that $C=5.56x^{10-18}$ (K in units of $psi(in)^{1/2}$) and n=2.77 based on prior studies. Figure 7.3 shows the crack growth over time under the influence of a particular operating pressure spectrum that happens to be moderate in terms of cycle aggressiveness. The curve shows failure at the MOP at a flaw depth of 0.222 inches, potentially as early as 9 years after a hydrostatic test to 85% of SMYS, or 21 years after a hydrostatic test to 90% of SMYS, or 61 years after a hydrostatic test to 100% of SMYS if the flaws had the maximum survivable depth at the time of the test.

Figure 7.8 shows the effect on crack growth over time, for this particular case, of more aggressive and less aggressive operating conditions. Figure 7.9 and Figure 7.10 show the effects of greater or lesser values for C with the same n value, and greater or lesser values for n with the same C value, respectively. Note that by pure coincidence, the curve shown for lower C and the same n is almost identical to the curve for the same C and lower n. This result might not necessarily occur with a different operating spectrum, however.

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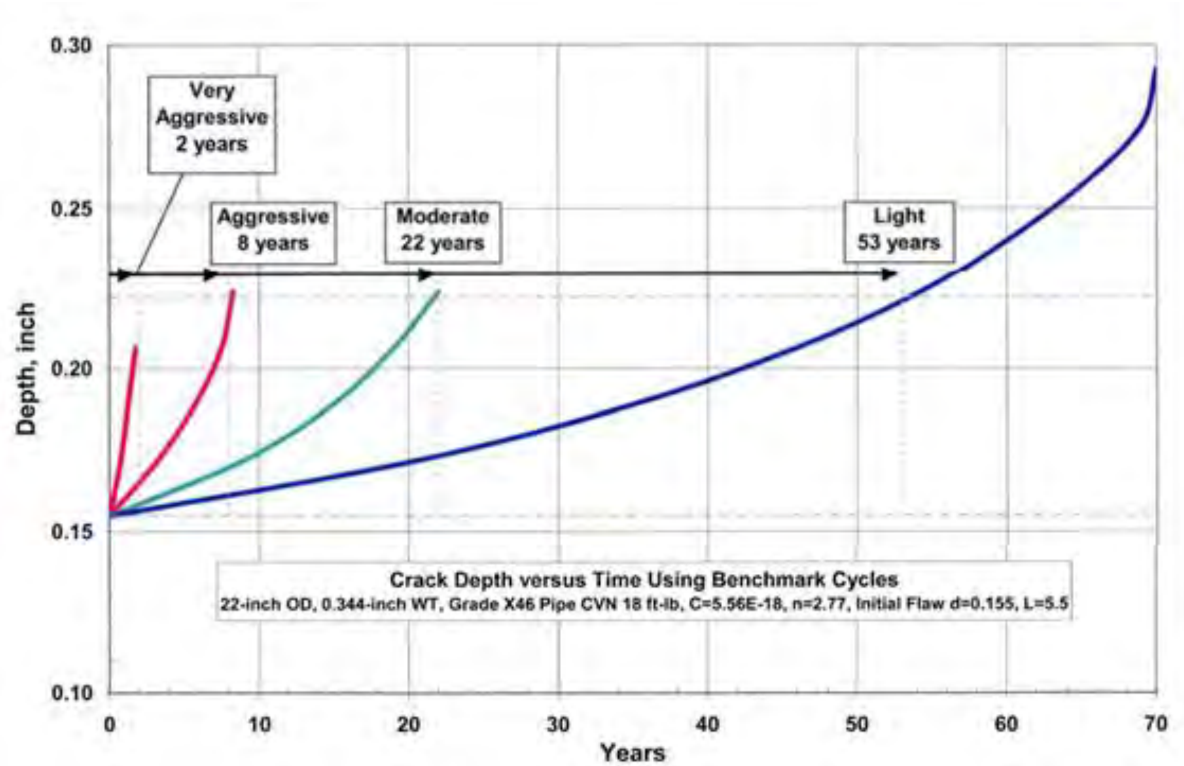

Figure 7.8 Example of the Effect of Operating Pressure Spectrum

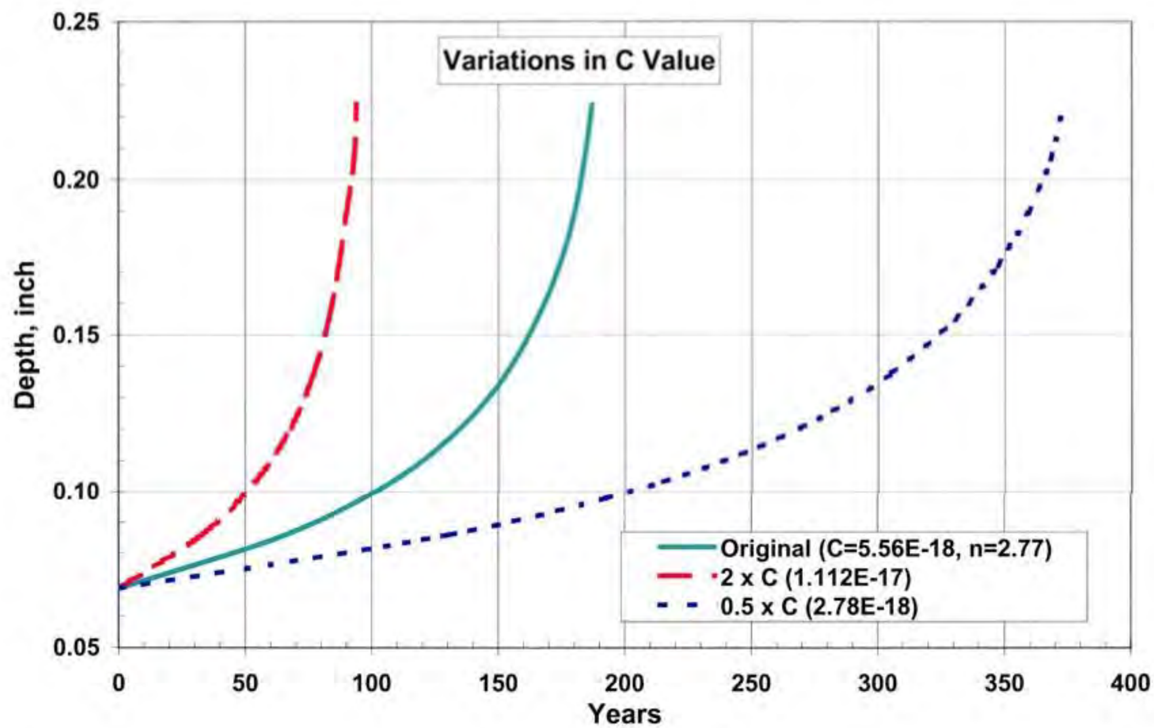

Figure 7.9 Illustration of the Effect of Variations in C

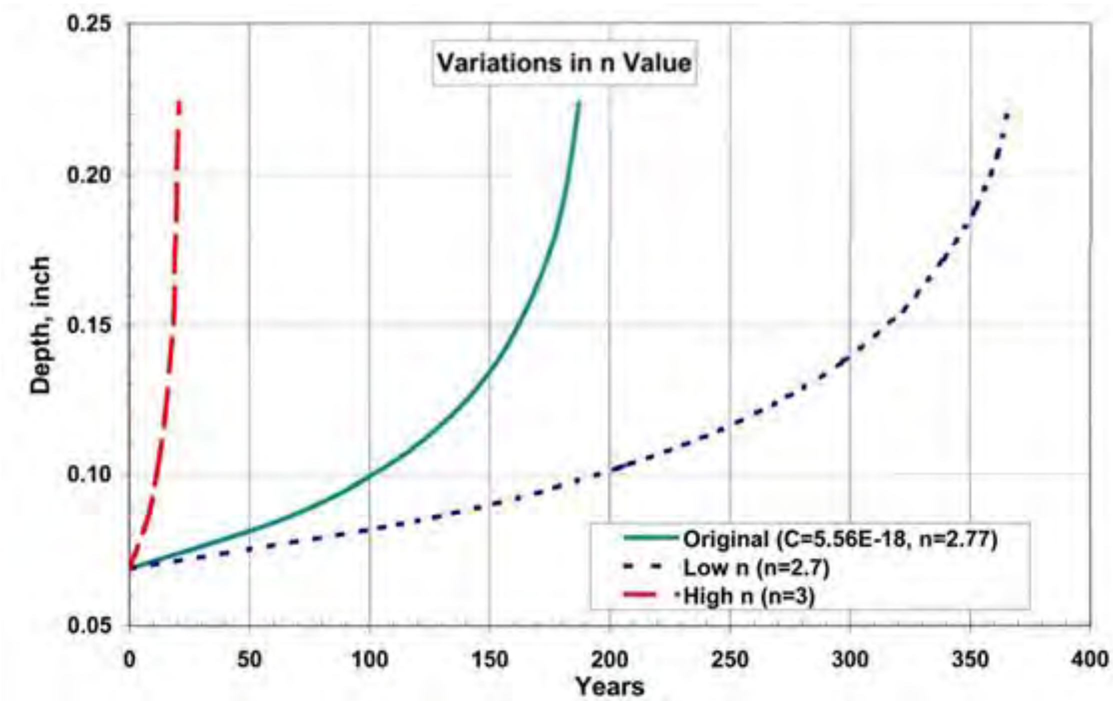

Figure 7.10 Illustration of the Effect of Variations in n

7.5 References

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8.4 Fracture Mechanics Implications for Hydrostatic Testing and In-Line Inspection

Fracture mechanics constitutes a technical discipline through which engineers attempt to understand or predict the effects that defects may have on structures or equipment. Typically, structures and equipment are designed to sustain predictable service loads throughout their useful life without failing. Also, typically, these structures or equipment are proportioned in terms of size and constructed of materials with reliable stress-carrying properties such that they will be continually able to sustain the expected service loads with a margin of safety against failure. Via fracture mechanics, engineers can, in addition, assess the maximum sizes of defects or imperfections that could exist in structures of equipment without causing their intended function to be impaired. As an adjunct to these types of assessments, the responsible engineers or designers may also apply structural-integrity-assessment techniques to assure that no defects beyond the maximum acceptable size exist. This latter activity is precisely the intent of applying either hydrostatic testing or ILI or both to pipelines.

The essential elements of a fracture-mechanics assessment as it is applied to a pipeline situation are the level of nominal tensile stress (usually the pressure-induced hoop stress), the maximum size of a longitudinally oriented defect (usually in terms of axial length and depth penetration through-the wall thickness of the pipe), and the inherent resistance of the pipe material to propagation of the defect either through the wall or along the axis of the pipe. The latter parameter is usually referred to as the "toughness" of the material. In terms of pipeline-integrity assessment, the role these elements may play is typically as follows. To establish the effectiveness of a hydrostatic test, the operator usually needs to compare the sizes of defects that can survive the intended test pressure level to the sizes of those that would cause a failure at the maximum operating pressure. The effectiveness of an ILI depends on being able to detect any and all defects larger than the size at which the associated failure pressure would be less than or equal to a "safe" pressure level above the maximum operating pressure. Because failure pressure is linked to defect size through toughness, the operator must have a reasonable idea of the minimum toughness level that the pipe material will exhibit. It must also be remembered that the inherent toughness of the material is a function of temperature.

To understand the impact of toughness on both hydrostatic testing and ILI, it is helpful to consider Figure 8.1 through Figure 8.5. Each is a failure-pressure-versus-flaw-size relationship for a piece of 16-inch OD, 0.25-inch-wall, API 5L Grade X52 line pipe. On each is a set of nine curves representing defects with uniform depths ranging from 10 percent to 90 percent of the wall thickness. These relationships were generated using the log-secant (NG-18 surface flaw) equation presented in Section 7 and embodied in the RECTANG.xls spreadsheet available free of charge (see www.kiefner.com). On each of the five figures, three horizontal lines appear, one at 1,938 psig (the burst pressure of a defect-free pipe), one at 1,473 psig (corresponding to 90 percent of SMYS), and one at 1,120 psig (corresponding to 72 percent of SMYS). The five figures differ from one another only with respect to the assumed toughness level of the material in each case as defined by a level of CVN energy. The levels of energy portrayed are 500 ft-lb (Figure 8.1), 25 ft-lb (Figure 8.2), 10 ft-lb (Figure 8.3), 2 ft-lb (Figure 8.4), and 0.2 ft-lb (Figure 8.5). It is obvious when one compares these relationships that the level of toughness is very significant with respect to the relationship between failure pressure and defect size.

Because toughness is obviously so important, it is also important to understand (before the impact on integrity-assessment methods is discussed) in what situations these levels of toughness are relevant. First, consider Figure 8.1 where the relationships are based on 500 ft-lb. It will be readily apparent to anyone familiar with line-pipe steels that no ordinary line pipe is capable of exhibiting 500 ft-lb absorbed energy in a CVN test. In fact, Charpy machines typically cannot break a specimen that exhibits more than 250 ft-lb. With today's technology, it is *routinely possible to obtain 100-ft-lb materials (based on full-size specimen equivalent upper-shelf energy) and with special alloys 250 ftlb is not out of reach. But why should we even consider a 500-ft-lb material? The answer is that in the presence of blunt defects such as corrosion-caused metal loss, materials (even old ones) tend to behave as if they had that much toughness. In reality, when a blunt defect fails it does so because the ultimate tensile strength of the material is reached and not because of any crack propagation. Therefore, toughness is irrelevant, and the material behaves as if it had "optimum" toughness.*

Optimum toughness is any level sufficiently high such that the onset of failure is controlled by the attaining of the ultimate tensile strength as opposed to being controlled by the resistance to crack propagation (i.e., toughness). So the purpose of the 500-ft-lb case is to show the effect that various sizes of blunt metal-loss defects can have on the pipe.

Figure 8.2 (25 ft-lb) represents the most commonly encountered scenario with respect to cracks in line-pipe materials manufactured prior to about 1980 when low-carbon thermo-mechanically treated, micro-alloyed line-pipe steels began to emerge in substantial quantities. Generally, this level of toughness is exhibited in all parts of the pipe body including the areas where hook cracks and mismatched skelp edges occur near ERW bondlines (regardless of whether they are low-frequency welded, dc welded, or flash welded). It is also common to see pipe-body materials exhibit this much toughness in static-load situations such as internal pressurization at temperatures well below the ductile-to-brittle transition temperature range. The latter (transition temperature) is determined by means of impact tests such as with CVN tests. It is well known that materials can exhibit ductile behavior at temperatures well below their "transition" temperatures as long as the effective strain rates are relatively low (as in quasi-static-loading situations). So Figure 8.2 represents a very important case with which to consider the effectiveness of hydrostatic testing and in-line inspection.

Figure 8.3 (10 ft-lb) represents a likely "worst-case" scenario for the region near but not in an ERW bondline. This might be the case if the material were extremely "dirty", that is, if it were heavily saturated with nonmetallic inclusions. While this condition is likely to occur only rarely, it needs to be considered in the discussion of the effectiveness of the integrity-assessment methods. This level of toughness may also represent the response of ERW bondlines to grooving corrosion so it is relevant in situations where grooving corrosion could be an issue.

Figure 8.4 (2 ft-lb) and Figure 8.5 (0.2 ft-lb) represent the ranges of effective responses of the bondline regions of low-frequency-welded, dc welded, and flash-welded materials. It is obvious in both figures that these materials are extremely flaw intolerant. At first glance, this tends to be much more alarming than it actually needs to be. As it turns out, both logic and practical experience suggest that once a material such as this receives a satisfactory initial "proof" test, it cannot contain any defects of significant size. Therefore, the relatively small remaining defects pose little or no threat to the integrity of the pipeline because they are too small to become enlarged by fatigue. In fact, the author knows of no case where a small bondline flaw failed because it became enlarged by fatigue crack growth. Moreover, attempts to produce fatigue failures at such flaws within reasonable numbers of cycles have failed.

On the basis of the foregoing discussions, it is now appropriate to discuss the impact of toughness on the effectiveness of hydrostatic testing and ILI. First, consider Figure 8.1 (500 ft-lb), the situation corresponding to corrosion-caused metal loss. Almost any metal-loss tool, even a low-resolution tool, can detect metal loss that is deeper than 30 percent of the wall thickness and longer than ¾ of an inch. Thus, all anomalies lying below the d/t

= 0.3 curve and to the right of a vertical line at 0.75 inch should be detectable. From the standpoint of a hydrostatic test to a pressure level of 1,473 psig, any corrosion with dimensions that place it below the horizontal line at 1,473 psig will be eliminated. From the standpoint of the initial safety margin demonstrated, the ILI gives assurance superior to that of the hydrostatic testing in all cases except for very short pits that fall below the length-detection threshold.

From the standpoint of reassessment interval, one can compare the results of the two types of inspection by noting that after the ILI, if all pits with depths greater than 30 percent of the wall thickness are addressed, the time to failure will be the time that it takes for the pits that are less deep than 30 percent of the wall to grow to the depth level intersected by the horizontal line at 1,170 psig (the maximum allowable operating pressure). If one assumes that defects of all lengths grow at the same rate, then for long defects (greater than 10 inches), the reassessment interval would have to be less than the time it takes for the pits to grow from 30 percent of the wall to about 50 percent of the wall. In this region of the figure, the ILI and the hydrostatic test produce equal times. However, it is clear that for shorter flaws the required time between reassessments goes up for the ILI but down for the hydrostatic test. When one considers this circumstance and the value of knowing where the nonfailed corrosion exists, it is abundantly clear that ILI for corrosion-caused metal loss is far and away the better of the two methods. With the use of a reliable tool and an appropriate follow-up response by the operator to the findings, it is easy to see that ILI alone is the appropriate method for dealing with corrosion-caused metal loss. There is no added value to conducting a hydrostatic test as well. Furthermore, a hydrostatic test by itself would be a less effective means of addressing the problem (assuming that the line is piggable).

Turning to Figure 8.2, one can make a similar comparison between crack-detection tools and hydrostatic testing. In the case of crack-detection tools, the typically advertised detection threshold are (a) depths exceeding 25 percent of the wall thickness and lengths exceeding 2 inches, and (b) depths of 0.04 inch and lengths exceeding 2 inches. In the case of 0.250-inch pipe, the latter depth threshold is a d/t ratio of 0.16. Before proceeding with the discussion, it is worth noting that most fatigue cracks that have been discovered have had lengths exceeding Dt where D is the diameter of the pipe and t is the wall thickness. To date only one fatigue-caused leak with a length less than Dt has been recorded and its Dt was only 0.83 inch. In the case of 16-inch OD, 0.250-inch wall pipe, Dt = 2 inches, so the credible fatigue-crack threats to the pipe would likely involve defects with lengths exceeding the minimum detection threshold of the known tools. Experience has also revealed no case of a fatigue crack longer than about 8 inches. This latter circumstance is significant in terms of ILI effectiveness as discussed below.

Figure 8.2 suggests that the 25-percent depth curve crosses the 1,473-psig line somewhere between 6 and 8 inches. This suggests from the standpoint of safety margin that a reliable crack-detection tool with a 25-percent-depth threshold provides assurance levels superior to that of the 90-percent-of-SMYS test for crack lengths between 2 and about 7 inches. Similarly, a reliable crack-detection tool with a 16-percent-depth threshold provides assurance levels superior to that of the test for crack lengths of 2 to about 10 inches (covering the entire range of fatigue cracks observed to date except for one very short leak). Using reasoning similar to that discussed in conjunction with Figure 8.1, one can ascertain that the reassessment intervals using the tool will be longer than those associated with the use of hydrostatic testing. This point was demonstrated independently in Section 3. The point is that ILI with a proven tool is superior to hydrostatic testing from the standpoint of preventing failures from crack-propagation phenomena as long as the material exhibits reasonable toughness.
Obviously, the lower the detection threshold, the more benefit there is to ILI. It should also be clear that there is no added value to conducting a hydrostatic test in addition to running a reliable crack-detection tool.

When it comes to situations where the toughness of the material, as expressed in terms of Charpy energy, lies well below 25 ft-lb, the superiority of in-line inspection with a crack-detection tool over hydrostatic testing begins to deteriorate. Consider Figure 8.3 in light of the discussions about Figure 8.1 and Figure 8.2 presented previously. Here it becomes evident that the advantage of even the best technology begins to slip away because of the relatively low failure pressures associated with defects having dimensions right at the tool-detection thresholds. For the low-toughness bondline materials as shown in Figure 8.4 and Figure 8.5, the currently available crack-detection ILI tools would provide little if any assurance of integrity. Fortunately, as discussed previously, there is no evidence that the small bondline defects in very low-toughness bondline materials cause time-dependent integrity threats.

In summary, it appears that the use of proven ILI techniques provides a higher degree of integrity assurance than hydrostatic testing (at least to practical limits imposed by the quality of older line pipe materials) for the most important integrity threats (i.e., corrosion-caused metal loss and crack propagation phenomena in materials with reasonable toughness levels). In these cases, hydrostatic testing provides no added value and clearly is inferior to reliable ILI (with appropriate and timely response) used by itself. In those cases where a low or very low-toughness material is involved, however, the reverse is true. In those cases, it appears with today's tool-inspection thresholds that hydrostatic testing would give superior assurance. Also, it is noted that in these cases for reasons explained above, a one-time test would probably suffice, and that one-time test could be either the initial pre-service test or the manufacturer's hydrostatic test if that test was conducted to a sufficiently high level. For cases where the concern is strictly low-toughness bondline, a test to 1.25 of MOP gives sufficient confidence that remaining bondline manufacturing defects will not fail in service. It would seem then that the only reason for employing both ILI and hydrostatic test would be cases where the confidence in the ILI technology needs to be established.

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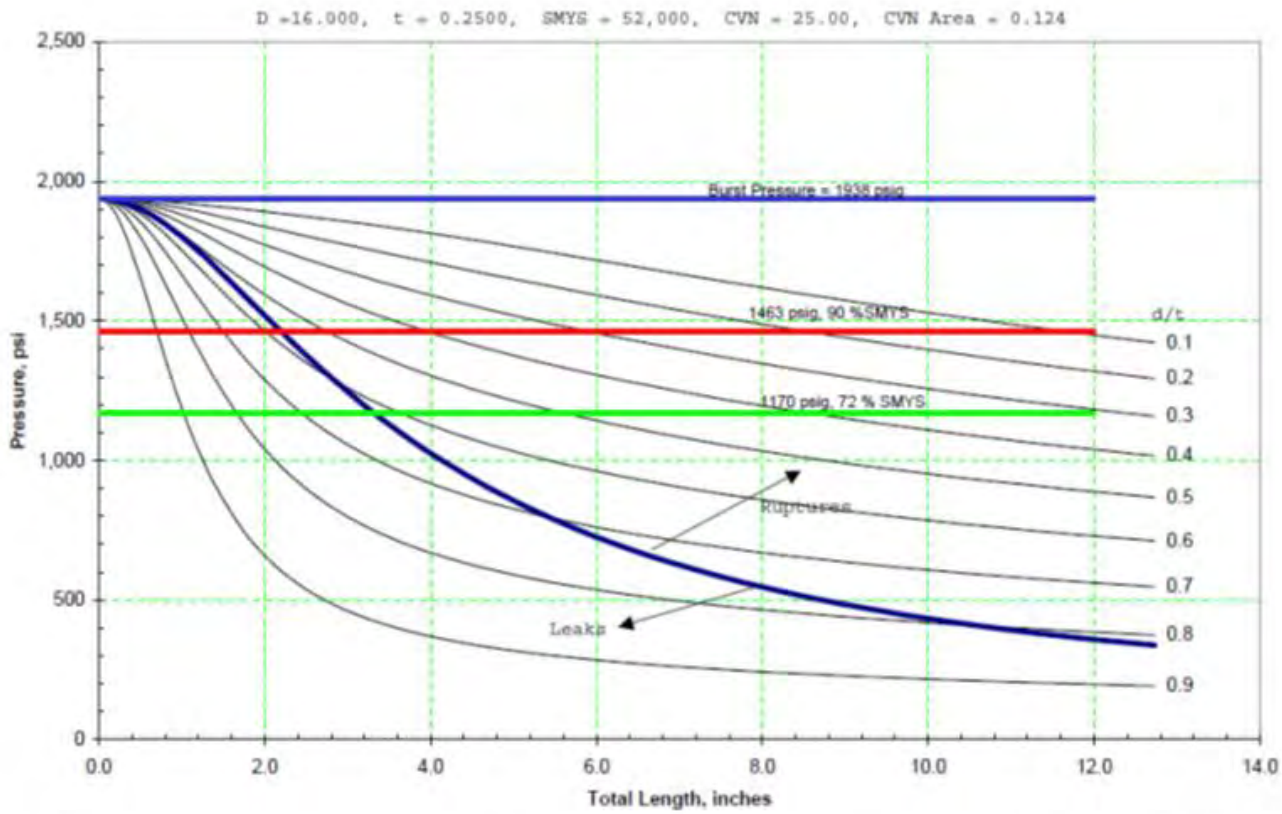

Figure 8.2 Toughness-Dependent Relationship Between Failure Pressure and Flaw Size for Cracks in Pipe Having Normal Toughness Levels (25 ft-lb)

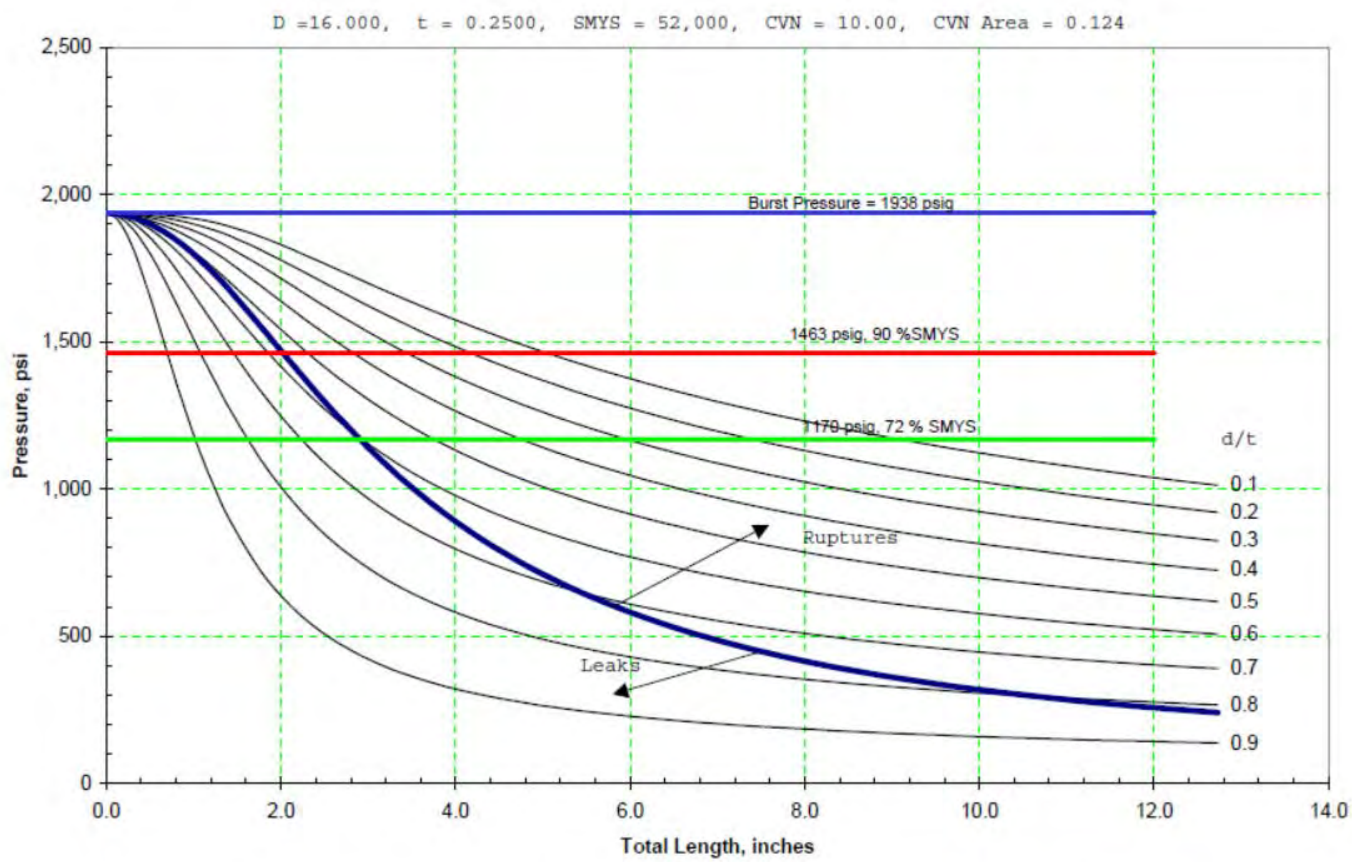

Figure 8.3 Relationship Between Failure Pressure and Flaw Size for Near-Bondline ERW Defects (10 ft-lb)

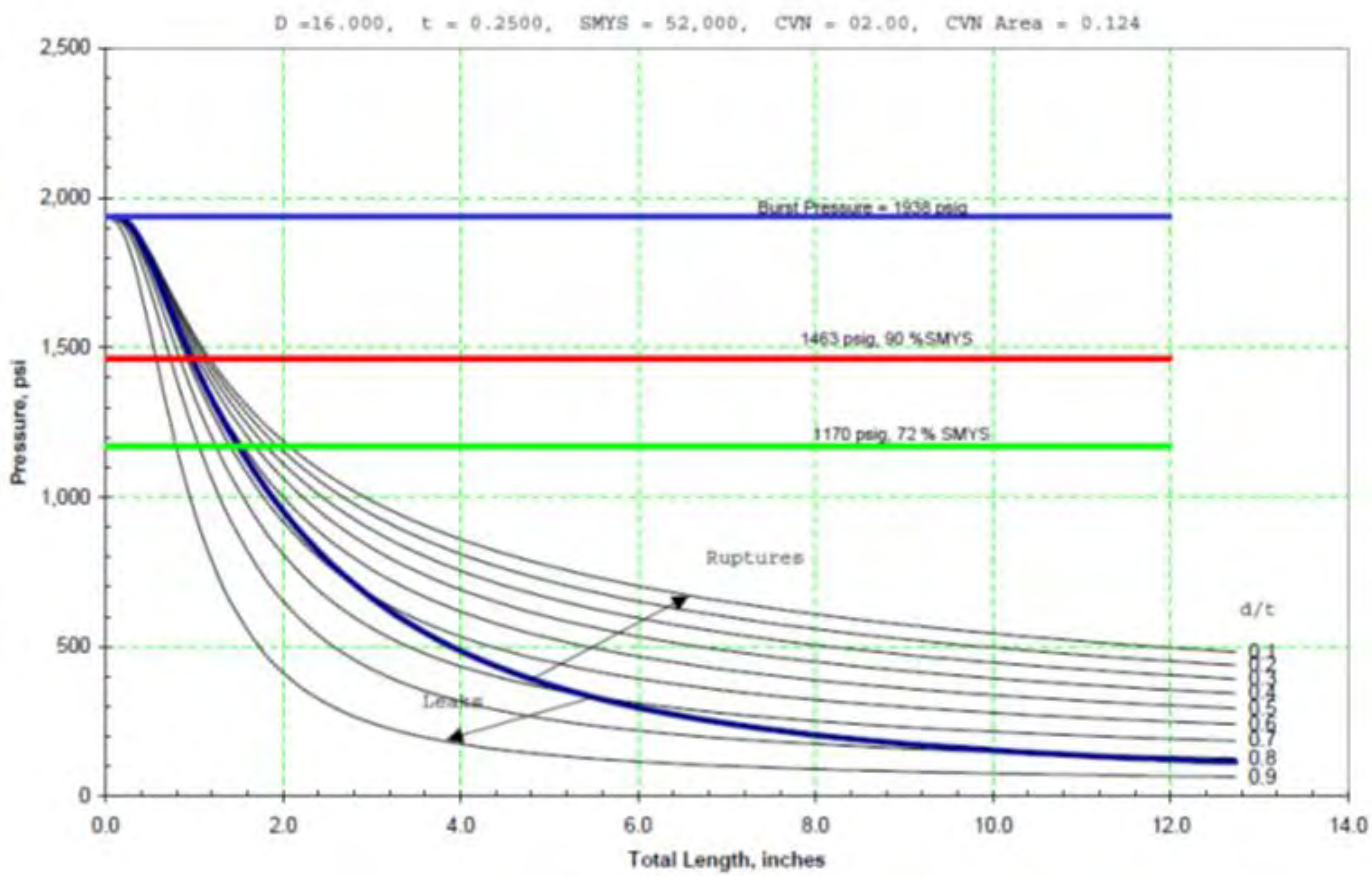

Figure 8.4 Relationship Between Failure Pressure and Flaw Size in Low Toughness Seams (2 ft-lb)

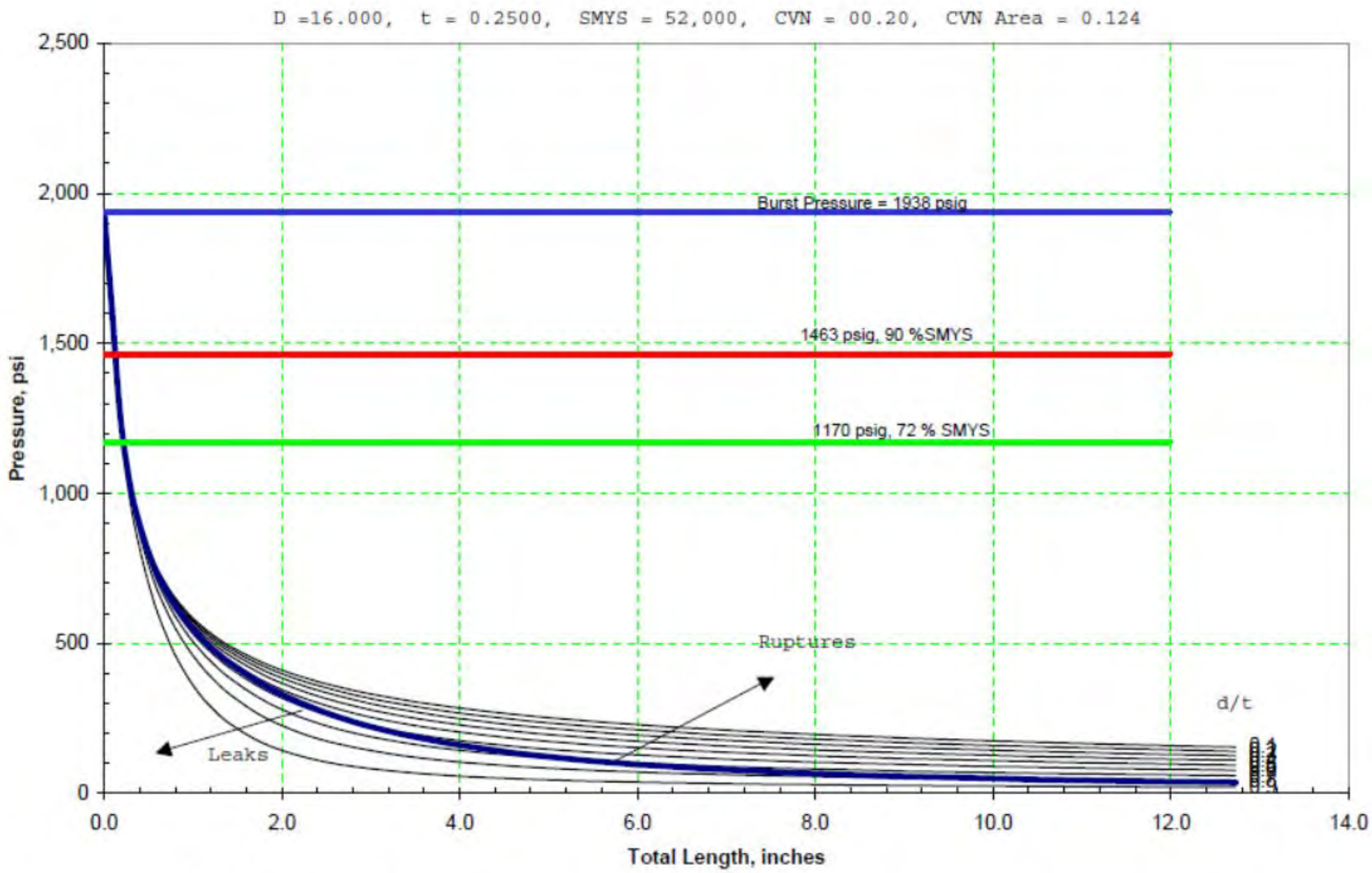

Figure 8.5 Relationship Between Failure Pressure and Flaw Size in Brittle Seams (0.2 ft-lb)

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Baker Report OPS TTO5 REV 3 – API RP 579 Discussion

6.6 API RP579

API Recommended Practice 579 (RP579), Fitness-For-Service, "provides guidance for conducting Fitness-For-Service (FFS) assessments using methodologies specifically prepared for equipment in the refining and petrochemical industry." FSS assessments are "quantitative engineering assessments which are performed to demonstrate the structural integrity of an in-service component containing a flaw or damage." API RP579 is written specifically for ASME and API codes other than B31.4 and B31.8. However, application to pressure containing equipment constructed to other codes is discussed though the referenced appendix for the primary method is still in development.

Several sections of API RP579 are applicable to assessment of flaws or damages of in-service pipelines. In particular, Sections 4, 5, and 6 cover the procedures for assessment of general and local metal loss resulting from corrosion/erosion, mechanical damage, or pitting corrosion. These assessments are geared towards rerating a line by identifying an acceptable reduced MOP and/or coincident temperature. Application of these procedures is applicable in cases where "the original design criteria were in accordance with a recognized code or standard".

Of particular use for review of seam welds is API RP579 Section 9, which provides guidance on assessment of crack-like flaws. This section outlines procedures for conducting Level 1, 2 and 3 assessments. Following these procedures, a Level 1 and a series of Level 2 assessments were completed to develop an acceptable flaw-length versus material-toughness relationship for a hypothetical pipeline. The intent of the exercise was to demonstrate the general method for determining the acceptable conditions for crack-like flaws in pipelines.

Most pipelines under consideration in this report were manufactured prior to 1970 (some date as far back as the 1920's) and a large majority, if not all, of the pipelines manufactured prior to 1950 were made from materials that had a low yield strength (less than 40 ksi). To best simulate these pipelines, the hypothetical pipeline analyses assumed lower strength steel. It was assumed that post weld heat treatment (PWHT) had not been performed and a uniform metal loss, to account for pipe wall reductions that have occurred over time, was included.

The case analyzed considers a crack-like flaw located within the weldment area oriented parallel to the weld seam and detected by inspection. Pipe properties used in the analyses were chosen to resemble realistic conditions of a pipeline similar to those addressed in this report. A summary of the material properties and conditions of the hypothetical pipeline is shown in Table 6.1. These values were held constant throughout the analyses.

Table 6.1 Material Properties & Conditions

Outside Diameter, OD [in]	12.75
Wall Thickness, t_w [in]	0.500
Specified Minimum Yield Strength, SMYS [ksi]	35
Ultimate Tensile Strength, σ_{uts} [ksi]	48
Post Weld Heat Treatment, PWHT	No
Crack Type	Outside Surface
Crack Depth [in]	0.08
Crack Location	Weldment
Crack Orientation	Parallel to Seam
Critical Exposure Temperature, CET [^{o}F]	40
Reference Temperature, T_{ref} [^{o}F]	30
Uniform Metal Loss, LOSS [in]	0.02
Future Corrosion Allowance, FCA [in]	0.0625
Maximum Allowable Operating Pressure, MOP [psi]	1480

A Level 1 assessment follows a series of basic steps and does not take into consideration the pipeline material fracture toughness (a measure of its ability to resist failure by the onset of a crack extension to fracture). Therefore, a Level 1 assessment typically results in a conservative solution. It is also limited to the assessment of materials with SMYS lower than 40 ksi, and is intended for analysis of flaws located away from major structural discontinuities.

Level 2 assessments follow a more rigorous procedure based on more detailed material properties, including material toughness, to produce a more exact solution. Level 2 assessments also account for stress distributions near the cracked region including residual stresses (categorized as secondary stresses) from welding. If actual steel yield strengths are available for the pipeline being assessed, the calculations for residual stresses take this into account. However, if only the minimum yield strength is available an acceptable alternate method for calculating the residual stresses is provided.

Both Level 1 and Level 2 assessments assume that the crack-like flaw is subject to loading conditions and/or an environment that will not result in crack growth and that dynamic loading effects are not significant (i.e. seismic, water hammer, surges, …etc.).

The relationships between critical flaw length and material toughness developed by the Level 1 and Level 2 assessments conducted for the hypothetical pipeline are presented in Figure 6.3. It should be noted that in most cases a pipeline operator will not have performed the type of tests necessary to determine the fracture toughness, KIc, required to perform an assessment according to API 579. Rough correlations do exist between the CVN impact toughness upper shelf absorbed energy, which measures resistance to fracture propagation, and the static fracture initiation toughness, KIc. An understanding of the relationship between fracture initiation and *fracture propagation properties in the temperature domain is also necessary to successfully use these methods.*

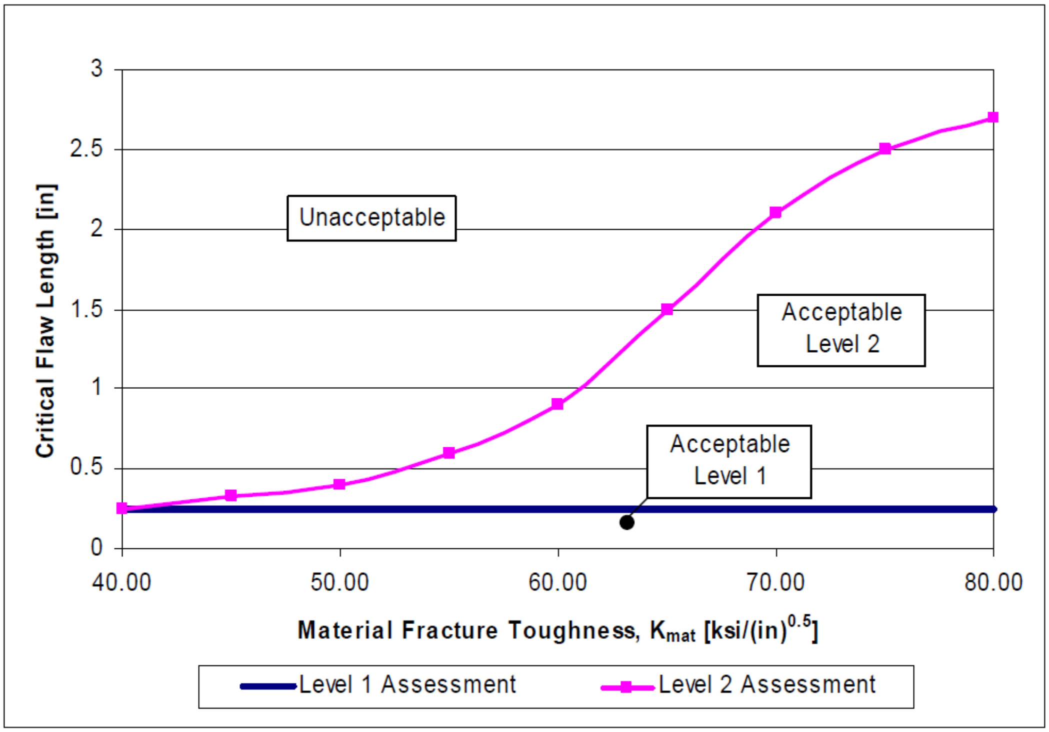

Figure 6.3 Flaw Length versus Material Toughness Relationship

Figure 6.3 clearly shows that since the Level 1 assessment does not consider material fracture toughness, it results in a conservative evaluation of critical flaw length for all cases. However, if the material fracture toughness of material being evaluated can be determined, a Level 2 assessment will potentially reduce the level on conservatism in the analysis by a significant amount.

Though a Level 1 assessment is very conservative, it does not require a significant quantity of detailed material data and can be used to quickly eliminate concerns on many flaws without requiring the rigorous collection of data that may, or may not, exist. However, due to the advent of higher SMYS materials for much of the pipe manufactured after 1950, the Level 1 procedure may not be applicable to pipelines installed more recently.

6.7 Suggested Limitations on the Evaluation of Defects Located in ERW or Lap-welded Seams
It is both necessary and desirable to have techniques for the evaluation of failure stress levels of defects in ERW and lap-welded seams. As indicated above and elsewhere in this document, appropriate equations for this purpose exist. The primary use for such techniques should be limited to predicting the need for seam-integrity assessment and the return interval for re-assessment. These techniques should not be used for evaluating the failure pressures of specific defects in or near LF-ERW, DC-ERW, EFW or furnace lap-welded pipe. It is not prudent to assess specific defects in these materials for two reasons. First and foremost, there is no proven method to determine the effective toughness of a particular piece of pipe without removing it from service. The failure pressures of defects in these materials are highly dependent on the toughness, and the toughness could lie

anywhere within a wide range. While one could assume a conservative lower bound value of toughness, the size of defect that could be safely left would be so small as to make the exercise hardly worthwhile. Secondly, it is particularly difficult to determine the sizes of the types of defects involved (i.e., cracks and grooving corrosion). Therefore, it is strongly recommended that when a pipeline operator discovers and exposes a defect in one of these types of seams, the defective piece of pipe should either be removed or repaired in a manner that relieves the stress on the defect.

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Table of EMPCo Recent pre-70 ERW Failure History

Accident Date	Pipeline Accident Location	Pipe Characteristics	Manufacturer Test/Failure Pressure	Metallurgical Laboratory and Report Number	Reported Cause
12/2/2003	Mendicant Island, Grand Isle to Little Lake Pipeline	High Frequency - ERW API 5L X52 12" x .250"	Republic 1964 1500/1100 psig	Partek Labs, 4/27/2004 Report Hust Labs - Additional Investigation	Manufacturing flaws and corrosion, possible pressure-cycle-fatigue. History of seam leaks, in-service and hydro failure
4/19/2005	Mendicant Island, Grand Isle to Little Lake Pipeline	High Frequency - ERW API 5L X52 12" x .250"	Republic 1964 1500/1155 psig	Metallurgical Consultants, Inc. (MCI) Report 0466-05-16239	Grooving corrosion of ERW seam
6/13/2005	Jefferson Parish, LA Raceland to Anchorage Pipeline	Low Frequency- ERW API 5L Gr B 16" x .312"	Republic 1953 1209 /800 psig	MCI Report 5/9/2006 Report 0067-06-16621	"...angular crack - initiated as a longitudinal crack ~ 5" long, ~ 3/8" from and parallel to the ERW seam. Multiple small cracks on inside surface that joined as they grew to the outside surface." Described as "Very Unusual."
4/28/2012	Torbert, LA Anchorage to Melville East Section of North Line Pipeline	Low Frequency- ERW API 5L X-52 22" x .312"	Youngstown 1956 1334 /969 psig	Element Materials Technology - Report 0283-12-EHO003598P	"Possible pressure-cycle induced fatigue," caused by propagation of "internal hook crack along seam weld" (initiating defect 4" long and 0.11" deep (35% d/t) hook crack)
3/29/2013	Mayflower, AR Pegasus Pipeline	Low Frequency - ERW API 5L X-42 20" x .312"	Youngstown 1947 1082 /708 psig	Hurst Metallurgical Research Laboratory, Inc. Report 64961, Rev. 1	"Hook cracks...manufacturing defects... low fracture toughness of the material in the upset/HAZ" that "merged due to stresses during service."

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