CAL FIRE - Office of the State Fire Marshal Pipeline Safety Division



Pipeline Accident Report: Failure Investigation Report

Lead Investigator Name/Title: Thomas M. Williams IV, Pipeline

Safety Engineer

Supervisor Name/Title: Linda Zigler, Supervising Pipeline Safety Engineer, Chuck MacDonald, Supervising Pipeline Safety Engineer

Activity Report #: 20160520TMW1

Report Date: April 6, 2017 Cal OES Control #: 16-2999

NRC Report #:1148267 and 1148268

OPERATOR, LOCATION, AND CONSEQUENCES

Date of Failure: May 20, 2016

Time Detected: 0035 hours, Pacific Standard Time (PST)

Operator Name: Shell Pipeline Company, LP

CSFM Billing Code: 330

CSFM Inspection Unit #: 0560A

CSFM Pipeline ID #: 0708 (North San Joaquin Valley - Tracy to Ayon)

PHMSA Operator ID: 31174

Leak Location (City/County): Tracy/San Joaquin County

Latitude / Longitude Location:

Pipeline: 20/24 inch "Tracy to Avon" intrastate pipeline

Type of Failure: Seam Failure - weld Commodity Released: Crude Oil

Number of Barrels Released: 500 barrels Number of Barrels Recovered: 400 barrels

Number of Fatalities: None Number of Injuries: None Waterways Impacted: None

Description of Property Damage: Contaminated Soil

Total Costs (Property Damage + Commodity Loss = Estimated Total): \$4,540,000

Thomas M. Williams IV, Pipeline Safety Engineer

Chuck Mac Small 4/6/2017

EXECUTIVE SUMMARY

At 0035 hours (PST) May 20, 2016, the Shell Pipeline Company LP (SPCLP) Control Center located in Houston, Texas detected a drop in the operating pressure on the North San Joaquin Valley (SJV) pipeline system. The Tracy Pump Station automatically shut down on low suction pressure and the SPCLP Houston Control Center Controller immediately shut down the entire SJV pipeline system and isolated the leaking section of pipe by closing the mainline line block valves at Westley, Tracy, Marsh Creek and Avon Pump Stations.

The failure occurred in an open field on the Tracy to Windmills Farm segment of the Tracy Pump Station to Avon Pump Station (CSFM Line ID #0708) pipeline approximately ¾ of a mile north of the Tracy Pump Station located near West Patterson Pass Road and Interstate 580 in Alameda County, California. No waterways were impacted, and no fire, injuries or death occurred because of the spill.

A 79.8-foot section of pipe containing the rupture was cut out and replaced with a new section of pre-hydrostatically pressure tested pipe. A 26-foot long section of pipe containing the rupture was transferred via chain of custody to Det Norske Veritas, Inc. (DNV-GL), a testing laboratory in Dublin, Ohio, for metallurgical examination. A review of the metallurgical examination results in the DNV-GL Laboratory Report Number OAPUS311MPHB (PP158491) issued on November 7, 2016, revealed the pipe ruptured at a fatigue crack that initiated at the toe of the Double Submerged Arc Weld (DSAW) longitudinal seam weld on the inside surface of the pipe. The release occurred on pipe that was originally purchased by Texaco Trading & Transportation Inc. from Columbia Gas and installed by Texaco in 1989.

After repairs were made, the entire pipeline was hydrostatically pressure tested, and the pipeline was reactivated on July 19, 2016.

DESCRIPTION OF THE PIPELINE SYSTEM

The North SJV pipeline system is part of SPCLP's common carrier pipeline system that delivers, heavy, light and blended crude oil from the San Joaquin Valley to San Francisco Bay area refineries. The entire system is approximately 177 miles in length and starts at the SPCLP Coalinga Pump Station and terminates at the SPCLP Martinez Refinery. The entire system was originally constructed by Texaco Trading & Transportation Inc. This system is comprised of the following seven pipeline segments:

- CSFM Line ID #0704 is a 24-inch pipeline originally constructed in 1967 that transports crude oil 6.14 miles from Shell Coalinga Tank Farm to Mack Hill Valve Station.
- CSFM Line ID #0401 is a 20-inch pipeline originally constructed in 1967 that transports crude oil 46.44 miles from Mack Hill Valve Station to Panoche Pump Station.
- CSFM Line ID #0705 is a 20-inch pipeline originally constructed in 1968 that transports crude oil 34.6 miles from Panoche Pump Station to Butts Road Valve Station.
- CSFM Line ID #0707 is a 24-inch pipeline originally constructed in 1967 that transports crude oil 7.07 miles from Butts Road Valve Station to Gustine Pump Station.
- CSFM Line ID #0796 is a 20-inch pipeline originally constructed in 1967 that transports crude oil 42.17 miles from Gustine Pump Station to Tracy Pump Station.
- CSFM Line ID #0708 is a 20/24-inch pipeline originally constructed in 1968 that transports crude oil 38.12 miles from Tracy Pump Station to Avon Pump Station.
- CSFM Line ID #0709 is a 20-inch pipeline originally constructed in 1968 that transports crude oil 2.98 miles from Avon Pump Station to Martinez Refinery.

According to representatives of SPCLP, 12.55 miles of the following segments in the North SJV system have pipe that was purchased from Columbia Gas by Texaco Trading and Transportation. This pipe was manufactured in Houston, Texas by Armco Steel in 1982 and was shipped from Columbia Gas in the northeast United States to Coalinga, California in 1988.

- CSFM Line ID # 0708 3.05 miles of the total 38.12-mile long pipeline.
- CSFM Line ID # 0704 3.4 miles of the total 6.14-mile long pipeline.
- CSFM Line ID # 0707 6.1 miles of the total 7.07-mile long pipeline.

DESCRIPTION OF PIPELINE FAILURE AND INITIAL RESPONSE

A sudden pressure loss was detected by the SPCLP Control Center at 0035 hours (PST) on May 20, 2016. The Tracy Pump Station automatically shut down on low suction pressure and the Houston Controller immediately shutdown the entire North SJV pipeline system. The Controller then isolated the leaking section of pipeline by closing the following motor operated valves (MOV): Westley Valve #001, Tracy Valve #008, Marsh Creek Valves #001 and #008, North 20/24-inch Main Line Block Valves #158 and #169, and the Avon #1 Block Valve. These valves were closed in their pre-planned sequence to prevent any pressure surges. Calculated pressure at the release location at the time of failure was 694 psi. SPCLP notified both the California Office of Emergency Services (Cal OES) and the National Response Center (NRC). CAL FIRE – Office of the State Fire Marshal (OSFM) responded to the release after being notified by Cal OES. The pipeline failure was in a rural area with dry grass on rolling hills. Vacuum trucks were brought in to recover the spilled oil.

At the time of the failure, the pipeline was transporting SJV heavy crude oil. The flowrate was 6,126 barrels per hour (BPH) and the discharge pressure was 694 psi at the Tracy Pump Station. The maximum operating pressure (MOP) was 936 psi.

Representatives of SPCLP and the Oil Spill Response Organizations – Patriot Environmental Services and Ponder Environmental Services – excavated, exposed the pipeline, and recovered the spilled oil. Crude oil had sprayed over an area of approximately 100 feet long by 100 feet wide and had partially soaked into the soil. According to the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) Accident Report Form 7000-1 submitted by SPCLP, approximately 500 barrels of crude oil was released and 400 barrels were recovered.

Excavation of the failed pipe showed that a rupture occurred along the length of the longitudinal seam at the 3:26 o'clock position. The rupture was approximately 3.77 feet in length by 4.5 inches in width, defined as a fish mouth failure. The seam failure was located 14.17-feet and 17.94-feet respectively from the upstream girth weld.

The specifications of the failed pipe section are:

Year Manufactured: 1982 Manufacturer: Armco Steel

Pipe Diameter: 24-inch Outside Diameter

Wall Thickness: 0.260-inch

Specified Minimum Yield Strength: X-60 (60,000 psi)

Pipe Specification: API-5L

Pipe Seam: Double Submerged Arc Weld (DSAW)

Type of Coating: Polyolefin Depth of Cover: 84-inches

REMOVAL OF DEFECTIVE PIPE SECTION

DNV-GL was contracted by SPCLP to perform the metallurgical examination of the failed pipe. At approximately 0300 hours (PST) on May 22, 2016, a 79-foot 8-inch long section of the 24-inch pipe containing the seam failure was cut out and removed. Pipeline Safety Engineers from OSFM were on site to monitor the activities. An estimated 29-foot pipe section that contained the 26.4-foot field joint was wrapped in plastic, mounted and secured on pallets, and stored in a guarded area until it could be transported to the DNV-GL Laboratory in Dublin, Ohio. OSFM staff witnessed the chain of custody process of the failed pipe section from SPCLP to a third-party shipping contractor, Byars Trucking. SPCLP handled the pipe section according to SPCLP's "Handling Instructions for Retrieval of Pipe Section(s) Containing Defects SJV 24-inch Crude Line" procedure, dated September 17, 2015. Representatives of SPCLP followed their Chain of Custody procedures for storing and shipping of the pipe.

PIPELINE REPAIRS

On May 22, 2016, a 79-foot 8-inch long section of pre-hydrostatically tested pipe (CSFM Test ID #16-04897) was installed by Doty Brothers Construction Company of Norwalk, California. The hydrostatic pressure test was conducted by Contra Costa Inspection (CCI), an OSFM approved hydrostatic testing firm.

The specifications for the replacement pipe are:

Manufacturer: CSI Tubular Products, Inc., Fontana, California

Pipe Diameter: 24-inch Outside Diameter

Wall Thickness: 0.375-inch

Specified Minimum Yield Strength: X-65 (65,000 psi)

Pipe Specifications: API-5L

Pipe Seam: Electric Resistance Weld (ERW)

Prior to Doty Brothers' personnel performing the repairs of the pipeline, OSFM Pipeline Safety Engineers verified the Operator Qualification (OQ) records of the following:

- SPCLP Lead Inspector
- Doty Brothers welders
- Applus Non-Destructive Testing Technician.

OSFM Pipeline Safety Engineers observed the welding of the replaced section of 24-inch pipe. The pipeline tie-in welds were non-destructively tested by x-ray and a phased array ultrasonic test, performed by Applus. After the welds were successfully

tested, the tie-in welds were coated with a 3-layer epoxy and were wrapped with Polyken Liquid Adhesive and Polyken tape coating.

On May 23, 2016, after consultation with the OSFM, the North SJV pipeline system was temporarily returned to service at a 20% reduced pressure from 694 psi to 555 psi to displace the heavy crude oil remaining in the line to prevent the crude oil from solidifying in the pipeline. The pipeline temporarily operated at 555 psi, which is a 20% reduced pressure from the 694 psi pressure at the time of the failure. The pipeline system was shut down after the crude oil was displaced. Prior to reactivation of the North SJV pipeline system, SPCLP successfully hydrostatic tested the following segments of the pipeline system that contain the suspected Columbia Gas pipe.

- CSFM Line ID #0708 was hydrostatic tested on June 9, 2016 by Contra Costa Inspection (CSFM Test ID # 16-05004). An 8-hour test was conducted and the minimum test pressure obtained was 1,070 psi.
- CSFM Line ID #0704 was hydrostatic tested on June 17, 2016 by Contra Costa Inspection (CSFM Test ID # 16-05015). An 8-hour test was conducted and the minimum test pressure obtained was 1,070 psi.
- CSFM Line ID #0707 was hydrostatic tested on June 30, 2016 by Contra Costa Inspection (CSFM Test ID# 16-05019). An 8-hour test was conducted and the minimum test pressure obtained was 1,070 psi.

INVESTIGATION DETAILS

The pipeline (CSFM Line ID #0708) experienced the following two previous releases due to seam failure.

- June 6, 1998: (Equilon Pipeline Company) 300 barrels of crude oil was released near Midway Road and I-580. Pipe failed approximately one mile downstream of Tracy Pump Station due to a pipe seam defect. An estimated 40 feet of pipe was replaced (Cal OES Control # 98-0606A).
- September 16, 2015: (Shell Pipeline Company, LP) 900 barrels of crude oil was released at mile post 137, near Tracy, California, on the Coalinga to Avon pipeline. Pipeline ruptured at a pre-existing fatigue crack initiated from small corrosion pits along the internal surface at the toe of the longitudinal seam weld. (Cal OES Control # 15-5483 & NRC #1128732).

A review of the September 16, 2015 pipeline rupture investigation report revealed that on August 6, 2015, TD Williamson (TDW) performed a Magnetic Flux Leak (MFL) and deformation In-Line Inspection (ILI) survey on the pipeline (CSFM Line ID# 0708). The preliminary TDW ILI report issued on September 2, 2015 indicated no immediate conditions were found, as defined by Code of Federal Regulations, Title 49, Part 195.452. Fourteen days later, the pipeline ruptured approximately 1,800 feet

downstream of the Tracy Pump Station. The final TDW ILI report was received by SPCLP on October 14, 2015 and did not identify any metal loss or deformation anomalies at the leak location.

Following the September 16, 2015 release, SPCLP contracted with DNV-GL to perform a metallurgical analysis on the failed section of the pipe. This analysis determined that the pipe section ruptured at a pre-existing fatigue crack on the longitudinal seam. The line was repaired and resumed operation on September 21, 2015. SPCLP initiated a voluntary 20% reduced operating pressure to 724 psi from the previous 905 psi while they investigated the pipeline for similar fatigue crack features. SPCLP decided to use a Rosen Ultrasonic Crack Detection Tool (UT-C) and a Circumferential Magnetic Flux Leak Tool (MFL-C) on the 24-inch pipe in the North SJV pipeline system. The Rosen MFL-C tool was utilized on December 3, 2015 and the UT-C survey was utilized on December 4, 2015.

A preliminary Rosen MFL-C ILI report on January 14, 2016 identified two metal loss anomalies on the Butts Road Valve Station to Gustine Pump Station pipeline (CSFM Line ID # 0707). Type B full encirclement sleeves were used to repair these anomalies. On March 7, 2016, Rosen issued the final MFL-C ILI report that identified an additional 19 anomalies within a 42-foot section of pipe on the Butts Road Pump Station to Gustine Pump Station pipeline (CSFM Line ID # 0707). These anomalies were also repaired using Type B full encirclement sleeves.

On April 11, 2016, the preliminary Rosen UT-C ILI report was received by SPCLP. In the report, five anomalies were identified. Two of these anomalies were on the Tracy Pump Station to Avon Pump Station pipeline (CSFM Line ID # 0708). These anomalies were excavated and no crack indications were found. The anomalies were recoated and the line was backfilled. Two anomalies were identified on the Coalinga to Mack Hill Valve Station pipeline (CSFM Line ID # 0704) requiring an excavation dig. The first anomaly revealed a crack like indication that was repaired with a Type B full encirclement sleeve. The second anomaly identified a metal loss feature and it was repaired and recoated. The last anomaly identified by Rosen was a crack like anomaly on the Butts Road Valve Station to Gustine Pump Station pipeline (CSFM Line ID # 0707). However, upon examination no dents or cracks were found and it was repaired with a Type B full encirclement sleeve.

On May 2, 2016, the final Rosen UT-C ILI report was provided to SPCLP that identified two anomalies that required excavation. One anomaly was a 3-inch flat spot and the other anomaly was a seam weld repair that was done at the pipe mill. Both anomalies were repaired and recoated. Based on the Rosen MFL-C and UT-C results, SPCLP decided to remove the pressure reduction on the 24-inch segments of the North SJV pipeline system. The 20% operating pressure reduction was removed on May 17, 2016

and the pipeline was operating at the normal operating pressure. Three days later, on May 20, 2016, the pipeline (CSFM Line ID# 0708) failed approximately 4,000 feet downstream of the Tracy Pump Station.

Immediately following the release, SPCLP and the OSFM requested that Rosen review and re-evaluate the data from the December 3 and 4, 2015 Rosen ILI surveys. Rosen's review of the ILI data concluded that the survey data did not report any features at the location of the failure.

SPCLP contracted with Kinder Morgan Energy Partners to perform a Kinder Morgan Assessment Protocol (KMAP) review of the Rosen MFL-C ILI data at the failure location. The KMAP is a Kinder Morgan proprietary analytical process that is designed to search for flaws in longitudinal seam welds. The result of the KMAP confirmed that there were no reportable features in the pipe section that failed from the data they received.

SPCLP conducted an internal Root Cause Analysis (RCA) on the May 20, 2016 rupture. According to the RCA, SPCLP found that Rosen's ILI software used to evaluate the Rosen UT-C ILI survey did identify a crack like feature in the longitudinal seam at the failure location. The RCA found that the Rosen ILI software identified the crack as 7.594 inches long and 0.150 inches deep (57.7% of 0.260-inch nominal wall thickness) at odometer reading 4073.718 (rupture location). During the manual review by Rosen analysts, "an incorrect amplitude was selected" and an anomaly depth was calculated at <0.08-inch. Rosen believed that the reporting threshold was 0.08-inch. The Rosen analyst then called the anomaly at 4073.718 (rupture location) as being 0.013-inch. SPCLP's RCA indicates that the Rosen report did not show an anomaly at the rupture location due to this error. As a result, SPLCP resumed operations with normal operating pressure on May 17, 2016.

OSFM contacted Rosen to confirm the data provided in the RCA, however, Rosen only confirmed that they did not report the crack-like anomaly at the position in the failed pipe section.

SPCLP also contracted with DNV-GL to perform a metallurgical analysis on the failed pipe. DNV-GL issued the final report of the metallurgical analysis on November 7, 2016 (Test Report Number OAPUS311MPHB (PP158491)). The examinations DNV-GL performed to determine the metallurgical cause of the failure and to identify any contributing factors included; a visual and photographic examination, dimensional measurements, magnetic particle examination, light microscopy and scanning electron microscopy of the fracture surfaces, cross sections examination, energy dispersive spectroscopy, tensile tests and Charpy V-notch tests, chemical analysis of the steel, and failure pressure calculations.

A review of the final report of metallurgical examination conducted by DNV-GL revealed that:

- The pipe joint ruptured at a fatigue crack initiated at the toe of the DSAW longitudinal seam weld on the inside surface of the pipe.
- A likely contributing factor was a peaked geometry of the failed pipe joint at the seam weld that introduced a bending stress.
- A contributing factor was corrosion micro-pits on the internal diameter surface that provided initiation sites.
- A contributing factor of aggressive pressure cycling of the pipeline.
- Possible environmental effect on crack growth.
- Another possible contributing factor that could not be ruled out was transit fatigue during transportation of the pipe.

DNV-GL conducted the metallurgical examination in accordance with industry accepted standards and used the following American Society for Testing and Materials (ASTM) standards:

- ASTM E7 Standard Terminology Relating to Metallography
- ASTM E3 Standard Methods of Preparation of Metallographic Specimens
- ASTM E8 Test Methods for Tension Testing of Metallic Materials
- ASTM E23 Standard Test Methods for Notched Bar Impact Testing of Metallic Materials
- ASTM A751 -Standard Test Methods, Practices and Terminology for Chemical Analysis of Steel Products.

According to the DNV-GL final report, there was no evidence of external corrosion found. Tensile testing indicated that the pipe met the tensile requirements for American Petroleum Institute (API) 5L Grade X60 pipe. The composition of the base metal of the failed joint and the joints up stream and down stream met the requirements of API-5L Grade X60 pipe.

It should be noted that the DNV-GL report also indicated that the fatigue crack likely occurred while the pipeline was in service, and that transit fatigue during the pipe transportation cannot be ruled out. According to SPLCP transportation records, the pipe was manufactured by Armco Steel in Houston, Texas for Columbia Gas and was shipped to the northeast United States in 1982. In 1988, Texaco purchased the pipe from Columbia Gas and transported it to Coalinga, California for installation and the records for this shipment cannot be located.

American Petroleum Institute Recommended Practice 5L1, "Recommended Practice for Railroad Transportation of Line Pipe," 7th edition, September 2009, (API RP 5L1) is used to assure that pipe is properly loaded and transported to avoid transit fatigue. API RP 5L1 also states that pipe with a diameter to wall thickness ratio greater than 50 is

susceptible to transit fatigue. The failed pipe had a ratio of 92 (24-inch/0.260-inch wall thickness).

INVESTIGATION FINDINGS

- The OSFM concluded that the primary cause of the May 20, 2016 release was a fatigue crack that initiated at the toe of the longitudinal seam weld on the inside surface of the pipe (CSFM Line ID #0708) that developed and grew through continuous pressure cycling.
- The May 2, 2016, Rosen UT-C ILI report failed to identify the crack like feature in the longitudinal seam of the pipe.
- It is possible that transit fatigue may have occurred during transportation of the pipe in 1988.

RECOMMENDATIONS

- 1. Effective immediately, the Tracy Pump Station to Avon Pump Station pipeline (CSFM Line ID# 0708) shall be placed on the State Fire Marshal's list of higher risk pipelines as required by Government Code Section 51013.5 (f)(1). SPCLP will be required to either perform in-line inspections or hydrostatic tests every two years. The pipeline will be removed from this list after May 20, 2021, if there are no more leaks due to corrosion or manufacturing defects during this time.
- 2. SPCLP shall replace the entire sections of the pipeline that contain "Columbia Pipe". These sections are the 3.05 miles of the total 38.12-mile long pipeline from Tracy Pump Station to Avon Pump Station (CSFM Line ID # 0708), 3.4 miles of the 6.14-mile long pipeline from Coalinga Pump Station to Mack Hill Valve Station (CSFM Line ID # 0704), and 6.1 miles of the 7.07-mile long pipeline from Butts Road Valve Station to Gustine Pump Station (CSFM Line ID # 0707).
- 3. SPCLP shall require all ILI vendors to immediately notify SPCLP personnel of any raw data that is excluded from all future reports. SPCLP should also review their process for conducting crack detection surveys for all seam types of pipe DSAW, ERW, etc.
- 4. SPCLP shall review and evaluate their pipelines that undergo aggressive pressure cycling to determine if additional crack detection surveys should be conducted on these pipelines and to determine if pressure cycling can be minimized.
- 5. The OSFM Pipeline Safety Division shall conduct a comprehensive and in-depth Headquarters review of SPCLP's Integrity Management Program. This inspection will be conducted the week of September 25, 2017.

Photo Log of Spill - Operator: Shell Pipeline Company L.P. - Tracy Windmill Farms Spill Date: May 20, 2016.



Photograph #1

Description of Photograph:

Photo taken by Pipeline Safety **Engineer Thomas Williams on** the morning of May 20, 2016 This is an overview of the San Joaquin Valley 20/24" Heavy Crude Oil (CSFM #0708) spill site (Tracy Windmill Farms looking South.)



Photograph #2

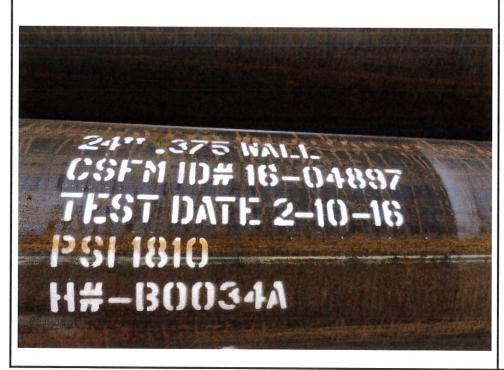
Description of Photograph:

Photo taken by Pipeline Safety Engineer Thomas Williams on May 20, 2016. This is another overview of the spill on The San Joaquin Valley 20/24" Heavy Crude Oil (CSFM #0708) Tracy Windmill Farms looking North.



Photograph #3

Description of Photograph: Photo taken by Pipeline Safety Engineer Thomas Williams on the morning of May 21, 2016. This is a view of the rupture on The San Joaquin Valley 20/24" Heavy Crude Oil (CSFM #0708)



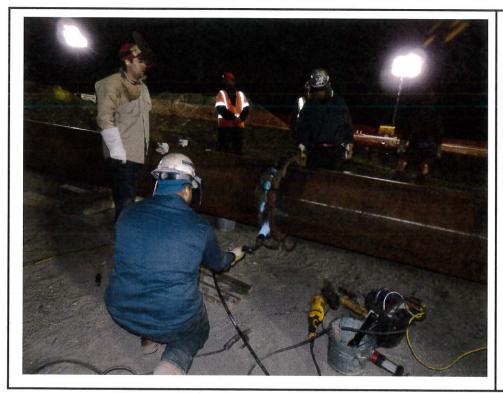
Photograph #4

Description of Photograph: This is a picture of the CSFM Pre-hydrotested pipe information Photo taken by Pipeline Safety Engineer Thomas Williams on the morning of May 21, 2016.



Photograph #5

Description of Photograph:
Photo taken by Pipeline Safety
Engineer Thomas Williams on
May 22, 2016.
This is a photo of Doty
Brothers Construction
Company cutting out the failed
section of pipe to send to Lab.



Photograph #6

Description of Photograph:
Photo taken by Pipeline
Safety Engineer Thomas
Williams on the early morning
of May 22, 2016. This is a
photo of Doty Brothers
Construction Company weld
the new section of pipe.



Photograph #6

Description of Photograph:
Photo taken by Pipeline Safety
Engineer Thomas Williams on
the early morning of May 22,
2016. This is a photo of
ApplusRTD technicians
shooting x-rays on the welds
on CSFM #0708



Photograph #6

Description of Photograph:
Photo taken by Pipeline Safety
Engineer Thomas Williams on
May 22, 2016. This is a photo
of ApplusRTD technicians
using Phased Array

Governor's Office Emergency Services Hazardous Materials Spill Report

	Hazar	dous IVI	aterials !	Spill R	eport		
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Photo Attachment:		,	
	******* Co	ontrol No: 16-2999 *******	*

Created by: Warning Center on: 05/20/2016 02:21:27 AM Last Modified by: Warning Center on: 05/20/2016 02:49:58 AM



Governor's Office of Emergency Services Hazardous Material Spill Update

CONTROL#: 16-2999 NRC# 1148267

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			UNIFIED AP	CD
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AGENCY: Shell Pipeline				
1.b. PERSON REPORTING	SPILL (If differe	ent from above):		
AGENCY:				
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a. SUBSTANCE: b. QTY: Measu Amount	c. TYPE	d. OTHER	e. PIPEL	INE f. VESSEL
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Per the NRC Report: "THE SCADA SYSTEM NOTICED A COMPLETE LOSS OF PRESSURE ON A 24" PIPELINE. THE LINE WAS SHUT-DOWN AND COULD HAVE POTENTIALLY DISCHARGED PETROLEUM CRUDE. BELOW GROUND PIPELINE. REMEDIAL ACTIONS *

CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED * LINE IS DOWN, VALVES ARE CLOSED."

FAX NOTIFICATION LIST:

AA/CUPA, DFG-OSPR, DTSC, RWQCB, US EPA, USFWS, COASTAL COM, CDPH-D.O., DWP-DO, DOG, EB PARKS, LANDS, PARKS & REC, SFM, USCG, Co/WP, Co/Hlth, Co/E-Hlth

ADMINISTERING

San Joaquin County Environmental Health

AGENCY:

SECONDARY AGENCY:

ADDITIONAL COUNTIES: Alameda County, Contra Costa County

ADDITIONAL ADMIN.

Alameda County Environmental Health, Contra Costa County Health Services

AGENCY:

Department

OTHER NOTIFIED:

RWQCB Unit:

5B

CONFIRMATION REQUEST:

FAX NOTIFICATION

LIST:

ADMINISTERING

AGENCY:

ADDITIONAL ADMIN.

AGENCY:

SECONDARY AGENCY:

ADDITIONAL

COUNTIES:

DOG Unit:

RWQCB Unit:

Created by: Warning Center on: 05/20/2016 03:04:37 AM Last Modified by: Warning Center on: 05/20/2016 03:11:09 AM

********** End of Form *********



Governor's Office of Emergency Services Hazardous Material Spill Update

CONTROL#: 16-2999 NRC#

NOTIFY DATE/TIME: 05/20/2016 / 0221	OCCURENCE DATE/TIME:	CITY/OP. AREA: Tracy/San Joaquin County
	II -	SAN JOAQUIN VALLEY UNIFIED APCD

1.a. PERSON NOTIFYING Cal OES:

AGENCY: Shell Pipeline	20000	\$ 2°	

1.b. PERSON REPORTING SPILL (If different from above):

AGENCY:		

SUBSTANCE TYPE:

a. SUBSTANCE:	b. QTY:	Measure	c. TYPE:	d. OTHER:	e. PIPELINE	Ef. VESSEL
	Amount					>=300 Tons
1.Crude Oil	Unknown	Bbl.(s)	PETROLEUM		Yes	No
2.					No	No
3.					No	No

Orignal Description: POTENTIAL RELEASE RP States: Drop in pressure in the pipeline that connects from Martinez to Coalinga, possibly in the Tracy area per his supervisor. Unknown on any release, though pressure would indicate that a release is occurring somewhere on the line. The line has been isolated, shutdown from Houston, Texas.

Update(s): 05/20/2016 03:04:37 AM - Per the NRC Report: "THE SCADA SYSTEM NOTICED A COMPLETE LOSS OF PRESSURE ON A 24" PIPELINE. THE LINE WAS SHUT-DOWN AND COULD HAVE POTENTIALLY DISCHARGED PETROLEUM CRUDE. BELOW GROUND PIPELINE. REMEDIAL ACTIONS * CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED * LINE IS DOWN, VALVES ARE CLOSED."

; 05/20/2016 04:03:39 AM - RP States: No waterways impacted. Location: .75 miles NNW of West Patterson Past Road and I 580 in San Joaquin County. 500 barrels is equivalent to 21,000 gallons of crude oil released.

Shell Pipeline

PERSON NOTIFYING Cal OES OF SPILL UPDATE:

NAME:

AGENCY: PHONE#: Ext:

PAG/CELL:

UPDATE

Measure

QUANTITY

Amount

Bbl.(s) 1.500

2.

3.

4.

UPDATE KNOWN IMPACT:	
UPDATE CAUSE:	

SITUATION UPDATE:

RP States: No waterways impacted. Location: .75 miles NNW of West Patterson Past Road and I 580 in San Joaquin County. 500 barrels is equivalent to 21,000 gallons of crude oil released.

FAX NOTIFICATION LIST:

AA/CUPA, DFG-OSPR, DTSC, RWQCB, US EPA, USFWS, COASTAL COM, CDPH-D.O., DWP-DO, DOG, EB PARKS, LANDS, PARKS & REC, SFM, USCG, Co/WP, Co/Hlth, Co/E-Hlth

ADMINISTERING

San Joaquin County Environmental Health

AGENCY:

SECONDARY AGENCY:

ADDITIONAL COUNTIES: A

Alameda County, Contra Costa County

ADDITIONAL ADMIN.

Alameda County Environmental Health, Contra Costa County Health Services

AGENCY:

Department

OTHER NOTIFIED:

RWQCB Unit:

5B

CONFIRMATION REQUEST: Please confirm receipt via email or call 916-845-8911.

FAX NOTIFICATION

LIST:

ADMINISTERING

AGENCY:

ADDITIONAL ADMIN.

AGENCY:

SECONDARY AGENCY:

ADDITIONAL

COUNTIES:

DOG Unit:

RWQCB Unit:

Created by: Warning Center on: 05/20/2016 04:03:39 AM Last Modified by: Warning Center on: 05/20/2016 04:24:40

AM

******** End of Form *********

PrevDoc NextDoc

ATTACHMENT 41

Governor's Office of Emergency Services Hazardous Material Spill Update

CONTROL#: 16-2999 NRC#

NOTIFY DATE/TIME:
05/20/2016 / 0221

RECEIVED BY:
0CCURENCE DATE/TIME:
05/20/2016/0205

CITY/OP. AREA:
Tracy/San Joaquin County

SAN JOAQUIN VALLEY
UNIFIED APCD

1.a. PERSON NOTIFYING Cal OES:

AGENCY: Shell Pipeline

1.b. PERSON REPORTING SPILL (If different from above):

AGENCY:

3.

SUBSTANCE TYPE:

a. SUBSTANCE: b. QTY: Measure Amount c. TYPE: d. OTHER: e. PIPELINE f. VESSEL >= 300 Tons

1. Crude Oil Unknown Bbl.(s) PETROLEUM Yes No No No No

Orignal Description: POTENTIAL RELEASE RP States: Drop in pressure in the pipeline that connects from Martinez to Coalinga, possibly in the Tracy area per his supervisor. Unknown on any release, though pressure would indicate that a release is occurring somewhere on the line. The line has been isolated, shutdown from Houston, Texas.

Update(s): 05/20/2016 03:04:37 AM - Per the NRC Report: "THE SCADA SYSTEM NOTICED A COMPLETE LOSS OF PRESSURE ON A 24" PIPELINE. THE LINE WAS SHUT-DOWN AND COULD HAVE POTENTIALLY DISCHARGED PETROLEUM CRUDE. BELOW GROUND PIPELINE. REMEDIAL ACTIONS * CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED * LINE IS DOWN, VALVES ARE CLOSED."

; 05/20/2016 04:03:39 AM - RP States: No waterways impacted. Location: .75 miles NNW of West Patterson Past Road and I 580 in San Joaquin County. 500 barrels is equivalent to 21,000 gallons of crude oil released.

; 05/20/2016 04:24:53 AM - Per NRC Report"ACCORDING TO THE REPORTING PARTY THERE IS A DISCHARGE OF 500 BARRELS OF CRUDE OIL ONTO THE GROUND. NO WATERWAYS IMPACTED. REMEDIAL ACTIONS * CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED * LINE IS DOWN, VALVES ARE CLOSED. ACCORDING TO THE REPORTING PARTY THERE IS A DISCHARGE OF 500 BARRELS OF CRUDE OIL ONTO THE GROUND. NO WATERWAYS IMPACTED. THE NEW NRC REPORT NUMBER IS 1148268.

; 05/21/2016 02:40:43 PM - Per RP the spill is in Alameda County

PERSON NOTIFYING Cal OES OF SPILL UPDATE:

NAME:

AGENCY:

PHONE#:

Ext:

No

No

PAG/CELL:

Shell Pipeline

Measure

UPDATE

QUANTITY

Amount

1.

Bbl.(s)

2.

3.

3. 4.

UPDATE KNOWN IMPACT:	
UPDATE CAUSE:	

SITUATION UPDATE:

Per RP the spill is in Alameda County

FAX NOTIFICATION LIST:

AA/CUPA, DFG-OSPR, DTSC, RWQCB, US EPA, USFWS, COASTAL COM, CDPH-D.O., DWP-DO, DOG, EB PARKS, LANDS, PARKS & REC, SFM, USCG, Co/WP, Co/Hlth, Co/E-Hlth

ADMINISTERING AGENCY:

San Joaquin County Environmental Health

SECONDARY AGENCY: ADDITIONAL COUNTIES:

Alameda County, Contra Costa County

ADDITIONAL ADMIN.

Alameda County Environmental Health, Contra Costa County Health Services Department

AGENCY:

OTHER NOTIFIED:

RWQCB Unit:

5B

CONFIRMATION REQUEST:

FAX NOTIFICATION

LIST:

ADMINISTERING

AGENCY:

ADDITIONAL ADMIN.

AGENCY:

SECONDARY AGENCY:

ADDITIONAL

COUNTIES:

DOG Unit:

RWQCB Unit:



Governor's Office of Emergency Services Hazardous Material Spill Update

CONTROL#: 16-2999 NRC#

NOTIFY DATE/TIME:	RECEIVED BY:	CITY/OP. AREA:
05/20/2016 / 0221	OCCURENCE DATE/TIME:	Tracy/San Joaquin County
	05/20/2016/0205	
	11	SAN JOAQUIN VALLEY
		UNIFIED APCD

1.a. PERSON NOTIFYING Cal OES:

AGENCY: Shell Pipeline	
------------------------	--

1.b. PERSON REPORTING SPILL (If different from above):

AGENCY:	

SUBSTANCE TYPE:

a. SUBSTANCE:	b. QTY: Measure	c. TYPE:	d. OTHER:	e. PIPELINE	f. VESSEL
	Amount				>= 300 Tons
1.Crude Oil	Unknown Bbl.(s)	PETROLEUM		Yes	No
2.				No	No
3.				No	No

Orignal Description: POTENTIAL RELEASE RP States: Drop in pressure in the pipeline that connects from Martinez to Coalinga, possibly in the Tracy area per his supervisor. Unknown on any release, though pressure would indicate that a release is occurring somewhere on the line. The line has been isolated, shutdown from Houston, Texas.

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; 05/21/2016 02:40:43 PM - Per RP the spill is in Alameda County

PERSON NOTIFYING Cal OES OF SPILL UPDATE: PAG/CELL: **AGENCY:** PHONE#: Ext: NAME: Shell Pipeline Measure **UPDATE QUANTITY** Amount 1. Bbl.(s) 2. 3. 4. UPDATE KNOWN **IMPACT: UPDATE CAUSE:** SITUATION UPDATE: Per RP the spill is in Alameda County **FAX NOTIFICATION LIST:** AA/CUPA, DFG-OSPR, DTSC, RWQCB, US EPA, USFWS, COASTAL COM, CDPH-D.O., DWP-DO, DOG, EB PARKS, LANDS, PARKS & REC, SFM, USCG, Co/WP, Co/Hlth, Co/E-Hlth San Joaquin County Environmental Health **ADMINISTERING** AGENCY: SECONDARY AGENCY: Alameda County, Contra Costa County ADDITIONAL COUNTIES: Alameda County Environmental Health, Contra Costa County Health Services ADDITIONAL ADMIN. AGENCY: Department OTHER NOTIFIED: 5B **RWQCB** Unit: **CONFIRMATION REQUEST: FAX NOTIFICATION** LIST: **ADMINISTERING AGENCY:** ADDITIONAL ADMIN. AGENCY: **SECONDARY AGENCY:**

ADDITIONAL

COUNTIES:

DOG Unit:

RWQCB Unit:

FW: NRC#1148267: Pipeline - Tracy, CA (55 miles E of San Francisco, CA), unknown amount of crude oil spill

Katchmar, Peter (PHMSA) [Peter.Katchmar@dot.gov]

Sent: Wednesday, December 21, 2016 8:37 AM

To: MacDonald, Chuck@CALFIRE

Thank you,

Peter Katchmar

Western Region, PHMSA Accident Coordinator





From: Katchmar, Peter (PHMSA) Sent: Friday, May 20, 2016 4:33 AM

To: State-CSFM-Bob Gorham <Bob.Gorham@fire.ca.gov>; State-CSFM-Doug Allen <Doug.Allen@fire.ca.gov>;

State-CSFM-Linda Zigler < Linda. Zigler@fire.ca.gov>

Cc: PHMSA PHP500 Response < PHMSAPHP500Response@dot.gov>

Subject: FW: NRC#1148267: Pipeline - Tracy, CA (55 miles E of San Francisco, CA), unknown amount of crude oil

spill

Please provide a report on this event when possible.

Thank you, Peter J. Katchmar

Sent with Good (www.good.com)

From: CMC-01 (OST)

Sent: Friday, May 20, 2016 4:11:52 AM

To: PHMSA PHP80 Response; PHMSA PHP500 Response

Subject: NRC#1148267: Pipeline - Tracy, CA (55 miles E of San Francisco, CA), unknown amount of crude oil spill

This report is forwarded for your situational awareness. CMC 6-1863

NATIONAL RESPONSE CENTER 1-800-424-8802
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***

Information released to a third party shall comply with any applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1148267

INCIDENT DESCRIPTION

**** THIS IS A POTENTIAL RELEASE ****

*Report taken by: CIV ANTONAY GREER at 05:44 on 20-MAY-16

Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area: UNKNOWN

Incident occurred on 20-MAY-16 at 02:05 local incident time.

Affected Medium: UNKNOWN *** POTENTIAL POLLUTION***

REPORTING PARTY

Name: ROBERT MARSHALL Organization: SHELL PIPELINE

Organization: SHELL PIPELINE Address: 1801 PETROL RD

BAKERSFIELD, CA 93308

PRIMARY Phone: (661)9795275

Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY

Name: N/A

Organization: SHELL PIPELINE Address: 1801 PETROL RD

BAKERSFIELD, CA 93308

PRIMARY Phone: (661)9795275

INCIDENT LOCATION

County: ALAMEDA City: TRACY State: CA

BETWEEN ALAMEDA AND SAN JUAQIN COUNTIES

*NO POSITION OR LEGALS PROVIDED

POTENTIALLY RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE

Also Known As:

Qty Released: 0 UNKNOWN AMOUNT Qty in Water: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

THE SCADA SYSTEM NOTICED A COMPLETE LOSS OF PRESSURE ON A 24" PIPELINE. THE LINE WAS SHUT-DOWN AND COULD HAVE POTENTIALLY DISCHARGED PETROLEUM CRUDE.

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: FLOW DOT Regulated: YES

Pipeline Above/Below Ground: BELOW

Exposed or Under Water: NO Pipeline Covered: UNKNOWN ---WATER INFORMATION---Body of Water: UNKNOWN

Tributary of:

Nearest River Mile Marker:

Water Supply Contaminated: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

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

Damages: NO

Hours Direction of

Closure Type Description of Closure Closure

N

Air:

N

Major

Road:

Artery:N

Ν

Waterway:

Ν

Track:

Environmental Impact: UNKNOWN

Media Interest: UNKNOWN Community Impact due to Material:

REMEDIAL ACTIONS

- * CREWS ENROUTE FOR ASSESSMENT, OSRO'S NOTIFIED
- * LINE IS DOWN, VALVES ARE CLOSED.

Release Secured: UNKNOWN

Release Rate:

Estimated Release Duration:

WEATHER

Weather: UNKNOWN, °F

ADDITIONAL AGENCIES NOTIFIED

Federal:

State/Local: CA-OES State/Local On Scene:

State Agency Number: 16-2999

NOTIFICATIONS BY NRC

CA U.S. ATTORNEY'S OFFICE NORTH (MAIN OFFICE)

20-MAY-16 05:56 (415)4367077

CA DEPT OF FISH AND GAME (OFFICE OF SPILL PREVENTION AND RESPONSE)

20-MAY-16 05:56 (916)

CENTERS FOR DISEASE CONTROL (GRASP)

20-MAY-16 05:56 (770)4887100

CONTRA COSTA OFC OF SHERIFF (HOMELAND SECURITY UNIT)

20-MAY-16 05:56 (925)3139612

DHS PROTECTIVE SECURITY ADVISOR (PSA DESK)

20-MAY-16 05:56 (703)2355724

DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)

20-MAY-16 05:56 (202)3661863

U.S. EPA IX (MAIN OFFICE)

(415)2279500

FEMA REGION 09 (SITUATION AWARENESS UNIT)

20-MAY-16 05:56 (510)6277802

NORTHERN CA REG INTELLIGENCE CENTER (COMMAND CENTER SAN FRANCISCO)

20-MAY-16 05:56 (415)5752788

NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)

20-MAY-16 05:56 (202)2829201

NOAA RPTS FOR CA (MAIN OFFICE)

20-MAY-16 05:56 (206)5264911

NATIONAL RESPONSE CENTER HQ (AUTOMATIC REPORTS)

20-MAY-16 05:56 (202)2671136

NTSB PIPELINE (MAIN OFFICE)

20-MAY-16 05:56 (202)3146293

PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))

20-MAY-16 05:56 (202)3660568

SECTOR SAN FRANCISCO (MAIN OFFICE)

(415)3993547

CA STATE EMERGENCY SERVICES (MAIN OFFICE)

20-MAY-16 05:56 (916)2621621

STATE TERRORISM & THREAT ASSESS CTR (COMMAND CENTER SACRAMENTO)

20-MAY-16 05:56 (916)8741100

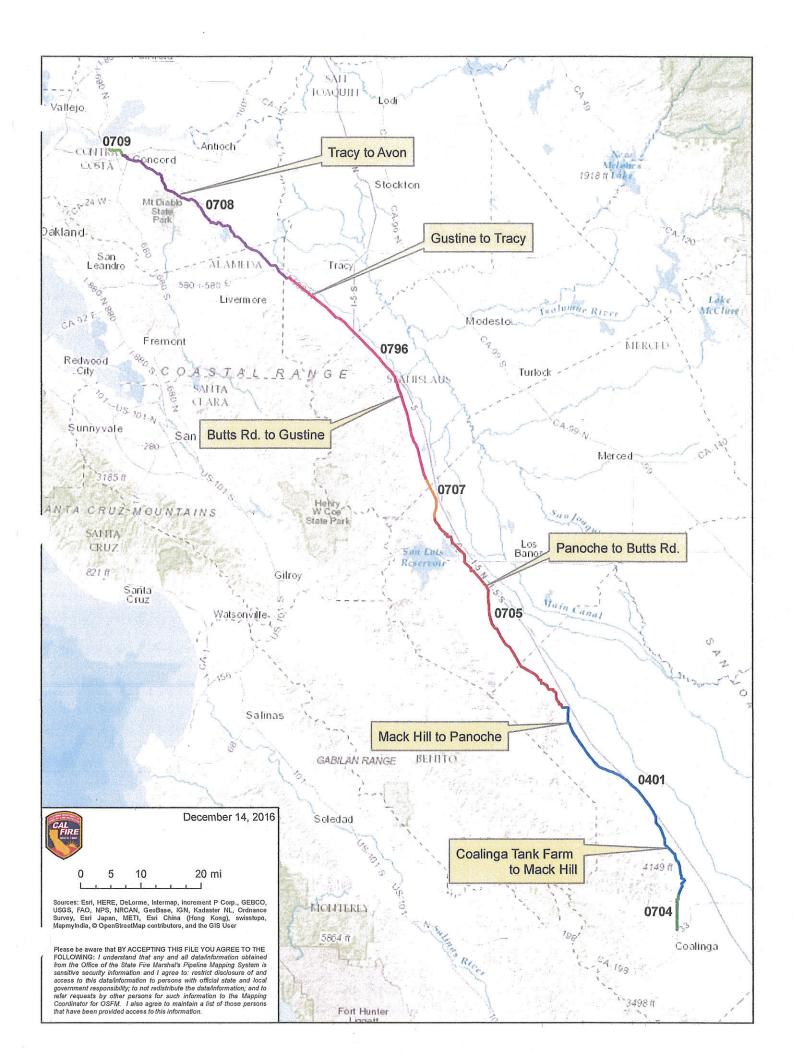
ADDITIONAL INFORMATION

*** END INCIDENT REPORT #1148267 ***

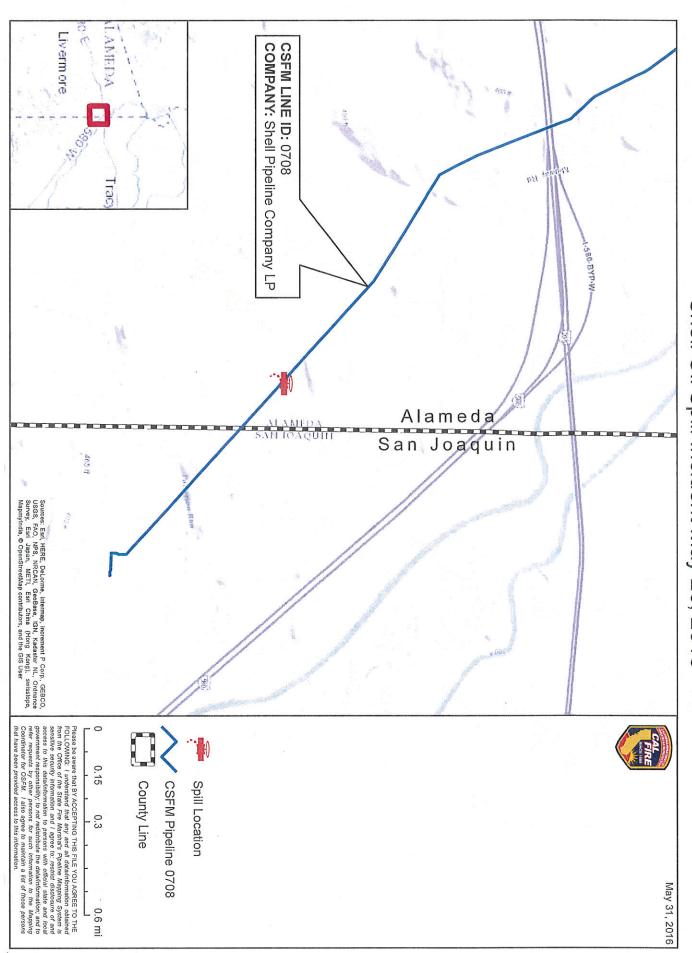
Report any problems by calling 1-800-424-8802

PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil

The information contained in this communication from the Department of Transportation's Crisis Management Center (CMC) Watch may be sensitive or privileged and is intended for the sole use of persons or entities named. If you are not an intended recipient of this transmission, you are prohibited from disseminating, distributing, copying or using the information. If you have received this communication in error, please immediately contact the CMC Watch at (202) 366-1863 to arrange for the return of this information.



Shell Oil Spill Incident May 20, 2016



on: Tracy, California (al Released: Crude oil A Arrival Time & Date: 1 PM/ May 2	20, 2016 PHM Company Pipe – Fat	igue crack	Sence: May 20, 500 barrels Sent Sent Sent Sent Sent Sent Sent Sent	, 2016	20160520TMW1
A Arrival Time & Date: 1 PM/ May 2 gation Responsibility: X State bany Reported Apparent Cause: orrosion fatural Force Damage excavation Damage ther Outside Force Damage Interial Failure (Pipe, Joint, Weld) quipment Failure accorrect Operation other ther dent/Incident Resulted in (check all upture	PHM Company Pipe – Fat	Quantity:Total Damages ISANTSE Preported Sub-Control igue crack	500 barrels \$: \$4,540,000 Other Cause (from PHMS)		000-1/7100.2
A Arrival Time & Date: 1 PM/ May 2 gation Responsibility: X State bany Reported Apparent Cause: orrosion fatural Force Damage excavation Damage ther Outside Force Damage Interial Failure (Pipe, Joint, Weld) quipment Failure accorrect Operation other ther dent/Incident Resulted in (check all upture	PHM Company Pipe – Fat	Quantity:Total Damages ISANTSE Preported Sub-Control igue crack	500 barrels \$: \$4,540,000 Other Cause (from PHMS)		000-1/7100.2
A Arrival Time & Date: 1 PM/ May 2 gation Responsibility: X State Dany Reported Apparent Cause: 1 PM/ May 2 Dany	PHM Company Pipe – Fat	Total Damages SA NTSE Reported Sub-C	\$: _\$4,540,000 B _Other Cause (from PHMS)		000-1/7100.2
gation Responsibility: X State conny Reported Apparent Cause: corrosion fatural Force Damage excavation Damage other Outside Force Damage faterial Failure (Pipe, Joint, Weld) quipment Failure facorrect Operation other lent/Incident Resulted in (check all upture	PHM Company Pipe – Fat	SA NTSE	Other		000-1/7100.2
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orrosion fatural Force Damage excavation Damage other Outside Force Damage faterial Failure (Pipe, Joint, Weld) quipment Failure facorrect Operation other faterial Failure facorrect Operation other	Pipe – Fat	igue crack		SA Form 70	000-1/7100.2
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upture	that apply)): Commen	rks:		
xplosion		Number o	f Persons:	Area:	
vacuation		Number o	r Persons:	Area:	
	Narra	tive Summary			
ummers of the Incident/Accident scenario					
ing pressure on the North San Joaquin station immediately shut down on love system and immediately isolated the ed in an open field approximately ¾ out of ire, injuries or death occurred ed. Metallurgical examination of the field.	n Valley 24 w suction pre e leaking see of a mile down l. A 79.8' see ailed pipe w	"Tracy to Avon or ressure and the continuous of pipe by claim of the Totion of pipe continuous conducted by	crude oil pipeline (Control center immed losing the main line Gracy pump station. aining the seam fail Det Norske Veritas	CSFM #0708 diately shut of block valves . No waterwa lure was cut s of Dublin, O	i). The Tracy down the enti s. The failure ays were out and Ohio. After
tate: Western - California Investigator: Thomas M. Williams	s IV	_ Review _ Title:	ved by: Charle Supu Pl Si	Me Dm	11 ineer
	mmary of the Incident/Accident scenario 5 hours (PST) May 20, 2016, Shell Pining pressure on the North San Joaqui station immediately shut down on love system and immediately isolated the din an open field approximately % oed, no fire, injuries or death occurred ed. Metallurgical examination of the factories were made, the entire line was hydroate: Western - California	mmary of the Incident/Accident scenario 5 hours (PST) May 20, 2016, Shell Pipeline Compang pressure on the North San Joaquin Valley 24 station immediately shut down on low suction presystem and immediately isolated the leaking seed in an open field approximately 3/4 of a mile down on fire, injuries or death occurred. A 79.8' seed. Metallurgical examination of the failed pipe we were made, the entire line was hydrostatically to the seed of the seed of the entire line was hydrostatically to the seed of the seed of the entire line was hydrostatically to the seed of the seed of the entire line was hydrostatically to the seed of the seed of the entire line was hydrostatically to the seed of the se	Number of Number	Number of Persons: Number of Persons:	Number of Persons: Area:

Patture Loca	ion & Response					
Location (City, Township, Range, (Acquire Map)						
County/Parish): Outside of Tracy, Alameda County, California						
	(2)		40			
Address or M.P. on Pipeline:	(I) Type of Area (R	tural, City):	(1)			
MP 136.7	Rural					
Coordinates of failure location (Latitude):	(Long	gitude):				
Date: May 20, 2016	Time of Failure:	: 0035 PST				
Time Detected: 0035 PST	Time Detected: 0035 PST Time Located: 0217 PST					
How Located: Ground Patrol						
NRC Report #: 1148267 Time Reported to N	C: 0244 PST 5/20/16	6	Reported by: Bob Marshall, Shell Pipeline Company			
Type of Pipeline:						
Gas Distribution Gas Transm	ssion H:	azardous Liqu	uid LNG			
LP · Interstate C	as	Interstate Liqu	uid			
Municipal Intrastate 0	as X Intrastate Liquid					
Public Utility Gas Gather	Offshore Liquid					
Master Meter Offshore Gas Liquid Gathering						
Offshore Gas - High H ₂ S CO ₂						
		Low Stress Li HVL	quid			
Pipeline Configuration (Regulator Station, Pump Station, Pipe						
24" Pipeline from Tracy Station to Windmill Farms CSFM 1	0708					
Operator/Ov	ner Information					
Owner: San Pablo Bay Operator: Shell Pipeline Company LP						
Address: 910 Louisiana Street	Address: 910 Louisiana Street					
Houston, Texas 77002 Houston, Texas 77002						
Company Official: Greg Smith, President Company Official: Greg Smith, President						
Phone No.: Fax No.: N/A Phone No. Fax No. N/A						
Drug and Alcohol Testing Program Contacts X N/A						
Drug Program Contact & Phone: Michael Courville, Operation						
Alcohol Program Contact & Phone: Michael Courville, Opera	ions Support Specialis	st, 713-241-074	40			

1 Photo documentation

	A STATE		D	amages						
Product/Gas Loss or Spill ⁽²⁾ 500 barrels	The same of the same of	y and the second of the second	100000000000000000000000000000000000000	Estir \$25,	nated Prop	erty Da	amage);	The state of the s	
Amount Recovered 400 barrels				Associated Damages (3) \$2,930,000						
Description of Property Dama	.ca. &	05 AAA in maana		ras \$1.22	o on in a	manata	**************	onavtu da	HALLONG CHAIL TONGS	
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atalities:		Yes	No	Compa	ny:	ny: Contract		actor:	Public:	
njuries - Hospitalization:		Yes	No	Compa	ny:	Contractor:		actor:	Public:	
njuries - Non-Hospitalization	1 :	Yes	No	Compa	ny:		Contractor:		Public:	
otal Injuries (including Non-	-Hospit	alization):		Compa	ny:	Contractor:		actor:	Public:	
Name		Job Function			Yrs. w/ Comp.	Yrs. Exp.			Type of Injury	
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			Dri	e/Alcoh	ol Testing				The second se	
Vere all employees that could			Comments to the	1000 (Barrier A. 1997)	· · · · · · · · · · · · · · · · · · ·	的 是有情况的	hin th	e 2-hour	THE RESERVE AND A SECOND PROPERTY OF THE PARTY OF THE PAR	
ne 32-hour time frame for all	other o	lrugs?			•					
_YesNo	<u> </u>							4.		
Job Function	Test	Date & Time	Locat	Location			sults	Type of Drug		
 					- to the second		Pos	Neg		
			<u> </u>		1			<u>.</u>		
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			Cheran	ı Descri		***				
escribe the Operator's Syst Il from the San Joaquin Va			North 20	, Coaling	a to Avon		inch j	pipeline s	system. Transports Crud	
Programme and the second			2004	ure Des	CLASSON AS ALL				N/	
ength of Failure (inches, fee	t, miles	Service and the service of the servi						¥.2045. \$	· · · · · · · · · · · · · · · · · · ·	
upture, Fish Mouth, 4.5 in	•	•							(

Position (Top, Bottom, include position on pipe, 6 O'clock): (1)

Description of Failure (Corrosion Gouge, Seam Split):

² Initial volume lost or spilled

³ Including cleanup cost

Pipe Failure DescriptionNA						
3 O'clock Long seam						
Laboratory Analysis: X Yes No (not yet completed)						
Performed by: Det Norske Veritas (U.S.A.), Inc.						
Preservation of Failed Section or Component: XYesNo						
Wrapped in plastic and crated for If Yes - Method: shipment to Det Norske Veritas (U.S.A.), Inc., Dublin, Ohio						
In Custody of: Det Norske Veritas (U.S.A.), Inc.						
Develop a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, direction of flow, etc. Bar Hole Test Survey Plot, if included, should be outlined with concentrations at test points. N/A						
Component Failed: XN/A						
Component Failed; Manufacturer:		Model:		······································	\"\"\"\"\"\"\"\"\"\"\"\"\"\"\"\"\"\"\"	
Pressure Rating:		Size:	4.1.		<u> </u>	
Other (Breakout Tank, Underground Storage):		SIZE.				
Onto (Dicarout Frank, Onto Erotha Storage).		er Landen en en er frank en samme sande			25/40-44	
Pipe Data N/A						
Material: Carbon Steel	Wall Thickness/SDR: 0,260"					
Diameter (O.D.): 24"	Installation Date: 1989					
SMYS: <i>X60</i>	Manufacturer: Armco					
Longitudinal Seam: DSAW	Type of Coating: 3-layer Polyolefin					
Pipe Spécifications (API 5L, ASTM A53, etc.): API 5L						
Joining X N/A						
Type:	Procedure:					
NDT Method: Inspe			Inspected: Yes No			
Pressure @ Time of Failure @ Failure Site						
Pressure @ Failure Site: 694 psi Elevation @ Failure Site:						
Pressure Readings @ Va	· · · · · · · · · · · · · · · · · · ·			om Failure Site		
Location/M.P./Station #		re (psig)	Elevation (ft msl)	Upstream	Downstream	
Tracy Kick off discharge		1 psig	588 ft.	X		
Marsh Creek suction 36.		5 psig	422 ft.	in the second se	X	
Upstream Pump Station Data N/A						
Type of Product: Crude Oil	API Gravity: 15.2					
Specific Gravity: N/A	Flow Rate: 6,126 B.Ph.					
Pressure @ Time of Failure (4) 694 psi	Distance to Failure Site: 1 mile					
High Pressure Set Point: 957 psi	Low Pressure Set Point: 25 psi					

⁴ Obtain event logs and pressure recording charts

Upstream Compres	sor Station Data X: N/A						
Specific Gravity:	Flow Rate:						
Pressure @ Time of Failure (4)	Distance to Failure Site:						
High Pressure Set Point:	Low Pressure Set Point:						
	g Pressure N/A						
Max. Allowable Operating Pressure: 936 psi	Determination of MAOP: Pipe design pressure and 80% of hydrotest						
Actual Operating Pressure: 694 psi							
Method of Over Pressure Protection: relief valve							
Relief Valve Set Point: 645 psi	Capacity Adequate? X Yes No						
Integrity Test After Failure Pressure test conducted in place? (Conducted on Failed Components or Associated Piping): XYes No							
If No, tested after removal?	Yes No						
Method: 8 -hour Hydrotest and a 10 - minute Spike Hydrote							
Describe any failures during the test. None	31						
Soil/water Conditions (a) Failure Site Condition of and Type of Soil around Failure Site (Color, Wet, Dry, Frost Depth): Soil conditions – Dry, Pasture with Vegetation. Type of Backfill (Size and Description): local backfill from landowner property							
Type of Water (Salt, Brackish): No Water in area	Water Analysis (5) Yes XNo						
External Pipe or Comp							
External Corrosion? Yes No (1)	Coating Condition (Disbonded, Non-existent): (1)						
Description of Corrosion:							
Description of Failure Surface (Gouges, Arc Burns, Wrinkle Ber	nds, Cracks, Stress Cracks, Chevrons, Fracture Mode, Point of						
Origin): Above Ground: Yes No (1)	Buried: Yes No (i)						
Stress Inducing Factors: (1)	Depth of Cover: (i)						
Cathodi	Protection X N/A						
P/S (Surface):	P/S (Interface):						
Soil Resistivity: pH:	Date of Installation:						
Method of Protection:							
Did the Operator have knowledge of Corrosion before the Incident? YesNo							
How Discovered? (Close Interval Survey, Instrumented Pig, An	nual Survey, Rectifier Readings, ECDA, etc):						
	emponent Examination X N/A						
Internal Corrosion: Yes No (1)	Injected Inhibitors: Yes No						
Type of Inhibitors:	Testing: Yes No						

⁵ Attach copy of water analysis report

Internal Pipe or Co	omponent Examination XNA
Devilte (Course Test Course in Posistones Busha)	
Results (Coupon Test, Corrosion Resistance Probe):	The two Made Deigt of Origin).
Description of Failure Surface (MIC, Pitting, Wall Thinning, Che	evrons, Fracture Mode, Point of Origin):
	Construction 1 Action 187
Cleaning Pig Program: Yes No	Gas and/or Liquid Analysis: Yes No
Results of Gas and/or Liquid Analysis (6)	
Internal Inspection Survey: Yes No	Results ⁽⁷⁾
Did the Operator have knowledge of Corrosion before the Incide	nt?YesNo
How Discovered? (Instrumented Pig, Coupon Testing, ICDA, etc.	c.):

Responsible Party:	Force Damage XN/A Telephone No.:
Address:	relephone ivo
Work Being Performed:	(1)
Equipment Involved:	(1) Called One Call System? Yes No
One Call Name:	One Call Report # (8)
Notice Date:	Time:
Response Date:	Time:
Details of Response:	
Was Location Marked According to Procedures? Yes	No
Pipeline Marking Type:	(1) Location: (1)
State Law Damage Prevention Program Followed?Yes	NoNo State Law
Notice Required: Yes No	Response Required:YesNo
Was Operator Member of State One Call?YesNo	Was Operator on Site? Yes No
Did a deficiency in the Public Awareness Program contribute to	the accident?YesNo
Is OSHA Notification Required?YesNo	
Natu	ral Förces X. N/A
Description (Earthquake, Tornado, Flooding, Erosion):	
Failio	re Isolation <u>N</u> A
Squeeze Off/Stopple Location and Method: N/A	(1)
Valve Closed - Upstream	I.D.: Tracy Station

⁶ Attach copy of gas and/or liquid analysis report 7 Attach copy of internal inspection survey report 8 Attach copy of one-call report

Faily	re IsolationN/A
Time: 0038hrs. Pacific Time	M.P.: 136
Valve Closed - Downstream:	I.D.: Marsh Creek
Time: 0238hrs. Pacific Time	M.P.: 156
Pipeline Shutdown Method:ManualAutoma	tic SCADA X Controller ESD
Failed Section Bypassed or Isolated: Isolated	
Performed By: <i>Derek Ferraro</i>	Valve Spacing: 20 miles
Off	orization X N/A
Gas Odorized:YesNo	Concentration of Odorant (Post Incident at Failure Site):
Method of Determination: Yes No	% LEL:Yes No
	Time Taken: Yes No
Was Odorizer Working Prior to the Incident?	Type of Odorizer (Wick, By-Pass):
YesNo	
Odorant Manufacturer:	Type of Odorant:
Model:	
Amount Injected:	Monitoring Interval (Weekly):
Odorization History (Leaks Complaints, Low Odorant Levels, M	Monitoring Locations, Distances from Failure Site):
Weathe	-Conditions N/A
Temperature: 55 °F	Wind (Direction & Speed); 18 mph
Climate (Snow, Rain): Weather: Clear, Visibility: 10 Miles.	Humidity: 62% Barometer: 29.71"Hg,
Was Incident preceded by a rapid weather change? Yes	X No
	ights, Snow, Rain, Fog): Temp - 80 °F/57 °F, Weather - Clear,
Wind - 13 mph, Barometer 29.71"Hg, Visibility 10 Miles.	
Gas Mig	ration Survey X N/A
Bar Hole Test of Area: Yes No	Equipment Used:
Method of Survey (Foundations, Curbs, Manholes, Driveways,	Mains, Services) (9) (1)
Environment	Sensitivity Impact N/A
Location (Nearest Rivers, Body of Water, Marshlands, Wildlife	
by the medium loss): No impacted water or wildlife	
OPA Contingency Plan Available? XYes No	Followed? XYesNo
Class Location/H	igh Consequence Area X N/A
Class Location: 1 2 3 4 N/A	HCA Area? XYes No N/A
Determination: N/A	Determination: Drinking Water & Ecological

⁹ Plot on site description page

		Class	Location/	High Cons	equence Area	164 164 184 184 185	X.WA.
Odorization Required?	Yes	No	XN/A			 ,	

		(Expand List as I	recession y/			
	Req'd ⁽¹⁰⁾ Assessment Deadline Date	Test Date	Test Medium	Pressure (psig)	Duration (hrs)	% SMYS
Installation	N/A	11/20/1989	Water	1200	8	92.3%
Next						
Next				,		
Most Recent	,			· , ·		

	Intern	等。2000年中国的第三人称单数的企业的企业的企业。 第二人	ction/Other Asses List as Necessary)	ssment History	N/A
	Req'd (10) Assessment Deadline Date	Assessment Date	Type of ILI Tool (11)	Other Assessment Method (12)	Indicated Anomaly If yes, describe below
Initial		8/3/2005	MFL/GEOM	ILI	Yes X No
Next	8/3/2007	6/1/2007	MFL/GEOM	ILI	XYes No
Next	6/1/2009	5/7/2009	MFL	ILI	X Yes No
Next	5/7/2011	4/20/2011	MFL/GEOM	ILI	Yes XNo
Next	4/20/2013	6/27/2013	MFL	ILI	Yes XNo
Next	6/27/2015	8/6/2015	MFL/GEOM	ILI	Yes XNo
Next	a eskeras e mercena emercena con semenalmenta emendente emegran comunicata emercena escenção e esfe	12/3/2015	MFL-C	ILI	XYes No
Most Recent	amandalizmanın septemberide izte di Andre di işle, İşlediye İş lediye yelle ev yelle ev yelle kerili kerili bir d	12/4/2015	UT-C	ILI	XYes No
N/A	IV/A	N/A	N/A	N/A	N/A

Describe any previously indicated anomalies at the failed pipe, and any subsequent pipe inspections (anomaly digs) and remedial actions. 6/1/2007 – 3 preventative digs performed. 5/7/2009 – 2 preventive digs performed, 12/2015 – 2 digs performed.

Pre-Eailure Conditions and ActionsN/A
Was there a known pre-failure condition requiring (10) the operator to schedule evaluation and remediation? Yes (describe below or on attachment) X No
If there was such a known pre-failure condition, had the operator established and adhered to a required ⁽¹⁰⁾ evaluation and remediation schedule? Describe below or on attachmentYesNo _XN/A
Prior to the failure, had the operator performed the required (10) actions to address the threats that are now known to be related to the cause of this failure? X YesNoN/A List below or on an attachment such operator-identified threats, and operator actions taken prior to the accident.
Describe any previously indicated anomalies at the failed pipe, and any subsequent pipe inspections (anomaly digs) and remedial actions.

¹⁰ As required of Pipeline Integrity Management regulations in 49CFR Parts 192 and 195

¹¹ MFL, TFI, UT, Combination, Geometry, etc.

¹² ECDA, ICDA, SCCDA, "other technology," etc.

Are Maps and Records Current? (13) Comments:	X Yes	Maps & Record No	S			<i>N</i> _4	
Leak Survey History (Trend Analysis, Leak Plots):							
Pipeline Operation History N/A							
Description (Repair or Leak Reports, Ex	xposed Pipe Rep	oorts):		war seit and sections	An and a second of the second of the second		
Did a Safety Related Condition Exist Pa	rior to Failure?	X Yes	No Re	ported?	X Yes	No	
Unaccounted For Gas: N/A			ignormative in the first the second s	and the state of t	A Section of the sect		
Over & Short/Line Balance (24 hr., We	ekly, Monthly/T	rend): N/A					
	Opera	tor/Contractor	Error			X NA	
Name:			Job Function:				
Title: Years of Experience:							
Training (Type of Training, Background):							
Was the person "Operator Qualified" as applicable to a precursor abnormal operating condition? Yes No N/A							
Was qualified individual suspended from performing covered task Yes No N/A							
Type of Error (Inadvertent Operation of	a Valve):	squedi murta e e e e e e e e e e e e e e e e e e e				The second secon	
Procedures that are required:	. y · · · · · · · · · · · · · · · · · ·		nyya maka managa maga panga /del>	Weaver a vertex to a decide and a second to second and a	THE RESERVE OF THE PERSON NAMED IN COLUMN TWO IS NOT THE PERSON NAMED IN COLUMN TWO IS NOT THE PERSON NAMED IN	The state of the s	
Actions that were taken:		a postania de la companya de la companya de companya d					
Pre-Job Meeting (Construction, Mainter	nance, Blow Do	wn, Purging, Iso	lation);	·····	edicamor		
Prevention of Accidental Ignition (Tag	& Lock Out, Ho	t Weld Permit):	<u> </u>	 	madan, and a second		
Procedures conducted for Accidental Ig	nition:		radional de la primeira de la comp ensa de la comp ensa de la compensa del la compensa de la compensa de la compensa de la compensa de la compensa de la compensa de la compensa de la compensa de la compensa de la compensa de la compensa de la compensa de la compensa della compensa de la compensa del la compensa del la	and the state of t	Character and an overland with the special	***************************************	
Was a Company Inspector on the Job?	Yes	_No	one of the second second second second second second second second second second second second second second se	Code on y marries for North Congress on the debase year			
Was an Inspection conducted on this portion of the job?YesNo							
Additional Actions (Contributing factor conducted):	s may include n	umber of hours a	t work prior to fai	lure or time	of day work	t being	
Training Procedures:	CHICATA CONTROL CONTRO	are the same of th		· · · · · · · · · · · · · · · · · · ·	·		
Operation Procedures:		·			and the state of t		
Controller Activities:		- At-					
Name	I	Title	Years Experience	I	s on Duty to Failure	Shift	
	- Land April 1997	****					
	<u> </u>	,					

¹³ Obtain copies of maps and records

	Delice at Law Property Service Colors (Associated		ractor Error	化双连换机 商业 电路压力	X: N/A
		er a regional de la companya de la companya de la companya de la companya de la companya de la companya de la c			 TATO STATE OF THE PARTY OF
					and the second
Alarm Parameters:				97.00	
High/Low Pressure Shutdown:	,			**************************************	
low Rate:		,		- 	
Procedures for Clearing Alarms:			- 		
ype of Alarm:			per l'alling de commission de la language de la la la la la la la la la la la la la 	,	·
Company Response Procedures fo	r Abnormal O	perations:			
Over/Short Line Balance Procedur	es:	THE RESERVE THE PROPERTY OF TH	· · · · · · · · · · · · · · · · · · ·	nanakan pamanya pamanya manakan kaominina dia bananga akayankapan	Mitalania di madipatia del papare de la
requency of Over/Short Line Bal	ance:	and the second section of the section of t	· · · · · · · · · · · · · · · · · · ·		 **************************************
Additional Actions:		· · · · · · · · · · · · · · · · · · ·		the first the same of the same	

Additional Actions Taken by the Operator

 $N/_{\ell}$

Make notes regarding the emergency and Failure Investigation Procedures (Pressure reduction, Reinforced Squeeze Off, Clean Up, Use of Evacuators, Line Purging, closing Additional Valves, Double Block and Bleed, Continue Operating Downstream Pumps):

Line was shut down. Under reduced operating pressure the line was started up to push the heavy crude oil out of the line with a lighter crude oil to facilitate an extended shutdown. Crack tool logs were reevaluated by the vendor and additional repair and investigation digs were conducted on the three segments of the bigger pipeline system that contain the same type of pipe. Pressure tests with a spike test were conducted on all three segments of the line.

Photo Documentation (1)

Overall Area from best possible view. Pictures from the four points of the compass. Failed Component, Operator Action, Damages in Area,

Address Markings, etc.

Address Mark	ings, etc.		-
Photo No.	Description	Photo No.	Description
1		16	
2		17	
3		18	
4		19	
5		20	
6		21	
7		. 22	
8		23	
9		24	
10		2,5	
11		26	
12		27	
13		28	
14		29	
15		30	The second secon

Camera Type:			,		
		Additional	Information Sources		
Agency	Nai	rate and the contract and the contract and	Title	s dignison. Di	Diago Novele
Police:	Ivai	TIG.	1106		Phone Number
Fire Dept.:	-				,
State Fire Marshal:					****
State Agency:		· · · · · · · · · · · · · · · · · · ·			
NTSB:					
EPA;					
USCG:					
FBI:					
ATF:					
OSHA:] 				
Insurance Co.:					***
FRA:					, ут
MMS:					THE RESIDENCE OF THE PARTY OF T
Television:					
Newspaper:			*		, <u>a</u>
Other:					·······
		Perso	ns Interviewed		
Nar	ne		Title		Phone Number
Robert C. Marshall		Emergency Res Awareness			
Michael Bringham	W-0-49/4 - 1-	Facilities Mana	ger, SJV Crude		
Gary McNatt		SJV Operations	s Supervisor		
Dave Harder		SJV Maintenan	ce Supervisor		
Alan Elliott		Western Region	Asset Integrity		**************************************
Bryce Brown		Rosen - Global	Strategy Management		
	;				-WH.U
			- Mineral -		

	Event Log
partment and P	is prior, during, and after the incident by time. (Consider the events of all parties involved in the incident, Fir olice reports, Operator Logs and other government agencies.)
Time / Date	Event
H. 1818 1 TO WAY HE A TO THE TO THE TOTAL PROPERTY OF THE TOTAL PR	
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		Investigation	Contact Log
Time	Date	Name	Description
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	Failure Investigation Docume	ntation Log			
Operator:	Unit #:	CPF #:		Date	
Appendix	Dogwoodstin Dogwitter		Date	FC	ΣÍΑ
Number	Documentation Description		Received	Yes	No
		TO THE STATE OF TH			

12		1985-1-1-Polaria		****	,
		· · · · · · · · · · · · · · · · · · ·			

Site Description

Provide a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Photos should be taken from all angles with each photo documented. Additional areas may be needed in any area of this guideline.

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: 12/31/2016

U.S Department of Transportation
Pipeline and Hazardous Materials Safety Administration

 Original Report Date:
 06/15/2016

 No.
 20160184 - 21575

 (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. All responses to the collection of information are mandatory. Send comments regarding this burden or any other aspect of this collection of information, including suggestions for reducing the 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/piceline/library/forms.

PART A - KEY REPORT INFORMATION

Sound Town (colored all these amply)	Original:	Supplemental:	Final:
Report Type: (select all that apply)		Yes	Yes
Last Revision Date:	08/05/2016		
Operator's OPS-issued Operator Identification Number (OPID):	31174		
2. Name of Operator	SHELL PIPELINE CO., L.P.		
Address of Operator:			
3a. Street Address		STREET 42ND FLOOR	
3b. City	HOUSTON		
3c. State	Texas		
3d. Zip Code	77002		
4. Local time (24-hr clock) and date of the Accident:	05/20/2016 00:35		
5. Location of Accident:			
Latitude:			
Longitude:			
National Response Center Report Number (if applicable):	1148267		
7. Local time (24-hr clock) and date of initial telephonic report to the National Response Center (if applicable):	05/20/2016 02:44		15
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 	5	*	
9. Estimated volume of commodity released unintentionally (Barrels):	500.00		
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):			
11. Estimated volume of commodity recovered (Barrels):	400.00	MISTON 10 10 10 10 10 10 10 10 10 10 10 10 10	
12. Were there fatalities?	No		
- If Yes, specify the number in each category:			
12a. Operator employees			X
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		101	
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	T		. E
13d. Workers working on the right-of-way, but NOT associated with this Operator			
13e, General public			

LOT T. (I I I I I I I I I I I I I I I I I I	
13f. Total injuries (sum of above) 14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	103
- if Yes, complete Questions 14a and 14b: (use local time, 24-hr cloc	
14a. Local time and date of shutdown:	05/20/2016 00:37
14b, Local time pipeline/facility restarted:	05/23/2016 13:00
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No .
17. Number of general public evacuated:	. 0
18. Time sequence (use local time, 24-hour clock):	
18a. Local time Operator identified Accident - effective 7-2014 changed to "Local time Operator identified failure":	05/20/2016 00:35
18b. Local time Operator resources arrived on site:	05/20/2016 02:17
PART B - ADDITIONAL LOCATION INFORMATION	
Was the origin of the Accident onshore?	Yes
If Yes, Complete C	
If No, Complete Q	
- If Onshore:	
2. State;	California
3. Zip Code:	95304
4. City	Tracy
5. County or Parish	Alameda
6. Operator-designated location:	Milepost/Valve Station
Specify:	137.3
7. Pipeline/Facility name:	North 20
8. Segment name/ID:	Tracy to Windmill Farms 24"
Was Accident on Federal land, other than the Outer Continental S (OCS)?	IND .
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found);	Underground
Specify:	Under soil
- If Other, Descr	
Depth-of-Cover 12. Did Accident occur in a crossing?	No No
	I NO
- If Yes, specify type below:	
- If Bridge crossing	
- If Bridge crossing — Cased/ Uncased:	
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing —	
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled	
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing —	
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled Cased/ Uncased/ Bored/drilled	
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing —	
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing — Cased/ Uncased/	
- 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 kno	
- 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 kno	ent:
- 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 kno	ent:
- 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 knothing and the point of the Accidence — See — If Offshore:	ent:
- 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 kno - Approx. water depth (ft) at the point of the Accident: - See — If Offshore: 13. Approximate water depth (ft) at the point of the Accident:	ent:
- 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 kno - Approx. water depth (ft) at the point of the Accident: - If Offshore: 13. Approximate water depth (ft) at the point of the Accident: 14. Origin of Accident:	ent:
- 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 knothing and the Accidence — September 13, Approximate water depth (ft) at the point of the Accident: 14. Origin of Accident: - In State waters - Specify:	ent:
- 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 kno - Approx. water depth (ft) at the point of the Accident: - If Offshore: 13. Approximate water depth (ft) at the point of the Accident: 14. Origin of Accident:	ent:
- 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 kno - Approx. water depth (ft) at the point of the Accident: - Separation of Accident: 13. Approximate water depth (ft) at the point of the Accident: 14. Origin of Accident: - In State waters - Specify: - State:	ent:
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing — Cased/ Uncased - If Water crossing — Cased/ Uncased - Name of body of water, if commonly knothing and the point of the Accident — Approx. water depth (ft) at the point of the Accident: - Yell Offshore: 13. Approximate water depth (ft) at the point of the Accident: 14. Origin of Accident: - In State waters - Specify: - State: - Area:	ent:
- 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 kno - Approx. water depth (ft) at the point of the Accident: - Sq 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 #:	ent:
- 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 knoted — - Approx. water depth (ft) at the point of the Accident: - Separate 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:	ent:
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing — Cased/ Uncased - If Water crossing — Cased/ Uncased - Name of body of water, if commonly knd - Name of body of water, if commonly knd - Approx. water depth (ft) at the point of the Accident: - Self 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:	ent:
- 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 knoted — - Approx. water depth (ft) at the point of the Accident: - Separate water depth (ft) at the point of the Accident: - In State waters - Specify: - State; - Area: - Block/Tract #: - Nearest County/Parish: - On the Outer Continental Shelf (OCS) - Specify: - Area:	ent:
- 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 knoted — - Approx. water depth (ft) at the point of the Accident: - Selection - Selecti	ent:
- 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 knoted — - Name of body of water,	ent: got:
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing — Cased/ Uncased - If Water crossing — Cased/ Uncased - Name of body of water, if commonly knoted — - Approx. water depth (ft) at the point of the Accidented — - Separate - Approx. water depth (ft) at the point of the Accidented — - If Offshore: 13. Approximate water depth (ft) at the point of the Accidented — - In State waters - Specify: - 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:	intrastate
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing — Cased/ Uncased - If Water crossing — Cased/ Uncased - Name of body of water, if commonly knd - Approx. water depth (ft) at the point of the Accident: - Approximate water depth (ft) at the point of the 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: 2. Part of system involved in Accident:	Intrastate Onshore Pipeline, Including Valve Sites
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing — Cased/ Uncased - If Water crossing — Cased/ Uncased - Name of body of water, if commonly knd - Approx. water depth (ft) at the point of the Accident: - Approx. water depth (ft) at the point of the Accident: 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: 2. Part of system involved in Accident: - If Onshore Breakout Tank or Storage Vessel, including Attacher	Intrastate Onshore Pipeline, Including Valve Sites
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing — Cased/ Uncased - If Water crossing — Cased/ Uncased - Name of body of water, if commonly knoth and the point of the Accident point of the Accident point of the Accident point of Accident point	intrastate Onshore Pipeline, Including Valve Sites
- 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 knoth and the point of the Accident and the point of the	intrestate Onshore Pipeline, Including Valve Sites Pipe
- If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing — Cased/ Uncased - If Water crossing — Cased/ Uncased - Name of body of water, if commonly knoted — - Approx. water depth (ft) at the point of the Accident — - See - 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: 2. Part of system involved in Accident: - If Onshore Breakout Tank or Storage Vesset, Including Attache Appurtenances, specify:	intrastate Onshore Pipeline, Including Valve Sites

3b. Wall thickness (in):	.260
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	60,000
3d. Pipe specification:	5LX
3e. Pipe Seam , specify:	DSAW
- If Other, Describe:	DOAV
3f. Pipe manufacturer:	ARMCO
3g. Year of manufacture;	1982
3h. Pipeline coating type at point of Accident, specify:	Polyolefin
- If Other, Describe:	1 diyololiii
- If Weld, including heat-affected zone, specify. If Pipe Girth Weld,	
3a through 3h above are required;	
- If Other, Describe:	
- If Valve, specify:	<u> </u>
- If Mainline, specify:	
- If Other, Describe:	
3i, Manufactured by:	
3j. Year of manufacture:	. , , , , , , , , , , , , , , , , , , ,
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	<u> </u>
Year item involved in Accident was installed:	1989
Material involved in Accident:	Carbon Steel
- If Material other than Cerbon Steel, specify:	
6. Type of Accident Involved:	Rupture
- If Mechanical Puncture - Specify Approx. size:	1
- If we chanical Puncture — Specify Approx. size. in. (axial) by	
in. (circumferential)	<u></u>
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other, Describe:	Longituditai
Approx. size: in, (widest opening) by	4.5
in, (length circumferentially or axially)	45.2
in, (length circumierentially of axially)	45.2
- If Other – Describe:	
- If Other – Describe:	
- If Other - Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION	
PART D - ADDITIONAL CONSEQUENCE INFORMATION	
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic	
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds	
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial	
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify ell that apply:	
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify ell that apply:	No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	No Yes
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify ell that apply:	Yes No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	Yes No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	Yes No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impaci: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil	Yes No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impaci: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil	Yes No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impaci: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Surface - Groundwater - Surface - Groundwater - Private Well	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impaci: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Private Well - Private Well - Public Water Intake	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Private Well - Public Water Intake 5b. Estimated amount released in or reaching water (Barrels): 5c. Name of body of water, if commonly known: 6. At the location of this Accident, had the pipeline segment or facility	Yes No No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impaci: 1a. If Yes, specify all that apply:	Yes No No No
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impaci: 1a. If Yes, specify all that apply:	Yes No No No Yes Yes Yes
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Public Water Intake 5b. Estimated amount released in or reaching water (Barrels): 5c. Name of body of water, if commonly known: 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)? 7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)? 7a. If Yes, specify HCA type(s): (Select all that apply)	Yes No No No Yes Yes Yes
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	Yes No No No Yes Yes Yes
PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Public Water Intake 5b. Estimated amount released in or reaching water (Barrels): 5c. Name of body of water, if commonly known: 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)? 7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)? 7a. If Yes, specify HCA type(s): (Select all that apply)	Yes No No No Yes Yes Yes

1		
Integrity Management Program?		
- High Population Area:		
Was this HCA identified in the "could affect"	- 1	
determination for this Accident site in the Operator's		
Integrity Management Program?		· · · · · · · · · · · · · · · · · · ·
- Other Populated Area		
Was this HCA identified in the "could affect" determinati	ion	
for this Accident site in the Operator's Integrity	1	
Management Program?		
- Unusually Sensitive Area (USA) - Drinking Water		Yes
Was this HCA identified in the "could affect" determinati	ion	700
	1011	Voc
for this Accident site in the Operator's Integrity		Yes
Management Program?		
- Unusually Sensitive Area (USA) - Ecological		Yes
Was this HCA identified in the "could affect" determination	iori	
for this Accident site in the Operator's Integrity	- 1	Yes
Management Program?	1	
8. Estimated cost to Operator - effective 12-2012, changed to "Estimated"	nated	Property Damage":
8a. Estimated cost of public and non-Operator private property		
	i	\$ 25,000
damage paid/reimbursed by the Operator – effective 12-2012,	- 1	\$ 25,000
"paid/reimbursed by the Operator" removed		
8b. Estimated cost of commodity lost		\$ 0
8c. Estimated cost of Operator's property damage & repairs		\$ 1,330,000
8d. Estimated cost of Operator's emergency response	T	\$ 1,585,000
8e. Estimated cost of Operator's environmental remediation		\$ 1,600,000
8f. Estimated other costs		\$ 0
Descri	he.	
	- 1	\$ 4,540,000
changed to "Total estimated property damage (sum of above)"		<u> </u>
PART E - ADDITIONAL OPERATING INFORMATION		
Estimated pressure at the point and time of the Accident (psig):		694.00
2. Maximum Operating Pressure (MOP) at the point and time of the		000.00
Accident (psig):	- 1	936.00
Describe the pressure on the system or facility relating to the		
Accident (psig):	1	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		No
restriction with pressure limits below those normally allowed by the	- 1	110
	1	
MOP?		
- 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?	- 1	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore		
Pipeline, Including Riser and Riser Bend" selected in PART C, Questi	מס	Yes
27		
- If Yes - (Complete 5a 5f below) effective 12-2012, changed	to "//"	Complete F. e. F. e. halowill
- n 165 - (Complete on - of below) effective 12-2012, Changed	W 10	
ng Tuno of Ingreson years dead to inmelli resiste selecce !		omplete o.a - o.e belowy
5a. Type of upstream valve used to initially isolate release		
source:		Remotely Controlled
source: 5b. Type of downstream valve used to initially isolate releas		Remotely Controlled
source: 5b. Type of downstream valve used to initially isolate release source:		Remotely Controlled Remotely Controlled
source: 5b. Type of downstream valve used to initially isolate releas		Remotely Controlled
source: 5b. Type of downstream valve used to initially isolate release source:		Remotely Controlled Remotely Controlled 16,125
source: 5b. Type of downstream valve used to initially isolate release source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal		Remotely Controlled Remotely Controlled
source: 5b. Type of downstream valve used to initially isolate release source: 5c. Length of segment isolated between valves (ft): 5d. is the pipeline configured to accommodate internal inspection tools?	se	Remotely Controlled Remotely Controlled 16,125 Yes
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate.	se	Remotely Controlled Remotely Controlled 16,125
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodati - Changes in line pipe diameter	se	Remotely Controlled Remotely Controlled 16,125 Yes
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - Changes in line pipe diameter - Presence of unsuitable mainline yalves	se	Remotely Controlled Remotely Controlled 16,125 Yes
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - Changes in line pipe diameter - Presence of unsuitable mainline valves - Tight or mitered pipe bends	se	Remotely Controlled Remotely Controlled 16,125 Yes
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - Changes in line pipe diameter - Presence of unsuitable mainline valves - Tight or mitered pipe bends - Other passage restrictions (i.e. unbarred tee's,	se	Remotely Controlled Remotely Controlled 16,125 Yes
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - 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.)	ion? (Remotely Controlled Remotely Controlled 16,125 Yes
source: 55. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - 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 magne	ion? (Remotely Controlled Remotely Controlled 16,125 Yes
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - 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.)	ion? (Remotely Controlled Remotely Controlled 16,125 Yes
source: 55. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - 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 magneflux leakage internal inspection tools)	ion? (Remotely Controlled Remotely Controlled 16,125 Yes
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - 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 magne flux leakage internal inspection tools) - Other -	ion? (Remotely Controlled Remotely Controlled 16,125 Yes
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - 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 magnetize flux leakage internal inspection tools) - Other -	ion? (Remotely Controlled Remotely Controlled 16,125 Yes
source: 5b. Type of downstream valve used to initially isolate releas source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodate - 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 magnetize leakage internal inspection tools) - Other - - If Other, Descriptions of the pipeline, are there operational factors which	ion? (Remotely Controlled Remotely Controlled 16,125 Yes select all that apply)
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PART F - DRUG & ALCOHOL TESTING INFORMATI	ON	
 As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT Drug & Alcohol Testing regulations? 	r's	No
- If Yes:	· · · · ·	, , , , , , , , , , , , , , , , , , , ,
1a. Specify how many were tested:		
	<u></u>	
1b. Specify how many failed:		
As a result of this Accident, were any Operator contractor employe tested under the post-accident drug and alcohol testing requirements DOT's Drug & Alcohol Testing regulations?	es of	No
- If Yes:		
2a. Specify how many were tested:		
2b. Specify how many falled:		
PART G – APPARENT CAUSE		
Select only one box from PART G in shaded column on left repre the questions on the right. Describe secondary, contributing or I	sen oot	ting the APPARENT Cause of the Accident, and answer 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	shad	ded left-hand column
Corrosion Failure - Sub-Cause:		
- If External Corrosion:		
Results of visual examination:		
- If Other, Descri	be.	
2. Type of corrosion: (select all that apply)	1	
- Galvanić		
- Atmospheric	[
- Stray Current		
- Microbiological		
- Selective Seam	}	
- Other:		
- If Other, Descr 3. The type(s) of corrosion selected in Question 2 is based on the fol	be.	res (as lost all that analy)
	OWI	ig. (select all trial apply)
Field examination Determined by metallurgical analysis		r
- Other:	†—	, the same of the
- If Other, Descri	bė:	, , , , , , , , , , , , , , , , , , , ,
4. Was the failed item buried under the ground?		
- If Yes :		
134a, Was falled item considered to be under cathodic		
protection at the time of the Accident?	<u> </u>	
If Yes - Year protection started:	<u> </u>	
4b. Was shielding, tenting, or disbonding of coating eviden	at	
the point of the Accident?	<u> </u>	
4c. Has one or more Cathodic Protection Survey been	Ì	
conducted at the point of the Accident?	od:	
if "Yes, CP Annual Survey" - Most recent year conduct		
If "Yes, Close Interval Survey" - Most recent year conduct		
If "Yes, Other CP Survey" - Most recent year conduct	ed.	
- If No:	1	<u> </u>
4d. Was the failed Item externally coated or painted?		
5. Was there observable damage to the coating or paint in the vicinity	OI	
the corrosion? - If Internal Corrosion:	 	
6. Results of visual examination:	 	
- Other:		
7. Type of corrosion (select all that apply): -	İ	
- Corrosive Commodity		
- Water drop-out/Acid		
- Microbiological		
- Erosion		
- Other:		
- If Other, Descr	ibe:	
8. The cause(s) of corrosion selected in Question 7 is based on the	follov	ving (select all that apply): -
- Field examination	1	

- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
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?	
Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Fallure sub-cause is selected in	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 Fallure sub-cause is selected.	AND the "Stem burelyed in Angidant" (From DADT C
Complete the following if any Corrosion Failure sub-cause is selected a Question 3) is Pipe or Weld.	AND the item involved in Accident (non-FART C,
15. Has one or more internal inspection tool collected data at the point of	fhe
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 ye	ear:
- Ultrasonic	
Most recent y	ear:
- Geometry Most recent y	200
	3d1.
- Caliper Most recent yo	par:
- Crack	
Most recent ye	ear.
- Hard Spot	
Most recent y	ear:
- Combination Tool	
Most recent y	9ar.
- Transverse Field/Triaxial Most recent y	ear:
- Other	
Most recent y	ear:
Descr	
16. Has one or more hydrotest or other pressure test been conducted sin	ce .
original construction at the point of the Accident?	1
If Yes - Most recent year tes	tod 1
Test pressu	W. J W
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 Accider	nt:
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, selections of the Accident since	at two of non-destructive examination and indicate most
recent year the examination was conducted:	type of horroperdoline evaluations and indicate most
- 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 picke	d from shaded left-handed column
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	\$
1. Specify:	
- If Other, Desc	fibe:
- if Heavy Reins/Floods: 2. Specify:	
- If Other, Desc	ribe:
- if Lightning:	
3. Specify:	
- If Temperature: 4. Specify:	
- if Other, Desc	ribe:
- if Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is	selected.
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, Desc	l l
- if Other, Desc	Upe:
G3 - Excavation Damage - only one sub-cause can be picked for	om shaded left-hand column
Excavation Damage Sub-Cause:	
- If Previous Damage due to Excavation Activity: Complete Que C, Question 3) is Pipe or Weld.	stions 1-5 ONLY IF the "Item Involved in Accident" (from PART
Has one or more internal inspection tool collected data at the point of the collected data at the point of the collected data.	
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:	
Descri	ribe:
Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
 Has one or more hydrotest or other pressure test been conducted s original construction at the point of the Accident? 	ince
- If Yes: Most recent year tes	tied-
Test pressure (p:	
Has one or more Direct Assessment been conducted on the pipeling	
segment?	
- If Yes, and an investigative dig was conducted at the point of the	
Most recent year conducted	
- if Yes, but the point of the Accident was not identified as a dig Most recent year conducted	
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:	<u></u>
- Wet Magnetic Particle Test	<u> </u>
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	ed as the sub-cause.
1	A CO SITO OCH ANGION
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: (select all that apply) -	
- Оле-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:	
	Fig
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)	
	ningst first level CCA DIDT Boot Course and then when
17. Description of the CGA-DIRT Root Cause (select only the one predom	miant matievel OGA-DIK Roof Cause and then, where
available as a choice, the one predominant second level CGA-DIRT Root	oause 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 se	elected from the shaded left-hand column
Other Guteide Ferre Camera Sub Causes	
Other Outside Force Damage – Sub-Cause:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NO	T Engaged in Excavation:
Vehicle/Equipment operated by:	
	sent or Vessels Set Adriff or Which Have Otherwise Last
Their Mooring	nent 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	

- Tornado		
- Heavy Rains/Flood		
- Other		
- If Other, Descr	ibe:	
-if Previous Mechanical Damage NOT Related to Excavation: Co Accident" (from PART C, Question 3) is Pipe or Weld.	iqmo	ete Questions 3-7 ONLY IF the "Item Involved in
 Has one or more internal inspection tool collected data at the poin the Accident? 	t of	
3a. If Yes, for each tool used, select type of internal inspection tool a	nd in	dicate 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:	ļļ	
- Transverse Field/Triaxial	<u> </u>	
Most recent year conducted:		
- Other		
Most recent year conducted: Descr	hor	
Do you have reason to believe that the internal inspection was	ue.	
completed BEFORE the damage was sustained?		,
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 tes	ed:	,
Test pressure (ps		
Has one or more Direct Assessment been conducted on the pipeline segment?	9	
- if Yes, and an investigative dig was conducted at the point of the Acc	dent:	
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	e	
point of the Accident since January 1, 2002? 7a. If Yes, for each examination conducted since January 1, 20	02, se	elect 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		
- Handrieid Oltrasonic 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:		
Descr	be:	
- If Intentional Damage:	. , .	
8. Specify;	lla c -	
- If Other, Description Force Paragon	ibe:	1
- If Other Outside Force Damage: 9. Describe:		
a. Describe.		
G5 - Material Failure of Pipe or Weld - only one sub-cause o	an be	selected from the shaded left-hand column
Use this section to report material failures ONLY IF the "Item In-	olve	d in Accident" (from PART C, Question 3) is "Pipe" or
"Weld."	-	Original Manufacturing-related (NOT girth weld or other
Material Failure of Pipe or Weld Sub-Cause:		welds formed in the field)

1. The sub-cause shown above is based on the following: (select all that apply)		
- Field Examination		
- Determined by Metallurgical Analysis	Yes	
- Other Analysis		
- If "Other Analysis", Describe:		
- Sub-cause is Tentative or Suspected; Still Under Investigation		
(Supplemental Report required)		
- If Construction, Installation, or Fabrication-related:		
List contributing factors: (select all that apply)	V->	
- Fatigue or Vibration-related	Yes	
Specify:	Mechanically-induced Fatigue prior to Installation (such as during transport of pipe)	
- If Other, Describe:	during transport of pipe)	
- Mechanical Stress:		
- Other		
- If Other, Describe:		
- If Environmental Cracking-related:	A CONTRACTOR OF THE CONTRACTOR	
3. Specify:		
- If Other - Describe:		
Complete the following if any Material Failure of Pipe or Weld sub-cau	se is selected.	
4. Additional factors: (select all that apply):		
- Dent		
- Gouge		
- Pipe Bend		
- Arc Burn		
- Crack	Yes	
- Lack of Fusion	, , , , , , , , , , , , , , , , , , ,	
- Lantination		
- Buckle		
- Wrinkle	<u></u>	
- Misalignment		
- Burnt Steel		
- Other: - If Other, Describe:		
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 a	nd indicate most recent year run:	
- Magnetic Flux Leakage	Yes	
Most recent year run:	2015	
- Ultrasonic	Yes	
Most recent year run:	2015	
- Geometry	Yes	
Most recent year run:	2013	
- Caliper .		
Most recent year run:		
- Crack	Yes	
Most recent year run:	2015	
- Hard Spot		
Most recent year run:		
- Combination Tool		
Most recent year run;		
- Transverse Field/Triaxial	Yes	
Most recent year run:	2015	
- Other		
Most recent year run:		
Describe:		
6. Has one or more hydrotest or other pressure test been conducted since	Yes	
original construction at the point of the Accident?	res	
- If Yes:		
Most recent year tested:.	1989	
Test pressure (psig):	1,190.00	
7. Has one or more Direct Assessment been conducted on the pipeline	No .	
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?	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:
Specify: (select all that apply) -
- Control Valve
- Instrumentation
- SCADA
- Communications - Block Valve
- Check Vaive
- Relief Valve
- Power Failure
- Stopple/Control Fitting
- ESD System Failure
- Other
- If Other Describe:
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 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:		
- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill of	or Overflow	
. 1. Specify:		
- If Other, Describe:		
- If Other Incorrect Operation	<u></u>	
2. Describe:		
Complete the following if any incorrect Operation sub-cause is select	ed.	
3. Was this Accident related to (select ell that apply): -		
- Inadequate procedure	1	
- No procedure established		
- Failure to follow procedure		
- Other:		
- If Other, Describe:		
4. What category type was the activity that caused the Accident?		
What category type was the activity that caused the Accident? Was the task(s) that led to the Accident identified as a covered task	<u> </u>	
in your Operator Qualification Program?	·	
5a. If Yes, were the individuals performing the task(s) qualified for		
the task(s)?	, the state of the	
G8 - Other Accident Cause - only one sub-cause can be selected f	rom the shaded left-hand column	
Other Accident Cause - Sub-Cause:		
- If Miscellaneous:		
1. Describe:		
- If Unknown:		
2. Specify:		
PART H - NARRATIVE DESCRIPTION OF THE ACCIDE	T	
5/20/16 00:35hrs PT the 24" pipe segment from Tracy to Windmilf Farms ruptured. The pipeline Houston Control Center SCADA detected an increase In flow rate and drop in discharge pressure. The Pump Station immediately shufdown on low suction. The Controller took action to stutdown the entire pipeline system and isolate the pipeline. Notifications were made to the field supervisor, the Control Center Supervisor. Personnel were sent to the area of the pump station to locate the exact location of the release. Following the replacement of the failed pipe joint the CSFM gave permission to displace the heavy crude oil from the pipeline with light crude oil before an agreed plan of action on the vintage pipe which failed. Inspections and repairs were initiated, along with hydro-static pressure testing of affected segments. The pipeline was re-started with the approval of the CSFM on July 19, 2016. The failed pipe was examined at a metallurgical laboratory. SPLC's Subject Matter Expert (SME) reviewed the analysis.		
PART I - PREPARER AND AUTHORIZED SIGNATURE		
Preparer's Name	Richard Klasen	
Preparer's Title	Regulatory Specialist	
Preparer's Telephone Number		
Preparer's E-mail Address		
Preparer's Facsimile Number		
Authorized Signer Name	Deborah Price	
Authorized Signer Title	Pipeline Ops Regulatory Manager	
Authorized Signer Telephone Number	A was a second	
Authorized Signer Email		
Date	08/05/2016	

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.

Original Report Date:

U.S Department of Transportation

Pipeline and Hazardous Materials Safety Administration

OMB NO: 2137-0047
EXPIRATION DATE: 12/31/2016

Official Report Date:

No. 20160184 - 21442

(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 CMB Control Number. The OMB Control Number for this information collection is 2137-0047. All responses to the collection of information are mandatory. Send comments regarding this burden or any other aspect of this collection of information, including suggestions for reducing the 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/library/forms.

PART A - KEY REPORT INFORMATION

Report Type: (select all that apply)	Original:	Supplemental:	Final:
Last Revision Date:	res		
Operator's OPS-issued Operator Identification Number (OPID):	31174		
Name of Operator	SHELL PIPELINE	CO L D	
	SHELL PIPELINE	CO., L.P.	
3. Address of Operator: 3a. Street Address	L 040 L OLUCIANIA C	TREET AOND ELOOR	
3b. City	HOUSTON	TREET. 42ND FLOOR	
3c. State			
	Texas		
3d. Zip Code	77002		
4. Local time (24-hr clock) and date of the Accident:	05/20/2016 00:35		
5. Location of Accident:			
Latitude:			
Longitude:	1110000		
National Response Center Report Number (if applicable):	1148267		
 Local time (24-hr clock) and date of initial telephonic report to the National Response Center (if applicable): 	05/20/2016 02:44		
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 			
9. Estimated volume of commodity released unintentionally (Barrels):	500.00		
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):			
11. Estimated volume of commodity recovered (Barrels):	400.00		
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	9	W W W	
12d. Workers working on the right-of-way, but NOT associated with this Operator	- (A)		
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:	1. 1.1.1		
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	#11-1		

13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	103
- If Yes, complete Questions 14a and 14b: <i>(use local time, 24-hr clock)</i>	
14a. Local time and date of shutdown;	05/20/2016 00:37
14b, Local time pipeline/facility restarted:	05/23/2016 13:00
- Still shut down? (* Supplemental Report Required)	00/20/20 10 10 10 10 10 10 10 10 10 10 10 10 10
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	0
18. Time sequence (use local time, 24-hour clock):	,
18a. Local time Operator Identified Accident - effective 7- 2014	07/00/0040 00 07
changed to "Local time Operator identified failure":	05/20/2016 00:35
18b. Local time Operator resources arrived on site:	05/20/2016 02:17
PART B - ADDITIONAL LOCATION INFORMATION	
Was the origin of the Accident onshore?	Yes
If Yes, Complete Ques	Ji
If No, Complete Questi	
- If Onshore:	0.10 (10 70)
2. State:	California
3. Zip Code:	95304
4. City	Tracy
5. County or Parish	Alameda
6. Operator-designated location:	Milepost/Valve Station
Specify:	137.3
7. Pipeline/Facility name:	North 20
8. Segment name/ID:	Tracy to Windmill Farms 24"
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):	84
10 0111	NI-
12. Did Accident occur in a crossing?	No
Did Accident occur in a crossing? If Yes, specify type below:	NO .
	NO .
- If Yes, specify type below:	NO .
- If Yes, specify type below: - If Bridge crossing –	NO
- If Yes, specify type below: - If Bridge crossing — Cased/ Uncased: - If Railroad crossing —	NO .
- If Yes, specify type below: - If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled	NO
- If Yes, specify type below: - If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing —	NO .
- If Yes, specify type below: - If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled	NO .
- If Yes, specify type below: - If Bridge crossing — Cased/ Uncased: - If Railroad crossing — Cased/ Uncased/ Bored/drilled - If Road crossing — Cased/ Uncased/ Bored/drilled - If Water crossing —	NO
- If Yes, specify type 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/	NO
- If Yes, specify type 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/ Bored/drilled - If Water crossing — Cased/ Uncased - Name of body of water, if commonly known:	NO .
- If Yes, specify type 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/	NO .
- If Yes, specify type 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:	NO .
- If Yes, specify type 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 - 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:	NO CONTRACTOR OF THE PROPERTY
- If Yes, specify type 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 - 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:	NO CONTRACTOR OF THE PROPERTY
- If Yes, specify type 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: - If Offshore: 13. Approximate water depth (ft) at the point of the Accident: 14. Origin of Accident:	NO
- If Yes, specify type 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 - 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:	NO CONTRACTOR OF THE PROPERTY
- If Yes, specify type 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:	NO CONTRACTOR OF THE PROPERTY
- If Yes, specify type 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: - If Offshore: 13. Approximate water depth (ft) at the point of the Accident: 14. Origin of Accident: - In State waters - Specify: - State:	NO CONTRACTOR OF THE PROPERTY
- If Yes, specify type 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: - If Offshore: 13. Approximate water depth (ft) at the point of the Accident: 14. Origin of Accident: - In State waters - Specify: - State: - Area:	NO CONTRACTOR OF THE PROPERTY
- If Yes, specify type 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: - If Offshore: 13. Approximate water depth (ft) at the point of the Accident: 14. Origin of Accident: - In State waters - Specify: - State: - Area: - Alea: - Block/Tract #:	NO CONTRACTOR OF THE PROPERTY
- If Yes, specify type 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: - 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:	NO CONTRACTOR OF THE PROPERTY
- If Yes, specify type 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: - 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 #:	NO CONTRACTOR OF THE PROPERTY
- If Yes, specify type 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:	
- If Yes, specify type 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: - 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 #:	
- If Yes, specify type 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: - Name of body of water, if commonly known: - Approx. water depth (ft) at the point of the Accident: - 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	Intrastate
- If Yes, specify type 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: - Neprox. water depth (ft) at the point of the Accident: - 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:	Intrastate
- If Yes, specify type 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: 2. Part of system involved in Accident:	
- If Yes, specify type 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: - Neprox. water depth (ft) at the point of the Accident: - 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:	Intrastate
- If Yes, specify type 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: 2. Part of system involved in Accident: - If Onshore Breakout Tank or Storage Vessel, Including Attached	Intrastate
- If Yes, specify type 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: 2. Part of system involved in Accident: - If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	Intrastate Onshore Pipeline, Including Valve Sites
- If Pridge 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: - Name of body of water, if commonly known: - Approx. water depth (ft) at the point of the Accident: - 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: 2. Part of system involved in Accident: - If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify: 3. Item involved in Accident:	Intrastate Onshore Pipeline, Including Valve Sites Pipe

3b. Wall thickness (in):	.260
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	60,000
3d. Pipe specification:	5LX
3e. Pipe Seam , specify:	DSAW
- If Other, Describe:	
3f. Pipe manufacturer:	ARMCO
3g. Year of manufacture:	1982
3h. Pipeline coating type at point of Accident, specify:	Polyolefin
- If Other, Describe:	
 If Weld, including heat-affected zone, specify. If Pipe Girth Weld, 	
3a through 3h above are required:	
- 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:	1989
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:	1 1 " "
	1
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	4.5
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION	56.4
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	56.4
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply:	56.4
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic	56.4
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds	56.4
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic	56.4
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial	No No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination:	No Yes
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned:	No Yes No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticlpated remediation:	No Yes
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply:	No Yes No
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in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater	No Yes No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil	No Yes No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticlpated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation	No Yes No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife	Yes No No
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in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	Yes No No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticlpated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination:	Yes No No
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in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	Yes No No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Surface - Groundwater - Drinking water: (Select one or both)	Yes No No
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in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticlpated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Drinking water: (Select one or both) - Private Well - Public Water Intake	Yes No No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticlpated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Drinking water: (Select one or both) - Private Well	Yes No No
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in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	Yes No No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Private Well - Public Water Intake 5b. Estimated amount released in or reaching water (Barrels): 5c. Name of body of water, if commonly known: 6. At the location of this Accident, had the pipeline segment or facility	No Yes No No No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	Yes No No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact:	No Yes No No No Yes Yes Yes
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Private Well - Public Water Intake 5b. Estimated amount released in or reaching water (Barrels): 5c. Name of body of water, if commonly known: 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? 7. Did the released commodity reach or occur in one or more High	No Yes No No No
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Public Water Intake 5b. Estimated amount released in or reaching water (Barrels): 5c. Name of body of water, if commonly known: 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? 7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	No Yes No No No Yes Yes Yes
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Private Well - Public Water Intake 5b. Estimated amount released in or reaching water (Barrels): 5c. Name of body of water, if commonly known: 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? 7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)? 7a. If Yes, specify HCA type(s): (Select all that apply)	No Yes No No No Yes Yes Yes
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Drinking water: (Select one or both) - Private Well - Public Water Intake 5b. Estimated amount released in or reaching water (Barrels): 5c. Name of body of water, if commonly known: 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? 7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)? 7a. If Yes, specify HCA type(s): (Select all that apply) - Commercially Navigable Waterway:	No Yes No No No Yes Yes Yes
in. (length circumferentially or axially) - If Other – Describe: PART D - ADDITIONAL CONSEQUENCE INFORMATION 1. Wildlife impact: 1a. If Yes, specify all that apply: - Fish/aquatic - Birds - Terrestrial 2. Soil contamination: 3. Long term impact assessment performed or planned: 4. Anticipated remediation: 4a. If Yes, specify all that apply: - Surface water - Groundwater - Soil - Vegetation - Wildlife 5. Water contamination: 5a. If Yes, specify all that apply: - Ocean/Seawater - Surface - Groundwater - Surface - Groundwater - Private Well - Public Water Intake 5b. Estimated amount released in or reaching water (Barrels): 5c. Name of body of water, if commonly known: 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? 7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)? 7a. If Yes, specify HCA type(s): (Select all that apply)	No Yes No No No Yes Yes Yes

Integrity Mareagement Program? - High Population Area: Was this HCA identified in the "could affeed" determination for this Accident site in the Operator's Integrity Management Program? - Other Population Area: Was this ICA identified in the "could affeed" determination with the Population Area: Was this ICA identified in the "could affeed" determination Management Program? - Unusually Sensitive Area (USA) - Drinking Water Was this HCA identified in the "could affeed" determination for this Accident site in the Operator's Integrity Management Program? - Unusually Sensitive Area (USA) - Ecological Was this HCA identified in the "could affeed" determination for this Accident site in the Operator's Integrity Management Program? - Unusually Sensitive Area (USA) - Ecological Was this HCA identified in the "could affeed" determination for this Accident site in the Operator's Integrity Management Program? - Estimated cost to Operator - effective 12-2012, changed to "Esvimated Very Base Sensitive Cost of Operator and non-Operator private property damage politriembursed by the Operator Integrity Company of the Cost of Commodity loss: - Estimated cost of Operator's property changes & repain - St. Estimated cost of Operator's property changes & repain - St. Estimated cost of Operator's property changes & repain - St. Estimated cost of Operator's environmental remediation - St. Estimated observed of Operator's environmental remediation - St. Estimated total of Operator's environmental remediation - St. Operating Pressure (Operator) - St. Vers Total estimated property damage (sum of above) - St. Vers Total estimated property damage (sum of above) - St. Vers Total estimated property damage (sum of above) - West Total estimated property damage (sum of above) - West Total estimated property damage (sum of above) - St.		
Was this HCA identified in the "could affect" determination for this Accident size in the Operator's Integrity Management Program? Other Populated Area Was this ICA identified in the "could affect" determination for this Accident size in the Operator's integrity Alareagement Program? - Unusually Sensitive Area (USA) - Dinking Water Ves Ves Was this HCA identified in the "could affect" determination or this Accident size in the Operator's integrity Alareagement Program? - Unusually Sensitive Area (USA) - Dinking Water Ves Was this HCA identified in the "could affect" determination for this Accident size in the Operator's Integrity Was size the HCA identified in the "could affect" determination for this Accident size in the Operator's Integrity B. Estimated cost to Operator - effective 12-2012, changed to "Estimated Property Damages". 8. Estimated cost to Operator - effective 12-2012, changed to "Estimated Property Damages". 8. Estimated cost of Commonity fost So. Estimated cost of Commonity fost So. Estimated cost of Operator's property damage & repairs Si. 500,000 So. Estimated cost of Operator's property damage & repairs Si. 500,000 So. Estimated cost of Operator's property damage & repairs Si. 500,000 So. Estimated cost of Operator's property damage & repairs Si. 500,000 So. Estimated cost of Operator's environmental remodulation Si. 600,000 So. Estimated cost of Operator's environmental remodulation Si. 600,000 So. Estimated cost of Operator's environmental remodulation Si. 600,000 So. Estimated cost of Operator's environmental remodulation Si. 600,000 So. Estimated cost of Operator's environmental remodulation Si. 600,000 So. Estimated cost of Operator's environmental remodulation Si. 600,000 So. Estimated cost of Operator's environmental remodulation Si. 600,000 So. Estimated cost of Operator's environmental remodulation Si. 600,000 So. Estimated ost of Operator's environmental remodulation Si. 600,000 So. Estimated ost of Operator's environmental remodulation Si.		
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86. Estimated cost of Operator's emergency response 87. Estimated cost of Operator's environmental remediation 87. Estimated other costs 88. Estimated total costs (sum of above) — effective 12-2012, changed to "Total estimated property damage (sum of above)" **PART E - ADDITIONAL OPERATING INFORMATION** 1. Estimated pressure at the point and time of the Accident (psig): 2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig): 3. Describe the pressure on the system or facility relating to the Accident (psig): 4. Not including pressure in the system or facility relating to the Accident (psig): 4. Not including pressure in the system or facility relating to the Accident (psig): 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? - 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 Pipelline, Including Valve Sites" OR "Offshore Pipelline, Including Riser and Riser Bend" selected in PART C, Question 2? - If Yes - (Complete 5a. – 5f below) effective 12-2012, changed to "(Complete 5.a – 5.e below)" 5a. Type of ownstream valve used to initially isolate release source: 5b. Type of downstream valve used to initially isolate release source: 5c. Length of segment isolated between valves (ft): 6d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodation? - 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 teakage internal inspection tools)		· · · · · · · · · · · · · · · · · · ·
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Bg. Estimated total costs (sum of above) – effective 12-2012, changed to "Total estimated property damage (sum of above)" PART E - ADDITIONAL OPERATING INFORMATION 1. Estimated pressure at the point and time of the Accident (psig): 936.00 2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig): 936.00 3. Describe the pressure on the system or facility relating to the Accident (psig): 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? - 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 Pipelline, Including Valve Sites" OR "Offshore Pipelline, Including Riser and Riser Bend" selected in PART C, Question 2? - If Yes - (Complete 5a. – 5f below) effective 12-2012, changed to "(Complete 5.a – 5.e below)" 5a. Type of upstream valve used to initially isolate release source: 5b. Type of downstream valve used to initially isolate release source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodation? (select all that apply) - Changes in line pipe diameter - Presence of unsultable mainline valves - Tight or mitered pipe bends - Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.) - Extra thirko, pipe wall (applicable only for magnetic flux leakage internal inspection tools)		φ υ
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5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2? - If Yes - (Complete 5a 5f below) effective 12-2012, changed to "(Complete 5.a - 5.e below)" 5a. Type of upstream valve used to initially isolate release source: 5b. Type of downstream valve used to initially isolate release source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - If No, Which physical features limit tool accommodation? (select all that apply) - Changes in line pipe dlameter - 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)	4b. Was this pressure restriction mandated by PHMSA or the	
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- If Yes - (Complete 5a 5f below) effective 12-2012, changed to "(Complete 5.a - 5.e below)" 5a. Type of upstream valve used to initially isolate release source: 5b. Type of downstream valve used to initially isolate release source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - 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)		Yes
- If Yes - (Complete 5a. – 5f below) effective 12-2012, changed to "(Complete 5a. – 5.e below)" 5a. Type of upstream valve used to initially isolate release source: 5b. Type of downstream valve used to initially isolate release source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - 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)		
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source: 5b. Type of downstream valve used to initially isolate release source: 5c. Length of segment isolated between valves (ft): 5d. Is the pipeline configured to accommodate internal inspection tools? - 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)		
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5d. Is the pipeline configured to accommodate internal inspection tools? - 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)		16 125
inspection tools? - 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)		10,140
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- 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)		(soloot all that apply)
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)		(ocieul all that apply)
- 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)		
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projecting instrumentation, etc.) - Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)		
Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)		
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 No		No No
run?	run?	
- If Yes, Which operational factors complicate execution? (select all that apply)	- If Yes, Which operational factors complicate execution? (select all that a)	oply)

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
Was a Supervisory Control and Data Acquisition (SCADA)-based	Yes
system in place on the pipeline or facility involved in the Accident?	163
If Yes -	1
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
	163
6c. Did SCADA-based information (such as alarm(s),	.,
alert(s), event(s), and/or volume calculations) assist with	Yes
the detection of the Accident?	
6d. Did SCADA-based information (such as alarm(s),	•
alert(s), event(s), and/or volume calculations) assist with	No
the confirmation of the Accident?	
7. Was a CPM leak detection system in place on the pipeline or facility	
involved in the Accident?	Yes
- If Yes:	
7a. Was it operating at the time of the Accident?	Yes
7b. Was it fully functional at the time of the Accident?	Yes
7c. Did CPM leak detection system information (such as	
alarm(s), alert(s), event(s), and/or volume calculations) assist	Yes
with the detection of the Accident?	
7d. Did CPM leak detection system information (such as	Nie
alarm(s), alert(s), event(s), and/or volume calculations) assist	No
with the confirmation of the Accident?	
	CPM leak detection system or SCADA-based information
How was the Accident initially identified for the Operator?	(such as alarm(s), alert(s), event(s), and/or volume
•	calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including	
oa. If Controller, Eodal Operating Fersoniter, including	·
contractors", "Air Patrol", or "Ground Patrol by Operator or its	
contractor" is selected in Question 8, specify:	
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	Yes, specify investigation result(s): (select all that apply)
Accident?	
- 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)	T.
- 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	Yes
Operator), and other factors associated with fatigue	
- 1 1	The Controllers response was compliant and effective. The
	size and consequence of the release was minimized as
Mandal an amazana for the co	required by procedure. Notification to field personnel was
Provide an explanation for why not:	compliant to notification to the Console Supervisor. There
	were no issues to note in regards to Control Center
	response. There were no fatigue related issues. No drug
<u> </u>	testing was required.
Investigation identified no control room issues	Yes
- Investigation identified no controller issues	Yes
- Investigation identified incorrect controller action or	100
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	
	·
response	

PART F - DRUG & ALCOHOL TESTING INFORMATION	
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?	No
- If Yes:	
1a. Specify how many were tested:	
1b. Specify how many failed:	· · · · · · · · · · · · · · · · · · ·
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? - If Yes:	No
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 represent the questions on the right. Describe secondary, contributing or root	
Apparent Cause:	G5 - Material Failure of Pipe or Weld
G1 - Corrosion Failure - only one sub-cause can be picked from shad	ded left-hand column
Corrosion Failure – Sub-Cause:	
- If External Corrosion:	
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	ar (extent all that apply)
- Field examination	g. (select all that apply)
- 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:	And the second s
- If No:	
4d. Was the falled item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
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 follow	ing (select all that apply): ~

- 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?	
Was the interior coated or lined with protective coating? 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 A	MD the "Item involved in Accident" (from PART C
Question 3) is Tank/Vessel.	THE REIL INVOIVED IN ACCIDENT (NOINT AIXT O,
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 A	AND the "Item Involved in Accident" (from PART C.
Question 3) is Pipe or Weld.	and the least inversed in vice of
15. Has one or more internal inspection tool collected data at the point of t	he l
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 ye	ear:
- Ultrasonic	
Most recent ye	ear:
- Geometry	
Most recent ye	ear;
- Caliper	
Most recent ye	ear:
- Crack	
Most recent ye	1
	er:
- Hard Spot	
- Hard Spot Most recent ye	
- Hard Spot Most recent ye - Combination Tool	ear:
- Hard Spot Most recent ye - Combination Tool Most recent ye	ear:
- Hard Spot Most recent ye - Combination Tool Most recent ye - Transverse Field/Triaxial	ear:
- Hard Spot Most recent ye - Combination Tool Most recent ye - Transverse Field/Triaxial Most recent ye	ear:
- Hard Spot Most recent ye - Combination Tool Most recent ye - Transverse Field/Triaxial Most recent ye - Other	ear: ear:
- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet	ear: ear: ear:
- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet Descri	ear: ear: ear: bear: bear:
- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet Description Most recent yet Mos	ear: ear: ear: bear: bear:
- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet Description 16. Has one or more hydrotest or other pressure test been conducted sincoriginal construction at the point of the Accident?	ear: ear: ear: bear: bear:
- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet - Other Most recent yet Description 16. Has one or more hydrotest or other pressure test been conducted sincoriginal construction at the point of the Accident? If Yes -	ear: ear: ear: ear: ear: ear: ear: ear:
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- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet Descrit 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 test Test pressur 17. Has one or more Direct Assessment been conducted on this segment	ear: ear: ear: ear: ear: ear: ear: ear:
- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet Descrit 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 test Test pressur 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.	ear: ear: ear: ear: ear: ear: ear: ear:
- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet - Other Most recent yet Descrit 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 test 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:	ear: ear: ear: ear: ear: ear: ear: ear:
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- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet - Other Most recent yet Descri 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 test 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?	ear: ear: ear: ear: ear: ear: ear: ear:
- Hard Spot Most recent yet - Combination Tool Most recent yet - Transverse Field/Triaxial Most recent yet - Other Most recent yet - Other Most recent yet Descrit 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 test Test pressure 17. Has one or more Direct Assessment been conducted on this segment at the point of the Accident Most recent year conducted: - 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	ear: ear: ear: ear: ear: ear: ear: ear:
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- Hard Spot - Combination Tool - Combination Tool - Most recent yether and the point of the Accident Most recent year test per conducted on this segment of Yes, and an investigative dig was conducted at the point of the Accident was not identified as a dig site: - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - Most recent year conducted: - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - Most recent year conducted: - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - Radiography	ear: ear: ear: ear: ear: ear: ear: ear:
- Hard Spot - Combination Tool Most recent yether and the point of the Accident Ac	ear: ear: ear: ear: ear: ear: ear: ear:
- Hard Spot - Combination Tool Most recent yether and the point of the Accident Ac	ear: ear: ear: ear: ear: ear: ear: ear:
- Hard Spot - Combination Tool - Most recent yether and the point of the Accident year conducted: - If Yes, but the point of the Accident was not identified as a dig site: - If Yes, but the point of the Accident was not identified as a dig site: - If Yes, for each examination conducted since of the Accident was not identified as a dig site: - Radiography - Radiography - Guided Wave Ultrasonic - Guided Wave Ultrasonic - Most recent year conducted: - Most recent year conducted: - Most recent year conducted: - Radiography - Guided Wave Ultrasonic - Most recent year conducted: - Most recent year conducted: - Guided Wave Ultrasonic - Most recent year conducted: - Most recent year conducted: - Guided Wave Ultrasonic	ear: ear: ear: ear: ear: ear: ear: ear:
- Hard Spot - Combination Tool - Most recent yether and the property of the Accident of the Accident year conducted: - If Yes, but the point of the Accident was not identified as a dig site: - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - Radiography - Radiography - Guided Wave Ultrasonic - Guided Wave Ultrasonic - Most recent year conducted: - Most recent year conducted: - Most recent year conducted: - Radiography - Guided Wave Ultrasonic - Most recent year conducted: - Most recent year conducted: - Most recent year conducted: - Radiography - Most recent year conducted: - Most recent year conducted: - Radiography - Most recent year conducted: - Most recent year conducted: - Radiography - Most recent year conducted: - Handheld Ultrasonic Tool	ear: ear: ear: ear: ear: ear: ear: ear:
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- Hard Spot - Combination Tool - Most recent yether - Transverse Field/Triaxial - Other - Other - Most recent yether - Other - Most recent yether - Most recent yether - Other - Most recent yether - Most recent yether - Most recent yether - Most recent yether - Most recent yether - Most recent yether - Most recent yether - Most recent yether - If Yes, and an investigative dig was conducted at the point of the Accident - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - Most recent year conducted: - Radiography - Guided Wave Ultrasonic - Most recent year conducted: - Handheld Ultrasonic Tool - Most recent year conducted: - Wet Magnetic Particle Test - Most recent year conducted: - Most recent year conducted: - Wet Magnetic Particle Test - Most recent year conducted: - Most recent year conducted: - Wet Magnetic Particle Test	ear: ear: ear: ear: ear: ear: ear: ear:
- Hard Spot - Combination Tool - Most recent yether and the point of the Accident yether and an investigative dig was conducted at the point of the Accident yether and an investigative dig was conducted since of the Accident yether and an investigative dig was conducted since of the Accident year tester and an investigative dig was conducted at the point of the Accident was not identified as a dig site: - Most recent year conducted: - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - If Yes, for each examination conducted since January 1, 2002, selective ent year the examination was conducted: - Radiography - Guided Wave Ultrasonic - Most recent year conducted: - Handheld Ultrasonic Tool - Most recent year conducted: - Wet Magnetic Particle Test - Dry Magnetic Particle Test - Most recent year conducted: - Dry Magnetic Particle Test	ear: ear: ear: ear: ear: ear: ear: ear:
- Hard Spot - Combination Tool - Most recent yether - Transverse Field/Triaxial - Other - Other - Most recent yether - Other - Most recent yether - Most recent yether - Other - Most recent yether - Most recent yether - Most recent yether - Most recent yether - Most recent yether - Most recent yether - Most recent yether - Most recent yether - If Yes, and an investigative dig was conducted at the point of the Accident - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - If Yes, but the point of the Accident was not identified as a dig site: - Most recent year conducted: - Most recent year conducted: - Radiography - Guided Wave Ultrasonic - Most recent year conducted: - Handheld Ultrasonic Tool - Most recent year conducted: - Wet Magnetic Particle Test - Most recent year conducted: - Most recent year conducted: - Wet Magnetic Particle Test - Most recent year conducted: - Most recent year conducted: - Wet Magnetic Particle Test	ear: ear: ear: ear: ear: ear: ear: ear:

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 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 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.		
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:		
Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?		
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 (pslg):		
4. Has one or more Direct Assessment been conducted on the pipeline seament?		
- 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		
OF FIRE OFFICE THAT GOOD GOVERNMENT DOOR CONTINUED BY		

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:	<u> </u>
Complete the following if Excavation Damage by Third Party is select	ed as the sub-cause.
	1
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	<u> </u>
Complete the following mandatory CGA-DIRT Program questions if an	v Evaquation Damaga aub payan is polarited
Complete the following manuatory COA-DIKT Flogram questions if an	/ 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	T
- If "Public", Specify:	
- Private	
- If "Private", Specify:	· · · · · · · · · · · · · · · · · · ·
	<u> </u>
- 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 predor	
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 s	elected from the shaded left-hand column
Other Outside Force Damage – Sub-Cause:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NO	T Engaged in Excavation:
Vehicle/Equipment operated by:	- migages in accuration
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equip	ment or Vessels Set Adrift or Which Have Otherwise Leet
Their Mooring:	ment of vessels set Admit of Whiteh Have Otherwise Lost
Select one or more of the following IF an extreme weather event was a	a factor:
	. Taylur.
- Hurricane	
- Tropical Storm	

- Tornado		
- Heavy Rains/Flood		
- Other		
- If Other, Describe:		
- If Previous Mechanical Damage NOT Related to Excavation: Compl Accident" (from PART C, Question 3) is Pipe or Weld.	ete Questions 3-7 ONLY iF the "Item Involved in	
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 in	dicate most recent vear run:	
- Magnetic Flux Leakage	STOCKED THOOK FOOT FOR FOR	
Most recent year conducted:		
- Ultrasonic	10724-800	
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):		
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, s	elect 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 Involve "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 shown above is based on the following: (select all that	арріу)				
- Field Examination					
- Determined by Metallurgical Analysis	Yes				
- Other Analysis					
- If "Other Analysis", Describe:					
- Sub-cause is Tentative or Suspected; Still Under Investigation					
(Supplemental Report required)					
- If Construction, Installation, or Fabrication-related Or If Original Man	nufacturing-related:				
2. List contributing factors: (select all that apply)					
- Fatigue or Vibration-related	Yes				
Specify:	Mechanically-induced Fatigue prior to installation (such as				
	during transport of pipe)				
- If Other, Describe:					
- Mechanical Stress:					
- Other					
- If Other, Describe:					
- If Environmental Cracking-related:					
3. Specify:					
- If Other - Describe:					
Complete the following if any Material Fallure of Pipe or Weld sub-cau	se 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:					
- If Other, Describe:					
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 a					
- Magnetic Flux Leakage	Yes				
- Magnetic Flux Leakage Most recent year run:	Yes 2015				
- Magnetic Flux Leakage Most recent year run: - Ultrasonic	Yes 2015 Yes				
- Magnetic Flux Leakage Most recent year run: - Ultrasonic Most recent year run:	Yes 2015 Yes 2015				
- Magnetic Flux Leakage Most recent year run: - Ultrasonic Most recent year run: - Geometry	Yes 2015 Yes				
- Magnetic Flux Leakage Most recent year run: - Ultrasonic Most recent year run: - Geometry Most recent year run:	Yes 2015 Yes 2015 Yes 2015				
- Magnetic Flux Leakage Most recent year run: - Ultrasonic Most recent year run: - Geometry Most recent year run: - Caliper	Yes 2015 Yes 2015 Yes 2015				
- Magnetic Flux Leakage Most recent year run: - Ultrasonic Most recent year run: - Geometry Most recent year run:	Yes 2015 Yes 2015 Yes 2015				
- Magnetic Flux Leakage Most recent year run: - Ultrasonic Most recent year run: - Geometry Most recent year run: - Caliper Most recent year run:	Yes 2015 Yes 2015 Yes 2015 Yes 2013 Yes				
- 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:	Yes 2015 Yes 2015 Yes 2015 Yes 2013				
- 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	Yes 2015 Yes 2015 Yes 2015 Yes 2013				
- 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:	Yes 2015 Yes 2015 Yes 2015 Yes 2013				
- 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	Yes 2015 Yes 2015 Yes 2015 Yes 2013				
- 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:	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2013 Yes 2015 Yes				
- 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	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes	- 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:	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2013 Yes 2015 Yes		
- 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	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes	- 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:	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes	- 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:	Yes 2015 Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015
- 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: - Other Most recent year run: - Other Most recent year run: - Other	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes	- 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: - Hard Spot Most recent year run: - Combination Tool Most recent year run: - Transverse Field/Triaxial Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other	Yes 2015 Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015		
- 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: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other	Yes 2015 Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015				
- 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: - Hard Spot Most recent year run: - Combination Tool Most recent year run: - Transverse Field/Triaxial Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other	Yes				
- 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: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - Other 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	Yes 2015 Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015 Yes 2015 Yes 2015				
- 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: - Other Most recent year run: - Other 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?	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes 2015 No				
- 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: - Other Most recent year run: - Other Most recent year run: - Other Most recent year run: - If Yes: Most recent year run: - 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?	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes 2015 No				
- 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: - Other Most recent year run: - Other 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 year conducted: - If Yes, but the point of the Accident was not identified as a dig site-	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes 2015 No				
- 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: - Other Most recent year run: - Other 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 year conducted:	Yes 2015 Yes 2015 Yes 2013 Yes 2015 Yes 2015 Yes 2015 Yes 2015 Yes 2015 No				

- Fadlography Most recent year conducted: - Guided Wave Ultrasonic Not recent year conducted: - Handhold Ultrasonic Tool Most recent year conducted: - Wet Magnetic Particle Test Most recent year conducted: - Other - Other - Other - Most recent year conducted: - Other Most recent year conducted: - Other Most recent year conducted: - Other - Ge- Equipment Failure - only one sub-cause can be selected from the shaded left-hand column Equipment Failure - Sub-Cause: - If Mathunction of Control/Relief Equipment: - Specify: Gete all this agoly Control Valve - Instrumentation - SCADA - Committed one - Block Valve - Instrumentation - SCADA - Committed one - Block Valve - Power Failure - Flore Tellure - Stopple Control Fitting - Stopple Control Fitting - Stopple Control Fitting - Stopple Control Fitting - Stopple Control Fitting - Stopple Control Fitting - Other - Other - If Cther - Describe: - If Threaded Connection/Coupling Failure: - Specify: - If Other - Describe: - If Other	recent year the examination was conducted: -	elect type of horr-destractive examination and indicate most
Accorded Wave Ultrasoric Most recent year conducted:		
- Guided Weve Ultrasonio Nost recent year conducted: - Handhald Ultrasonio Tool - Most recent year conducted: - Wet Megnetic Particle Test - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Sub-Cause: - If Mathurction of Control/Relief Equipment: - Is peeting relief at the apply: - Control Valve - Instrumentation - ScADA - Communications - Block Valve - Chock Valve - Power Failure - Stoppie Cortor Priting - Stoppie Cortor Priting - Stoppie Cortor Priting - Stoppie Cortor Priting - Stoppie Cortor Priting - Stoppie Cortor Priting - Specify: - If Other - Describe: - If Pump or Pump-related Equipment: - Specify: - If Other - Describe: - If Non-threaded Connection Failure: - Specify: - If Other - Describe: - If Non-threaded Connection Failure: - Specify: - If Other - Describe: - If Most Guidpmant Failures - Overpressurfication - Overpressurfication - No support or loss of support - No support or loss of support - Na support or loss of support - Mannatox Ving defaut - Describes - Worthing and tubing fittings - Describes - Worthing - Mannatox Ing defaut - Na support or loss of support - Mannatox Ving defaut - Na support or loss of support - Mannatox Ving defaut - Loss of oloctricity - Improper installation - Mannatox Ving defaut - Valve audit or valve can contributed to the release - Alamystatus Gallure - Hother - Hother, Describes - Hother - Hother, Describes - Hother - Hother - Hother, Describes - Hother - Hother - Hother, Describes - Hother - Hother - Hother, Describes - Hother - Hother - Hother, Describes - Hother - Hother - Hother, Describes - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hother - Hothe		
- Handhold Ultrasonic Tool - Handhold Ultrasonic Tool - Wet Magnetic Particle Test - Wet Magnetic Particle Test - Dry Magnetic Particle Test - Other - Most recent year conducted: - Other - Most recent year conducted: - Describe: - Other - Most recent year conducted: - Describe: - G6 - Equipment Failure - only one sub-cause can be selected from the shaded left-hand coturn - Equipment Failure - Sub-Cause: - If Maffunction of Control/Relief Equipment: - Specify: - Goder of their apply: - Specify: - ScADA - SCADA - SCADA - SCADA - SCADA - Check Valve - Check Valve - Rolld Valve - Rolld Valve - Power Failure - Stopple Control Fitting - SS System Failure - Other - If Other - Describe: - If Pump or Pump-related Equipment: - If Threaded Connection/Coupling Failure: - If Other - Describe: - If Threaded Connection/Coupling Failure: - If Other - Describe: - If Other - Describe: - If Other Failure: - Specify: - If Other - Describe:		
- Handhold Ultrasonic Tool - Wet Magnetic Particle Test - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Sub-Cause: - Equipment Failure - only one sub-cause can be selected from the shaded left-hand column Equipment Failure - Sub-Cause: - If Marthunction of Control/Relief Equipment: - Specify (selected at that apply) - Control Valve - Instrumentation - SCADA - Communications - Block Valve - Check Valve - Check Valve - Check Valve - Relief Valve - Relief Valve - Power Faiture - Sub-piel Control Faiture - Sub-piel Control Faiture - Other - If Other - Describe: - If Pump or Pump-related Egulpment: - Specify: - If Other - Describe: - If Pump or Pump-related Egulpment: - Specify: - If Other - Describe: - If Threaded Connection Faiture: - Specify: - If Other - Describe: - If Non-threaded Connection Faiture: - Specify: - If Other - Describe: - If Other Egulpment Faiture - If Other - Describe: - If Other Egulpment Faiture - If Other - Describe: - If Other Egulpment Faiture - If Other - Describe: - If Other Egulpment Faiture - If Other - Describe: - If Other Egulpment Faiture - If Other - Describe: - If Other Egulpment Faiture - If Other - Describe: - If Other Egulpment Faiture - If Other - Describe: - If Other Egulpment Faiture - If Other - Describe: - Other - Describe: - Complete the following if any Equipment Faiture sub-cause is selected Administration of support - Non-threaded Connection Faiture: - Describe: Varieties of support - Manufacturing defeat - Loss of obscribe vibration - No support or loss of support - Manufacturing defeat - Amendacturing defeat - Handingment - Thermal stress - Other - Hi Other - Describe:		
- Wet Magnetic Particle Test - Wast recent year conducted: - Other - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - Most recent year conducted: - Other - 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: - Specify, celebrated if that apply: Instrumention - Instrumention - Instrumention - SCADA - Communications - Block Valve - Check Valve - Check Valve - Relief Valve - Power Failure - Stoppic Cortiol Fitting - Stoppic Cortiol Fitting - Stoppic Cortiol Fitting - Stoppic Cortiol Fitting - Stoppic Cortiol Fitting - Stoppic Cortiol Fitting - Stoppic Cortiol Fitting - If Other - Describe: - If Threaded Connection/Coupling Failure: - If Other - Describe: - If Threaded Connection Failure: - If Other - Describe: - If Other - Describe: - If Other Equipment Failure: - Specify: - If Other - Describe: - If Other Equipment Failure: - Specify: - If Other - Describe: - If Other Equipment Failure: - Specify: - If Other - Describe: - If Other Equipment Failure: - Specify: - If Other - Describe: - If Other Equipment Failure: - No support or loss of support - Manufacturing defect - Loss of electrality - Improper installation - Mismatched items (different manufacturer for tubing and tubing fittings) - Describe: - Breakdown of soft goods due to competibility issues with transported commodity - Valve valt or valve can contributed to the release - Alarm/status failure - Missingment - Internel stress - Other - If Other, Describe:		
- Wet Magnetic Particle Tost - Dry Magnetic Particle Tost - Other - Other - Most recent year conducted: - Describe: - Describe: - Describe: - Ge - Equipment Failure - only one sub-cause can be selected from the shaded left-hand column - Equipment Failure - Sub-Cause: - If Malfunction of Control/Railer Equipment: - Specify: Select all that apply) - Control Valve - Instrumentation - SCADA - Communications - SCADA - Communications - Block Valve - Check Valve - Power Failure - Sub-System Failure - Supplication Failure - Supplication Failure - Other - Other - If Other - Describe: - If Pump or Pump-related Equipment: - Specify: - If Other - Describe: - If Non-threaded Connection/Coupling Failure: - Specify: - If Other - Describe: - If Other Equipment Failure: - Specify: - If Other - Describe: - If Other - Describe: - If Other Equipment Failure: - Specify: - If Other - Describe: - If Other - Describe: - If Other - Describe: - If Other Equipment Failure: - Specify: - If Other - Describe: - If Other Equipment Failure: - Specify: - If Other - Describe:		
Most recent year conducted: - Other 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 Mathunction of Control/Relief Equipment: - Specify: Genetic all that apply Control Valve - Instrumentation - SCADA - Communications - Block Valve - Check Valve - Check Valve - Check Valve - Power Failure - Stopple/Control Pitting - ESD System Failure - Other - Other - Other - If Other - Describe: - If Pump or Pump-related Equipment: - Specify: - If Other - Describe: - If Threaded Connection/Coupling Failure: - Specify: - If Other - Describe: - If Mont-threaded Connection Failure: - Specify: - If Other - Describe: - If Other - Describe: - If Other Equipment Failure: - Other - Owenther Failure: - Owenther Failure: - Describe: - If Other - Describe: - If Other - Describe: - If Other Equipment Failure: - Describe: - If Other Equipment Failure: - Describe: - If Other Equipment Failure: - Describe: - If Other Equipment Failure: - Describe: - Hother Equipment Failure: - Hother Equipment Fai		
- Other Most recent year conducted: - Other Most recent year conducted: - Describs: G6 - Equipment Failure - only one sub-cause can be selected from the sheded left-hand column Equipment Failure - Sub-Cause - If Matfunction of Control/Ratief Equipment: - Specify: (seelect all that apply) Control Valve - Instrumentation - SCADA - Communications - SCADA - Check Valve - Check Valve - Check Valve - Power Failure - Stope(Control Fitting - SSD System Failure - Other - If Other - Describe: - If Pump or Pump-related Equipment: - Specify: - If Other - Describe: - If Threaded Connection/Coupling Failure: - Specify: - If Non-threaded Connection Failure: - If Non-threaded Connection Failure: - Specify: - If Other - Describe: - If Other Equipment Failure: - Specify: - If Other Equipment Failure: - Specify: - If Other Equipment Failure: - Specify: - If Other Equipment Failure: - Specify: - If Other Equipment Failure: - Specify: - If Other Equipment Failure: - Specify: - If Other Equipment Failure: - Specify: - If Other Equipment Failure: - Specify: - If Other Equipment Failure: - Specify: - If Other Equipment Failure: - The Other Equipment Failure sub-cause is selected Additional factors that contributed to the equipment failure: (select all that apply) - Excessive vibration - Overpressulzation - No support or loss of support - Manufacturing described: - Namathod itoms (different manufacturer for tubing and tubing fittings) - Described own of soft goods due to competibility issues with transported commodity - Valve valut or valve can contributed to the release - Alarnykstatus failure - Missinghamet - Thormal stress - Other - If Other, Describe:		1 1 1 2 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
- Other Most recent year conducted: Doscribs: G6 - Equipment Failure - only one sub-cause can be selected from the shaded left-hand cotiumn Equipment Failure - Sub-Cause: - If Matfunction of Control/Relief Equipment: - Specify: General at that apply) Control Valve - Instrumentation - SCADA - Communications - Block Valve - Check Valve - Check Valve - Relief Valvo - Power Failure - Stopple/Control Fitting - If Other - Describe: -		
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- 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:		
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- Valve vault or valve can contributed to the release - Alarm/status failure - Misalignment - Thermal stress - Other - If Other, Describe:		
- Alarm/status failure - Misalignment - Thermal stress - Other - If Other, Describe:		
- Misalignment - Thermal stress - Other - If Other, Describe:		
- Thermal stress - Other - If Other, Describe:	- Alarm/status failure	
- Thermal stress - Other - If Other, Describe:	- Misalignment	
- Other - If Other, Describe:		
- If Other, Describe:		
G7 - Incorrect Operation - only one sub-cause can be selected from the shaded left-hand column	- ii Oglol, Dossitus.	
	G7 - Incorrect Operation - only one sub-cause can be selected from	the shaded left-hand column

Incorrect Operation - Sub-Cause:		
- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow		
1. Specify:		
- If Other, Describe:	<u> </u>	
- If Other Incorrect Operation		
2. Describe:		
Complete the following if any incorrect Operation sub-cause is selected	d.	
3, Was this Accident related to (select all that apply): -		
- Inadequate procedure		
- No procedure established		
- Fallure to follow procedure		
- Other:		
- If Other, Describe:		
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 fro Other Accident Cause - Sub-Cause:	om the shaded left-hand column	
- If Miscellaneous:		
1. Describe:		
- If Unknown:		
2. Specify:		
PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT		
5/20/16 00:35hrs PT the 24" pipe segment from Tracy to Windmill Farms ruptured. The pipeline Houston Control Center SCADA detected an increase in flow rate and drop in discharge pressure. The Pump Station immediately shutdown on low suction. The Controller took action to shutdown the entire pipeline system and isolate the pipeline. Notifications were made to the field supervisor, the Control Center Supervisor. Personnel were sent to the area of the pump station to locate the exact location of the release.		
PART I - PREPARER AND AUTHORIZED SIGNATURE		
Preparer's Name	Richard Klasen	
Preparer's Title	Regulatory Specialist	
Preparer's Telephone Number		
Preparer's E-mail Address		
Preparer's Facsimile Number		
Authorized Signer Name	Deborah Price	
Authorized Signer Title	Pipeline Ops Regulatory Manager	
Authorized Signer Telephone Number	-	
Authorized Signer Email		
Date	06/15/2016	

Final Report

Metallurgical Analysis of May 20, 2016 Rupture on Tracy to Windmill Portion of San Pablo Bay Pipeline System

Shell Pipeline Company Houston, Texas

Report No.: OAPUS311MPHB (PP158491)

November 7, 2016

Metallurgical Analysis of May 20 2016 Rupture on Tracy to Windmill Portion of San Pablo Bay Pipeline System

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Keywords

Rupture, seam weld, HAZ, ID surface, fatigue, environmental cracking

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Executive Summary

Shell Pipeline Company, LP (*SPLC*) retained Det Norske Veritas (U.S.A.), Inc. (*DNV GL*) to perform a metallurgical analysis of a rupture that occurred on the Tracy to Windmill portion of the San Pablo Bay Pipeline System. The failure occurred on May 20, 2015 in Tracy, California, approximately 4,068 feet from the nearest upstream (U/S) pump station; the Tracy Pump Station.

Tracy to Windmill is part of a 177.77 mile long segment of the San Pablo Bay Pipeline System consisting of 20-inch and 24-inch diameter pipe that originates at the Coalinga Station in Coalinga, CA and terminates at the Shell Martinez Refinery in Avon, CA. The Coalinga to Avon segment was originally installed in 1967.

In 1989, three portions, totaling 12.55 miles, of the pipeline were replaced with 24-inch diameter by 0.260 inch wall, API 5LX Grade X60 double submerged arc-welded (DSAW) line pipe manufactured by Armco Steel in Houston, TX. The Tracy to Windmill portion, which is where the failure occurred, consists of 3.05 miles of the 12.55 miles of Armco line pipe installed in 1989.

Historical information indicates that the Armco line pipe used to construct the 12.55 miles of pipeline was stored for approximately 7 years following manufacturing and then was shipped from the northeastern United States to Coalinga, California for construction. The 12.55 miles of the replaced pipeline were externally coated with a 3-layer coating, comprised of fusion-bonded epoxy (FBE) on the pipe surface, a mastic coating, and an external polyolefin wrap. The pipeline has an impressed current cathodic protection (CP) system.

The pipeline operates in heavy crude service, with temperatures up to 180°F. On the day of the failure, the maximum allowable operating pressure (MAOP) of the pipeline was 936 psig, which corresponds to 72.0% of the specified minimum yield strength (SMYS). The segment operated with aggressive pressure cycling in the period leading up to the failure. The pressure at the time and location of the failure was estimated to be 665 psig, which corresponds to 51.2% of SMYS.

The most recent hydrostatic pressure test prior to the failure was performed in 1990. A minimum pressure of 1181 psig (90% of SMYS) was held for four hours. The most recent in-line inspections (ILIs), using a circumferential magnetic flux leakage (CMFL) tool and an ultrasonic testing crack detection (UT/CD) tool, were performed on 12/03/2015 and 12/04/2015, respectively. No anomalies in the failed joint were reported in the CMFL final report issued on 03/07/2016 or in the UT/CD final report issued on 05/02/2016.

A pipe section that contained the rupture was delivered to DNV GL for metallurgical analysis. The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

The results of the metallurgical analysis indicate that the pipe joint ruptured at a fatigue crack that initiated at the toe of the DSAW seam weld on the inside surface of the pipe. Likely contributing factors include the peaked geometry of the failed pipe joint at the seam weld that introduced a bending stress, corrosion micro-pits on the ID surface that provided initiation sites, aggressive pressure cycling of the pipeline, and possibly an environmental effect on crack growth.

The fatigue crack initiation and propagation most likely occurred while in service. However, transit fatigue during transportation of the pipe cannot be ruled out as a contributing factor. Shell reported to have records of rail transportation per API 5L1 for the first portion of the journey, from Houston Texas to the northeast of the U.S. For the second portion of the journey, from the northeast to Coalinga California, verbal information indicates that API 5L1 would have been specified per industry norms, but written records have not been located.

The following steps were performed for this analysis:

- · Visual inspection and photography,
- Removal of remnant coating still adhered to the pipe,
- Dimensional measurements,
- Magnetic particle inspection (MPI),
- Removal, cleaning and visual inspection of samples,
- Light microscopy and scanning electron microscopy of fracture surfaces (SEM),
- Examination of metallographically prepared cross-sections,
- Energy dispersive spectroscopy (EDS),
- Mechanical testing (duplicate tensile tests and full Charpy V-notch curves),
- Chemical analysis of steel samples, and
- Failure pressure calculations using CorLAS[™].

Summary of observations:

- The pipe joint that ruptured contained several types of mill anomalies at the long seam weld, including peaking, weld overlap, and weld undercut.
- The fatigue crack at the rupture origin was 6.96 inches long and initiated from small (50-100 micron) pits along the internal toe of the DSAW. There was no evidence of a pre-existing weld-type defect at this location. The long-seam weld was located at the 3:26 o'clock orientation.
- MPI testing revealed other crack-like flaws on the pipe joint that failed, at approximately 2.7 feet D/S and 7.7 feet D/S of the rupture origin along the internal surface of the DSAW. The largest feature (MPI Indication 1a) was 4.25 inches in length and 0.125 inches depth (48.1% of 0.260 inches nominal wall thickness) at the deepest location.
- Qualitative spot testing indicated the presence of sulfides on the fracture surface at the failure origin, which is not uncommon in crude oil pipelines.
- Cross-sections showed that cracks at weld toes at locations away from the rupture were filled with sulfur-containing products, which is not uncommon in crude oil pipelines.
- There was no evidence of external corrosion on the pipe section.
- No MPI indications were identified on portions of the longitudinal seam weld of the U/S or D/S joints that were examined; 1.58 feet of the U/S joint and 1.79 feet of the D/S joint.
- The tensile properties of the failed joint and the joints U/S and D/S of the failed joint meet the tensile requirements for API 5LX Grade X60 line pipe steel for the estimated vintage of the pipe (1980).
- The Charpy V-notch (CVN) properties of the base metal of the failed joint are typical for the vintage and grade of line pipe steel. The seam weld HAZ had better fracture toughness properties than the base metal, with a slightly higher upper shelf impact energy and lower 85% FATT temperature.
- The composition of the base metal of the failed joint and the joints U/S and D/S of the failed joint meets requirements for API 5LX Grade X60 line pipe steel for the estimated vintage of the pipe (1980).
- The microstructures of the pipe joints are typical for the vintage and grade of line pipe steel.
- The estimated failure pressure using mechanical properties of the heat affected zone and the flaw profile that ruptured is 664 psig, which is close to the calculated pressure at the failure location and time of failure (665 psig).

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Metallurgical Analysis of May 20, 2016 Rupture on Tracy to Windmill Portion of San Pablo Bay Pipeline System

List of Acronyms

BDWTT Battelle Drop Weight Tear Test

CCW Counter Clockwise (orientation)

CMFL Circumferential Magnetic Flux Leakage (tool)

CP Cathodic Protection

CVN Charpy V-Notch (impact testing)

CW Clockwise (orientation)

D/S Downstream

DSAW Double Submerged Arc-Welded (pipe)

EDS Energy Dispersive Spectroscopy

ERW Electric Resistance Welded (pipe)

FATT Failure Appearance Transition Temperature

FBE Fusion-Bonded Epoxy

GW Girth Weld

HAZ Heat Affected Zone

HV Vickers Hardness

ID Inside Diameter (surface)

ILI In-Line Inspection

MAOP Maximum Allowable Operating Pressure

MPI Magnetic Particle Inspection

OD Outside Diameter (surface)

SEM Scanning Electron Microscope

SMYS Specified Minimum Yield Strength

SSC Sulfide Stress Cracking

U/S Upstream

UT/CD Ultrasonic Testing Crack Detection (tool)

UTS Ultimate Tensile Strength

wt Wall Thickness YS Yield Strength

1.0 BACKGROUND

Shell Pipeline Company, LP (*SPLC*) retained Det Norske Veritas (U.S.A.), Inc. (*DNV GL*) to perform a metallurgical analysis of a rupture that occurred on the Tracy to Windmill portion of the San Pablo Bay Pipeline System. The failure occurred on May 20, 2015 in Tracy, California, approximately 4,068 feet from the nearest upstream (U/S) pump station; the Tracy Pump Station.

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The pipeline operates in heavy crude service, with temperatures up to 180°F. On the day of the failure, the maximum allowable operating pressure (MAOP) of the pipeline was 936 psig, which corresponds to 72.0% of the specified minimum yield strength (SMYS). The segment operated with aggressive pressure cycling in the period leading up to the failure. The pressure at the time and location of the failure was estimated to be 665 psig, which corresponds to 51.2% of SMYS.

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A pipe section that contained the rupture was delivered to DNV GL for metallurgical analysis:

• a 29.81 foot long pipe section that contains the 26.44 feet long failed joint, 1.58 feet of the upstream U/S joint, and 1.79 feet of the downstream (D/S) joint.

The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

2.0 TECHNICAL APPROACH

The procedures used in the analysis were in accordance with industry-accepted standards. Five of the general standards governing terminology, specific metallographic procedures, mechanical testing, and chemical analysis used are as follows:

- ASTM E7, "Standard Terminology Relating to Metallography."
- ASTM E3, "Standard Methods of Preparation of Metallographic Specimens."
- ASTM E8, "Test Methods for Tension Testing of Metallic Materials."
- ASTM E23, "Standard Test Methods for Notched Bar Impact Testing of Metallic Materials."
- ASTM A751, "Standard Test Methods, Practices, and Terminology for Chemical Analysis of Steel Products."

The following steps were performed for this analysis. The pipe section was visually inspected and photographed. Wall thicknesses and diameters were measured on the ends of the pipe section where coating was removed and there was no measurable corrosion. Remnant coating, which still adhered to the pipe, adjacent to the failure location, was removed. Magnetic particle inspection (MPI) was performed on the internal pipe surfaces at areas adjacent to the rupture location, as well as along the internal surface of the longitudinal seam welds associated with the pipe joints. No MPI was deemed necessary on the external pipe surfaces because the failure initiated from the inside. Prior to MPI, the regions examined were cleaned with a degreaser (PreSolve®).

The fracture surfaces were cleaned with a degreaser and optically examined, and photographed. The length and depths of a pre-existing flaw on the fracture surface were measured to produce a flaw profile. Fracture surface samples were removed from the suspected rupture origin on the clockwise (CW) fracture surface, cleaned with a degreaser and methanol, and examined at high magnifications in a scanning electron microscope (SEM) to document the fracture morphology. Transverse cross-sections were removed from two areas at the suspected rupture origin and from two linear indications identified approximately 2.7 feet and approximately 7.7 feet downstream of the rupture origin by MPI.

In addition, transverse cross-sections were removed from the longitudinal seam weld of the ruptured joint and U/S and D/S joints at areas away from the rupture or other MPI indications. The cross-sections were mounted, polished, and etched; see Figure 1 for locations. Light photomicrographs were taken to document the fracture morphology and steel microstructure. SEM with energy dispersive spectroscopy (EDS) was performed on metallographically prepared cross-sections of the MPI-indications, to analyze for the presence of sulfur and other elements. Micro-hardness testing (Vickers - 500 g load) was performed on the metallographic mounts to determine hardness.

Mechanical (duplicate tensile tests and full Charpy V-notch [CVN] curves) testing was performed on specimens removed from the base metal and seam weld of the pipe joint that ruptured to determine the tensile and fracture toughness properties. The Charpy specimens across the seam weld were notched in the heat-affected zone (HAZ) of the same weld toe associated with the rupture. Mechanical (duplicate tensile tests) testing was also performed on specimens removed from the base metal of the U/S and D/S joints to determine tensile properties. Chemical analyses were performed on steel samples removed from the pipe joint that ruptured and the U/S and D/S joints to determine the compositions.

CorLASTM calculations were performed to estimate the failure pressure of the pipe joint that ruptured based on the pipe geometry, measured mechanical properties, and the measured flaw profile.¹ These values were compared with the calculated pressure at the failure location at the time of the failure.

3.0 RESULTS AND DISCUSSION

3.1 Optical Examination

Figure 2 shows a photograph of the pipe section in the as-received condition. The pipe section was wrapped with plastic and duct tape, with the failure location facing up during transit. Figure 3 is a photograph of the pipe section near the rupture after removal of the protective wrappings. The pipe section was 29.81 feet in length and contained reference markings identifying flow direction and clock orientation. It contained the 26.44 feet long failed joint, 1.58 feet of the U/S joint, and 1.79 feet of the D/S joint.

A stencil on the external surface of the polyolefin wrap "ERW, 24 OD X .260" WT 66LBS/FT", towards the U/S end of the failed joint, suggests that the pipe section is comprised of 24-inch diameter by 0.260-inch wall line pipe steel with a longitudinal electric resistance

¹ CorLAS™ is a computer program developed by CC Technologies Systems, Inc., which is now Det Norske Veritas (U.S.A.), Inc., to evaluate crack-like flaws in pipelines based on inelastic fracture mechanics.

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welded (ERW) seam. However, the morphology of the longitudinal seam weld on the failed pipe section is consistent with a DSAW seam, not an ERW seam.

Diameters and wall thicknesses were measured on the U/S and D/S ends of the pipe section (U/S and D/S joints). The diameter measurements were made after locally removing the three-layer coating. The diameter of the U/S joint was 24.2 inches between the 12 and 6 o'clock orientations, and 23.9 inches between 3 and 9 o'clock orientations, indicating some ovality. The diameters of the D/S joint were both 24.1 inches, indicating no measurable ovality, as shown in Table 1. The diameters meet API 5LX tolerances² for 24-inch nominal diameter pipe.

Wall thicknesses were measured at the 12, 3, 6, and 9 o'clock orientations at areas with negligible corrosion and no coating near the failure location, at the U/S and D/S ends of the failed joint, on the U/S joint, and on the D/S joint; see Table 2 for details. The wall thickness values ranged between 0.272 inches and 0.296 inches, with the exception of the area immediately adjacent to the failure at the 3 o'clock orientation, where the wall thickness was 0.251 inches due to local yielding (necking) at the rupture area. The average wall thickness of the ruptured joint, U/S joint, and D/S joint are 0.276 inches (excluding the failure area), 0.288 inches, and 0.282 inches, respectively. The average wall thickness values and the individual wall thickness values away from the rupture area meet API 5LX tolerances for a nominal wall thickness of 0.260 inches.

Table 3 contains a summary listing of the various features found on the pipe section, as described further in the text below, together with the locations from which cross-section samples ("Mounts") were prepared, as described in Sections 3.3 and 3.4. The rupture was 3.77 feet in length, consisting of a symmetric fish-mouth failure that initiated at or near the toe of the DSAW at the 3:26 o'clock orientation, on the clockwise (CW) side of the seam weld. The U/S and D/S ends of the rupture were located at 14.17 feet and 17.94 feet, respectively, from the U/S GW as shown in Figure 3. The maximum opening was 4.5 inches (0.38 feet), approximately 16.13 feet from the U/S GW.

The crack path was relatively smooth in appearance, located at the toe of the DSAW for approximately 7 inches (15.88-16.46 feet from U/S GW) of the rupture length, and then transitioning off of the toe in either direction, upstream and downstream. The coating on either side of the fracture, within 1-3 inches, was locally disbonded; however, the coating on the remaining portions of the pipe section was in good condition and well adhered to the pipe steel. There was no evidence of external corrosion along the areas of disbonded

² API 5LX (23rd Ed., March 1980): "Out-of-Roundness. For pipe larger than 20 in., and for a distance of 4 in. (101.6 mm) from the ends of the pipe, the maximum outside diameter shall not be more than 1 per cent larger than specified, and the minimum outside diameter shall not be more than 1 per cent smaller than specified."

coating, suggesting that the local disbondment was a result of plastic deformation of the pipe material during the rupture event.

3.2 Magnetic Particle Inspection

The pipe section was cut longitudinally to facilitate examination of the internal surfaces and MPI of the longitudinal seam welds of the failed joint and U/S and D/S joints. There was no evidence of internal corrosion. Two areas with indications were identified along the internal surface of the failed joint at the toe of the seam weld. A summary of the locations and dimensions of these indications is presented in Table 4.

Area 1 included MPI Indication 1a (CW) and MPI Indication 1b (CCW), both located approximately 2.7 feet D/S of the rupture origin (~18.8 feet from U/S GW), see photograph in Figure 4. The indications appear as crack-like features along the toe of the seam weld. MPI Indication 1a appears as a crack-like feature between 18.62-19.05 feet from the U/S GW, at the weld toe on the CW side of the seam weld. MPI Indication 1b also appears as a crack-like feature, and is located between 18.70-19.12 feet from the U/S GW, at the weld toe on the CCW side of the seam weld. Two 3/8 inch long areas of weld overlap are also apparent 18.8 ft from the U/S GW.

Area 2 contains MPI Indication 2 (CW), located 7.7 feet D/S of the rupture (23.83 feet from the U/S GW), see photograph in Figure 5. The indication appears as a small (0.25 inch long) dimple of missing weld metal (undercut), resulting in a notch at the toe of the seam weld.

3.3 Fractographic Examination

3.3.1 Rupture Location

Figure 6 is a photograph of the CW side of the fracture surface of the rupture before cleaning. A flaw originating from the pipe inside (ID) surface is evident on the fracture surface 15.88-16.46 ft from the U/S GW. That area (CW side only) was cut out and cleaned with a degreaser and methanol. Figure 7 shows a photo-collage of the suspected rupture origin after cleaning. The surface is dull and gray in color, with slightly lighter areas near the internal surface. The pre-existing flaw at the ID surface has a semi-elliptical shape, with the suspected rupture origin located at approximately 16.13 ft from the U/S GW. The origin location was identified based on the overall flaw shape and fracture surface coloration.

The fracture surface was categorized into three regions: **Region 1** – flat, slightly lighter gray in appearance, located near the internal surface, and perpendicular to the internal and

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external surfaces; **Region 2** – rough in texture, darker gray in appearance, located near mid-wall, and perpendicular to the internal and external surfaces; **Region 3** – rough in texture, darkest gray in appearance, located near the external surface, and at an oblique angle with respect to the internal and external surfaces. The pre-existing (prior to failure) flaw consists of Region 1 and Region 2.

These three regions are shown in the optical photomicrograph in Figure 8, taken approximately 16.1 feet from the U/S GW. Region 1 contains multiple crack fronts on various planes that are separated by ratchet marks³. This macro-scale morphology is consistent with multiple crack initiation sites. At higher magnification, Figure 9, small pits can be seen along the internal surface, possibly serving as crack initiation sites. These pits might have formed during the long storage period of the line pipe prior to construction or could have formed in service.

Region 2 and Region 3 are macroscopically rougher than Region 1. The oblique angle of Region 3 with respect to the internal and external pipe surfaces is consistent with a shear lip, indicative of ductile overload. Except for the discoloration in the described regions, the fracture surface did not have distinct beach marks⁴, which are commonly associated with the growth of a fatigue crack.

Figure 10 is an SEM image of an area of the fracture surface from within the suspected failure origin, approximately 16.1 feet from the U/S GW. The orange dashed lines indicate the interfaces between Regions 1/Region 2, and Region 2/Region 3. Note the rough woody morphology of Region 2.

Figure 11 is an SEM image of the fracture surface within Region 1. Large steps and cracks are visible parallel to the ID pipe surface. Figure 12 is a higher magnification SEM image of the fracture surface immediately adjacent to the ID pipe surface, where a pit of approximately 100 microns wide by 50 microns deep is visible, similar to the pits discussed in the optical photomicrograph in Figure 9. Figure 13 shows another high magnification SEM photomicrograph taken within Region 1 adjacent to the internal surface. The image shows fatigue striations⁵ that emanate from the internal surface. Figure 14 is an SEM image of the fracture surface within Region 2. A stair-stepped, "woody" topography with little evidence of ductility was evident through much of Region 2, which can be indicative of

³ Ratchet marks: Macroscopic features that originate when multiple cracks, nucleated at different points, join together, creating steps on the fracture surface.

⁴ Beach marks: Macroscopic concentric marks that are a result of successive arrests or decrease in the rate of fatigue crack growth due to a temporary load drop, or due to an overload that introduces a compressive residual stress field ahead of the crack tip.

⁵ Fatigue striations: Microscopic features (that may be) visible with the aid of a scanning electron microscope, resulting from the successive blunting and re-sharpening of the crack tip in ductile materials, and that appear as fine, parallel lines perpendicular to the direction of crack growth.

intermittent crack growth. Some secondary cracking is also visible, possibly related to the different microstructure of the weld HAZ near mid-wall, or related to an environmental effect on crack growth that caused crack branching. At higher magnification, the morphology consisted of bands of ductile overload separated by bands that exhibited little to no cohesion with the surrounding material, and secondary cracking; refer to Figure 15. Figure 16 and Figure 17 are SEM images confirming ductile overload failure in Region 3.

Figure 18 and Figure 19 show detailed flaw depth measurements taken of Region 1 and Region 2 on the CW side fracture surface. Wall thickness measurements were also taken along the fracture surface, and the measurements ranged between 0.226 and 0.251 inches, showing that the metal in the rupture area yielded from its nominal wall thickness of 0.260 inches. Figure 20 is a plot of flaw depth versus distance from the U/S GW. The measured flaw associated with Region 1 is indicated by the red line, while Region 2 is indicated by the green line. The figure shows that the pre-existing (prior to rupture) flaw length was approximately 7.0 inches, and that the maximum depth of Region 1 is 0.097 inches and the maximum depth of the combined flaw (Region 1 + Region 2) is 0.210 inches; 37.3% and 80.8% of the 0.260 inches nominal wall thickness, respectively.

3.3.2 Testing for Sulfides and Carbonates - Primary Fracture Surface

Spot testing, using a 1M HCl solution, was performed on the CCW side of the fracture surface (no cleaning) to test for the presence of sulfides and carbonates. A color change from white to brown in lead-acetate test paper is a positive indicator of sulfides, while vigorous bubbling is a positive indicator for carbonates. The fracture surface tested positive for the presence of sulfides and negative for carbonates. The sulfides likely deposited on the fracture surface by a corrosion mechanism and might have played a role in the fatigue crack growth. The absence of carbonates indicates that CO_2 likely did not play a role in the corrosion process.

3.3.3 MPI Indications

Prior to breaking open MPI Indication 1a, a piece was removed from its center for cross-section metallography (Mount 1), which is described later. After that, the remaining U/S and D/S portions of the pipe piece containing MPI Indication 1a were submerged in liquid nitrogen and struck with a brass mallet to break open the flaw for fractographic examination. The created fracture was not cleaned. Figure 21 is a photograph of the flaw that (after removing the metallographic section) measured approximately 4.25 inches in length. Figure 22 is a close-up view of the center portion of the flaw, showing the maximum depth is approximately 0.125 inches (48.1% of 0.260 inches nominal wall

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thickness). The flaw has a dark appearance and a staggered fracture path on multiple parallel planes.

Figure 23 is a close-up view of the flaw, which has two distinct colored regions, a black region (Region 1) adjacent to the pipe ID surface and a brown region (Region 2) near mid-wall. The black Region 1 is located adjacent to the internal surface and resembles Region 1 of the pre-existing flaw located at the rupture origin, as described above, with an overall relatively flat appearance and ratchet marks along the ID to indicate multiple initiation planes. White residue from the MPI testing is present in Region 1, indicating that the crack was open to the ID surface of the pipe prior to fracture. The brown Region 2 resembles Region 2, with a stair-stepped, "woody" fracture appearance. Oily residue is present in both Regions A and B, showing that both regions were present during service when crude oil could leach in.

MPI Indication 1b and MPI Indication 2 were not broken open, because the metallographic cross-sections showed no cracks were present, as will be discussed in Section 3.4.3.

3.3.4 Testing for Sulfides and Carbonates – MPI Indication 1a

Spot testing, using a 1M HCl solution, was performed on the CCW side of the fracture surface (no cleaning) to test for the presence of sulfides and carbonates. The fracture surface tested positive for the presence of sulfides and negative for carbonates.

3.4 Metallographic Examination

This section describes the observations from metallographic cross-section samples taken from the rupture origin location (Mount M5 and Mount M6), from reference locations (Mount M7, Mount M3, and Mount M4), and from MPI Indications (Mount M1 and Mount M2), as summarized in Table 6 and shown in Figure 1.

3.4.1 Rupture Origin

Figure 24 and Figure 25 are photographs of transverse metallographic sections (Mount M5 and Mount M6) that were removed from across the fracture surface at approximately 16.13 feet and 16.33 feet from the U/S GW, respectively. Mount M5 was removed from the likely rupture origin, and Mount M6 was removed 2.4 inches (0.2 feet) D/S of the likely rupture origin. The locations are shown in Figure 1 and Figure 6. The morphology of the weld is consistent with DSAW with the final pass at the OD pipe surface.

Figure 26 shows typical examples of the microstructures of the base metal (Figure 26a), the weld fusion metal near the ID surface (Figure 26b), the HAZ metal near the ID weld toe that failed (Figure 26c), and the HAZ metal near mid-wall (Figure 26d). The base metal consists

of equi-axed ferrite (white grains) and pearlite (black grains) and, within that structure, some rounded and elongated inclusions are present. This microstructure is consistent with the vintage and grade of the steel. The weld fusion metal of the weld bead at the ID pipe surface also has equi-axed grains, but contains visually more ferrite than the pipe base metal. The microstructure of the HAZ near the ID weld toe shows angular grain morphology, known as Widmanstätten structure. At the mid-wall of the pipe wall thickness, the HAZ consists of ferrite and pearlite with a finer grain size than the base metal. These microstructures are all typical of DSAW welds in carbon steel line pipe.

Both mounts appear very similar, with the inside and outside weld passes located on the center of the bond line (not offset laterally⁶ from one another), and with the primary crack extending from the CW toe on the internal surface through the HAZ of the weld to the OD pipe surface near the weld toe. Note that the crack at the OD pipe surface in both mounts is at an oblique angle with respect to the pipe surface, which is consistent with final failure by ductile shear. In both mounts, the weld appears to be peaked or tented as a result of the approach angle between the CW and CCW plate edges; further discussion is provided in Section 3.4.6.

Figure 27 and Figure 28 are montages of photomicrographs showing the cross-section through the fracture surfaces on the CW side of the seam weld of Mount M5 (failure origin) and Mount M6, respectively. Mount M6 revealed similar features as Mount M5, and is therefore not separately discussed further here. Both cross-sections show that the fracture plane is radial⁷ through 70%-80% of the wall thickness and then transitions to a 45 degrees angle near the OD pipe surface. The 45 degree angle is consistent with a shear lip, associated with ductile overload, and correlates with Region 3 previously defined above. Region 2 is rougher than Region 1 or Region 3 and some secondary cracks are present in Region 2. As mentioned earlier, crack branching at the pipe mid-wall (rougher Region 2) may be a result of microstructural differences in the weld and/or an environmental effect.

Figure 29 is a photomicrograph showing the location of fracture initiation at the immediate edge of the internal weld bead and the HAZ. The fracture path is straight, consistent with fatigue identified in Region 1 in the SEM examination.

Figure 30 is a photomicrograph showing the rough fracture path consistent with the stepwise characteristics of Region 2 identified during the SEM examination. Secondary cracks are present along the fracture surface in this region. The secondary cracks are relatively straight.

^{6 &}quot;Out-of line weld bead (off-seam weld) shall not be cause for rejection provided complete penetration and complete fusion have been achieved as indicated by nondestructive examination." API 5LX, 23rd Edition, 1980.

⁷ Approximately perpendicular to the pipe walls.

Figure 31 is a photomicrograph from the area identified as Region 3, showing elongated and deformed grains in the 45 degree plane, which is consistent with shear ductile overload.

Figure 32 shows photomicrographs in the as-polished and as-etched conditions of an area on the ID surface of Mount M5, in the base metal away from the rupture area. A micro-pit (100-200 micron size) filled with corrosion product is visible. This particular corrosion product was not analyzed for composition, but EDS analyses of other scales indicate it is likely a Fe-O-S compound; refer to Section 3.4.4. This image is a typical example of several micro-pits that were observed in the cross-sections. No cracking was associated with this or other micro-pits visible in the base metal areas of the cross-sections.

Figure 33 is a montage of photomicrographs of the CCW side of the weld in Mount M6 (opposite side of the weld at the rupture location). A small crack is apparent from the weld toe into the HAZ. Two similar cracks are present at the toe of the seam weld on the CCW side in Mount M5, and Figure 34 shows photographs of these cracks in the as-polished and as-etched conditions. The cracks in Mounts M5 and M6 are approximately 200 microns deep, which is consistent with them being continuous along the seam weld and being only 2.4 inches apart. The cracks originate from the pipe ID surface, each in an area with a micro-pit that is filled with corrosion product. As previously discussed, these pits might have formed during the long storage period of the line pipe prior to construction or could have formed in service. Both cracks are branched and have a transgranular crack path into the HAZ. The presence of corrosion products and crack branching are characteristics that may be associated with an environmental degradation mechanism.

3.4.2 Reference Locations

Metallurgical cross-sections were removed from across the seam weld of the failed pipe joint (away from the rupture; Mount M7), the U/S joint (Mount M4), the D/S joint (Mount M3). Photographs of the mounted cross-sections are presented in Figure 35, Figure 36, and Figure 37, respectively. There was no evidence of cracking in the welds or base metal in any of these reference mounts.

3.4.3 MPI Indications

Figure 38 and Figure 39 are photographs of the metallographic cross-sections, Mount M1 and Mount M2, respectively, removed from the locations marked in Figure 4 (MPI Indications 1a/1b and Figure 5 (MPI Indication 2).

Figure 40 is a photomicrograph of the area associated with MPI Indication 1a. At this location, a crack from the ID pipe surface, at the CW side of the seam weld, is present with

a depth of approximately 0.119 inches (45.8% of 0.260 inches nominal wall thickness). The crack path close to the ID surface is straight without crack branching (refer back to Region 1 in Figure 23), and, further into the metal, transitions to a tortuous path where crack branching is apparent (refer back to Region 2 in Figure 23). Figure 41 shows a higher magnification photomicrograph of the crack tip, where extensive crack branching is apparent in the fine-grain microstructure of the HAZ. The inset photo in this figure shows a close-up view of the transgranular morphology (red circles) at the crack tip.

Figure 42 is a photomicrograph of the area associated with MPI Indication 1b. At this location, weld overlap is apparent. The filler metal of the weld bead extends approximately 3 mm (3000 microns) over the pipe ID surface on the CCW side of the seam weld. While the overlap creates a sharp transition at the weld toe, no cracking is apparent at the tip of that transition.

Figure 43 is a montage of photomicrographs of the area associate with MPI Indication 2. A notch of approximately 0.060 inches depth (23.1% of 0.260 inches) nominal wall thickness) is present where weld undercut has occurred. Figure 44 shows photomicrographs, in the as-polished and as-etched condition, of a 0.012 inches deep crack (4.6% of 0.260 inches nominal wall thickness) that initiated from this notch. Similar to the cracks found at the seam weld toe on the CCW side of Mount M5 and Mount M6 at the rupture location, the crack at MPI Indication 2 initiated from a micro-pit that is filled with corrosion product (which was not removed during the cleaning process of the sample preparation). The crack morphology is transgranular and branching that extends into the HAZ microstructure suggests an environmental damage mechanism.

3.4.4 EDS Analysis of Cracks and Corrosion Products

Scanning electron microscopy with EDS was performed on the metallographically prepared cross-sections of the crack associated with MPI Indication 1a (Mount M1) and the crack and pit with corrosion products associated with MPI Indication 2 (Mount M2), to analyze for the presence of sulfur and other elements.

Figure 45 shows a composition SEM/EDS image of the crack tip associated with MPI Indication 1a, where the green color indicates areas where sulfur was detected. In this figure, approximately one-third of the crack depth is visible. The imaged crack tip is approximately 0.043 inches (1100 microns) of the overall crack depth of 0.119 inches. On Mount M1, no EDS analysis was performed in the area of the crack mouth near the inside pipe surface.

Figure 46 shows EDS elemental maps for the elements iron (Fe), oxygen (O), manganese (Mn), sulfur (S), silicon (Si), and carbon (C). These images reveal that oxygen- and sulfur-containing corrosion products are present within the crack, all the way to the tip of the crack. The likely source of the elements sulfur and oxygen is the crude oil in the pipeline. Other detected sulfur within the HAZ metal coincides with inclusions visible in the cross-section and also with manganese in the elemental maps, thus indicating that those inclusions are most likely MnS compounds.

Figure 47 shows the locations where EDS analyses were performed of the corrosion product and base metal at the ID surface of MPI Indication 2. The results are summarized in Table 5, revealing that the corrosion product has high concentrations of sulfur (27-32 wt.%), some oxygen (7-11 wt.%), with the balance predominantly iron (55-65 wt.%) (EDS #1, EDS #2, and EDS #3) when compared with the base metal (EDS#4).

Figure 48 shows a composition SEM/EDS image and Figure 49 shows EDS elemental maps of the corrosion-filled pit at the notch and the crack located at the CCW toe of the weld at the ID pipe surface. Sulfur was detected in the corrosion product, inside the crack along the entire crack path, and MnS inclusions were located within the metal. As with the previous MPI indication, the presence of sulfur suggests an environmental component to the damage mechanism.

3.4.5 Hardness Testing

Vickers micro-hardness testing was performed, using a 500 g load, on Mounts M5 and M6 (rupture), Mounts M3, M4 and M7 (D/S, U/S, and failed joints), Mount M1 (MPI Indications 1a/1b) and Mount M2 (MPI Indication 2). The test locations and results are summarized in Figure 50, in Figure 51, Figure 52, and Figure 53, respectively.

For the ruptured area of the failed joint, the hardnesses in the HAZ on the CW side of the seam weld, adjacent to Region 1 and Region 2 (Locations 1, 2, 3, 4, 5, 8) were measured. The hardness values ranged between 190.3 and 218.1 HV (Mount M5) and 183.4 and 218.8 HV (Mount M6). The maximum hardness measured was in the base metal of Mount M5, 227.8 HV. 225.0 HV (HAZ in Mount M7), 235.1 HV (weld metal, Mount M4), 213.5 HV (weld metal, Mount M3), were the maximum values measured for the three joints.

The range of hardness measured on the failed side of the weld was very similar to those measured on the unfailed side of the weld. The hardness values measured on the unfailed welds were similar to those measured in the failed welds. The hardness values near the

MPI Indications were similar to those in weld areas without MPI Indications. All these observations show that hardness was not a contributing factor to the failure.

International standards⁸ provide guidance for the application of materials exposed to service conditions that promote sulfide stress cracking (SSC). All of the measured values are less than the maximum allowable hardness of 250 HV for weld roots, base metal, and HAZ. Therefore, any environmental component to crack growth is more likely related to corrosion fatigue than SSC.

3.4.6 DSAW Measurements

The cross-sections removed from the ruptured joint exhibited a slightly more peaked appearance than those in the U/S and D/S joints. This is a local discontinuity to the roundness of the pipe that can not only affect how the sensors of an ILI tool contact the pipe, but also how stresses in the pipe develop when it is pressurized. Under normal operation, the internal pressure of the pipe will strain the pipe to a rounded condition, generating an additional tensile bending stress at the internal surface. This, in combination with the geometry of the weld toe, can produce locally high stresses.

Measurements were made on Mounts M1-M7 to quantify the angle between the plate edges on the CW and CCW sides of the seam weld. The lower the angle (farther away from the ideal 180°), the higher the tensile bending stress when the pipe is pressurized. The results are summarized in Table 6, with additional photographs provided in Appendix A. To visualize any peaking at the weld, the inside and outside pipe diameters for a perfectly round cylinder are drawn in the Figures A1 through A7. API 5LX (1980) does not include requirements for the allowable angle between plate edges.

To estimate the original geometry for Mount M5 and Mount M6 prior to rupture, the CW fracture surface for each mount was rotated until the fatigue regions (Region 1) of the mating faces were parallel. The angles measured on the failed joint ranged between 161 degrees at the rupture origin (Mount M5) and 165 degrees at MPI Indication 2 (Mount M2) with the other mounts having values in between. The angle at the reference locations on the adjacent joints was higher with 167 degrees on the D/S joint (Mount M3), and 169 degrees on the U/S joint (Mount M4).

ANSI/NACE MR0175/ISO 15156-2:2015, Petroleum, petrochemical and natural gas industries —Materials for use in H₂S-containing environments in oil and gas production — Part 2: Cracking-resistant carbon and low-alloy steels, and the use of cast irons.

3.5 Mechanical Testing

The results of tensile testing of duplicate, transverse base metal and seam weld specimens removed from the pipe joint that ruptured are shown in Table 7. The average yield strength (YS) and ultimate tensile strength (UTS) of the base metal were 70.3 ksi and 87.8 ksi, respectively. The average YS and UTS of the base metal samples meet the minimum YS and UTS requirements for API 5LX Grade X60 line pipe steel of 60.0 ksi and 75.0 ksi, respectively. The average UTS of duplicate transverse samples removed from the longitudinal seam weld was 85.7 ksi, which exceeds the minimum UTS requirement for API 5LX Grade X60 line pipe steel of 75.0 ksi. YS values across welds are not specified in API 5LX.

The results of tensile testing of transverse base metal specimens removed from the U/S and D/S joints are shown in Table 8. The specimens meet the minimum YS and UTS requirements for API 5LX Grade X60 line pipe steel of 60 ksi and 75.0 ksi, respectively.

Table 9 and Table 10 summarize the results of the Charpy testing for the transverse base metal and seam weld samples removed from the failure joint while Figure 54 through Figure 57 show the Charpy percent shear and impact energy curves. An analysis of the data for the base metal specimens indicates that the 85% fracture appearance transition temperature (FATT) is 10.8°F and the upper shelf Charpy energy is 31.7-ft·lbs, full size. These results are typical for this vintage and grade of line pipe steel.

The CVN test results can be adjusted to determine the 85% FATT that would be expected for full-scale pipe by applying temperature shifts to the data. This method (full-scale) adjusts the 85% FATT obtained from the Charpy tests to a predicted FATT from the Battelle Drop-Weight Tear Test (BDWTT). The predicted 85% FATT from the BDWTT test most closely represents the expected FATT for full-scale pipe wall material. The full-scale brittle to ductile transition temperatures for the samples, based on a nominal pipe wall thickness of 0.260 inches, are shown in Table 11. The base metal is expected to exhibit ductile fracture behavior above 0.2°F. 11

Similarly, the data for the seam weld (HAZ) specimens indicates that the 85% FATT is -62.1°F and the upper shelf Charpy energy is 34.0 ft·lbs, full size. The seam weld (HAZ) is expected to exhibit ductile fracture behavior above -63.6°F, refer to Table 11.

⁹ API 5LX, 23rd Edition, 1980.

¹⁰ W. A. Maxey, J. F. Kiefner, R. J. Eiber, *Brittle Fracture Arrest in Gas Pipelines*," NG-18 Report No. 135, A.G.A. Catalog No. L51436, April 1983, Battelle Columbus Laboratories.

¹¹ Rosenfeld, M.J., "A Simple Procedure for Synthesizing Charpy Impact Energy Transition Curves from Limited Test Data," International Pipeline Conference, Volume 1, ASME, 1996, Equation 1.

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3.6 Chemical Analysis

The results of the chemical analysis performed on samples removed from the pipe joint that ruptured and the U/S and D/S joints are shown in Table 12. All three joints meet the composition requirements for API 5LX Grade X60 for this vintage.

3.7 Failure Pressure Analysis

CorLAS™ was used to estimate the failure pressure for the following cases:

- Case 1: Measured mechanical base-metal properties, measured pipe dimensions, and the as-measured flaw profile of Region 1 (Fatigue).
- Case 2: Measured mechanical base-metal properties, measured pipe dimensions, and the as-measured flaw profile of Region 1 (Fatigue) + Region 2 (Possible Environmental Cracking).
- Case 3: Measured mechanical HAZ properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue).
- Case 4: Measured mechanical HAZ properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue) + Region 2 (Possible Environmental Cracking).

The results of the analyses are shown in Table 13. The calculated failure pressure, incorporating the base-metal properties, for Case 1 and Case 2 are 1413 psig and 658 psig, respectively. Similar results were obtained using the mechanical properties of the HAZ, which resulted in calculated failure pressures of 1394 psig and 664 psig for Case 3 and Case 4, respectively. Additional details of the analyses, and a description of CorLASTM, are summarized in Appendix B.

Using the provided discharge pressure at Tracy pump station (694 psig) and suction pressure at Marsh Creek pump station (364.6 psig) at the time of failure, the pressure at the failure location was calculated from provided elevation data. The elevation of the failure location was estimated to be 365 feet, resulting in a calculated pressure of 665 psig. ¹² By incorporating the flaw profile of Region 2 (Case 2 and Case 4), the estimated failure pressure is in good agreement with the calculated pressure at the location and time of failure.

¹² Stationing data was not available, so the failure location was estimated to be 0.5 miles downstream of the Tracy pump station.

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4.0 CONCLUSIONS

The results of the metallurgical analysis indicate that the pipe joint ruptured at a fatigue crack that initiated at the toe of the DSAW seam weld on the inside surface of the pipe. Likely contributing factors include the peaked geometry of the failed pipe joint at the seam weld that introduced a bending stress, corrosion micro-pits on the ID surface that provided initiation sites, aggressive pressure cycling of the pipeline, and possibly an environmental effect on crack growth.

The fatigue crack initiation and propagation most likely occurred while in service. However, transit fatigue during transportation of the pipe cannot be ruled out as a contributing factor. Shell reported to have records of rail transportation per API 5L1, ¹³ for the first portion of the journey, from Houston Texas to the northeast of the U.S. For the second portion of the journey, from the northeast to Coalinga California, verbal information indicates that API 5L1 would have been specified per industry norms, but written records have not been located.

Summary of observations:

- The pipe joint that ruptured contained several types of mill anomalies at the long seam weld, including peaking, weld overlap¹⁴, and weld undercut¹⁵.
- The fatigue crack at the rupture origin was 6.96 inches long and initiated from small (50-100 micron) pits along the internal toe of the DSAW. There was no evidence of a pre-existing weld-type defect at this location. The long-seam weld was located at the 3:26 o'clock orientation.
- The fracture surfaces consisted of three regions:
 - ◆ Region 1 a crack region at the internal surface with a maximum depth of 0.097 inches (37.3% of 0.260 inches nominal wall thickness) caused by fatigue;
 - Region 2 a crack region with a stair-stepped appearance, beginning at the end of Region 1, resulting from higher stress intensity factor at the crack tip as the crack propagated deeper into the material and possibly an environmental component. The maximum depth of this region is 0.210 inches (80.8% of 0.260 inches nominal wall thickness);
 - Region 3 the remaining ligament that overloaded during the rupture event.
- MPI testing revealed other crack-like flaws on the pipe joint that failed, at approximately 2.7 feet D/S and 7.7 feet D/S of the rupture origin along the internal

¹³ API RP 5L1, Recommended Practice for Railroad Transportation of Line Pipe.

¹⁴ Weld overlap is an imperfection at the toe or root of a weld caused by metal flowing onto the surface of the parent metal without fusing to it. It may occur in both fillet and butt welds.

¹⁵ Weld undercut is an irregular groove at the toe of a weld run in the parent metal. A common cause of undercut is a wide spreading arc (high arc voltage) with insufficient fill (low current or high travel speed).

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surface of the DSAW. The largest feature (MPI Indication 1a) was 4.25 inches in length and 0.125 inches depth (48.1% of 0.260 inches nominal wall thickness) at the deepest location.

- Qualitative spot testing indicated the presence of sulfides on the fracture surface at the failure origin, which is not uncommon in crude oil pipelines.
- Cross-sections showed that cracks at weld toes at locations away from the rupture were filled with sulfur-containing products, which is not uncommon in crude oil pipelines.
- There was no evidence of external corrosion on the pipe section.
- No MPI indications were identified on portions of the longitudinal seam weld of the U/S or D/S joints that were examined; 1.58 feet of the U/S joint and 1.79 feet of the D/S joint.
- The tensile properties of the failed joint and the joints U/S and D/S of the failed joint meet the tensile requirements for API 5LX Grade X60 line pipe steel for the estimated vintage of the pipe (1980).
- The Charpy V-notch (CVN) properties of the base metal of the failed joint are typical for the vintage and grade of line pipe steel. The seam weld HAZ had better fracture toughness properties than the base metal, with a slightly higher upper shelf impact energy and lower 85% FATT temperature.
- The composition of the base metal of the failed joint and the joints U/S and D/S of the failed joint meets requirements for API 5LX Grade X60 line pipe steel for the estimated vintage of the pipe (1980).
- The microstructures of the pipe joints are typical for the vintage and grade of line pipe steel.
- The estimated failure pressure using mechanical properties of the heat affected zone and the flaw profile that ruptured for Region 1 + Region 2 is 664 psig, which is close to the calculated pressure at the failure location and time of failure (665 psig).

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Table 1. Results of diameter measurements performed on the U/S and D/S joints, adjacent to the failed pipe joint.

	Diameter (inches)		
Location	12 to 6 o'clock ¹	3 to 9 o'clock ¹	
U/S end of U/S Joint	24.2	23.9	
D/S end of D/S Joint	24.1	24.1	

1 - Measurements exclude coating thickness.

Table 2. Results of wall thickness measurements performed on the U/S, D/S, and failed pipe joints in areas with negligible corrosion and no coating.

	Wall Thickness (inches)					
O'clock Orientations	U/S End of U/S Joint ⁴	U/S End of Ruptured Joint	Near Failure Location in Ruptured Joint	D/S End of Ruptured Joint	D/S End of D/S Joint	
12:00	0.279	0.277	0.278	0.278	0.295	
3:00	0.296	0.274	0.251 1	0.273 ²	0.295	
6:00	0.289	0.272	0.278	0.278	0.267	
9:00	0.289	0.273	0.276	0.276	0.272	
Average	0.288	0.274	N/A ³	0.276	0.282	

- 1 Measurements taken near Mount M5 location, CCW side of the seam weld.
- 2 Measurement average near Mount M2 and Mount M7, CCW side of the seam weld.
- 3 Average not applicable, because of yielding near rupture opening.
- 4 This is 1.58 feet U/S of the D/S end of the U/S joint.

Table 3. Summary of locations of metallurgical mounts and other features on the received pipe section.

Location	Cross-Section	Distance from U/S GW (feet)
End of U/S Pipe Section	_	-1.58
U/S Girth Weld	_	0.00
U/S Joint	Mount M4	-1.54
U/S End of Rupture Opening	-	14.17
U/S End of Pre-Existing ID Flaw	_	15.88
Section through Rupture Origin	Mount M5	16.13
Section through Rupture	Mount M6	16.33
D/S End of Pre-Existing ID Flaw	_	16.46
D/S End of Rupture Opening	, , , , , , , , , , , , , , , , , , , 	17.94
U/S End of MPI Indication 1a (CW)	_	18.62
U/S End of MPI Indication 1b (CCW)	_	18.70
Section through MPI 1a and 1b	Mount M1	18.81
D/S End of MPI Indication 1a (CW)	_	19.05
D/S End of MPI Indication 1b (CCW)	_	19.12
Failed Joint, Away from Rupture	Mount M7	21.16
MPI Indication 2	Mount M2	23.83
D/S Girth Weld		26.44
D/S Joint	Mount M3	28.19
End of D/S Pipe Section	_	28.23

Table 4. Summary of the locations and dimensions of indications identified on the internal surface of failed joint by magnetic particle inspection.

MPI Indication	Distance ² from U/S GW (feet)	Axial Length (inches)	O'clock Orientation	Depth ¹ (inches)
Indication 1a Crack-like indication on ID surface. At HAZ on CW side of seam weld	18.62	5.6	3:26	0.119 Crack at CW side
Indication 1b Crack-like indication with weld overlap on ID surface. At HAZ on CCW side of seam weld	18.70	0.35	3:26	0.000 No crack under overlap
Indication 2 Notch (weld undercut) on ID surface. At HAZ on CW side of seam	23.83	0.02	3:26	0.060 Notch at HAZ 0.011 Crack from notch

^{1 –} Measurements made on metallographic cross-sections.

Table 5. Results of EDS analyses (in wt.%) performed on corrosion products remaining within corrosion pits at weld toe on the internal pipe surface of Mount M2. Refer to Figure 47 for analysis locations.

Spectrum		EDS #1	EDS #2	EDS #3	EDS #4
Carbon	(C)	_	_	_	-
Oxygen	(O)	8	11.4	7 .	5.4
Sodium	(Na)	-	-	_	_
Aluminum	(AI)	-	0.1	-	1.7
Silicon	(Si)	0.1	0.4	0.1	0.5
Phosphorous	(P)	_		_	0.1
Sulfur	(S)	32.3	31.6	27.0	0.1
Calcium	(Ca)	0.2	0.3	0.2	0.1
Chromium	(Cr)	-	-	_	0.1
Manganese	(Mn)	_	0.6	0.4	0.9
Copper	(Cu	-	-	=	0.2
Iron	(Fe)	59.4	55.7	65.3	91

^{2 -} Distance indicates U/S end of the indication.

Table 6. Results of measurements performed on Mounts M1-M7 to determine the angle between the plate edges on the CCW and CW sides of the seam weld. Refer to Appendix A for additional details.

Mount №	Location	Angle Between CW and CCW Sides (Degrees)
Mount M1	MPI Indications 1a / 1b	162
Mount M2	MPI Indication 2	165
Mount M3	D/S Joint	167
Mount M4	U/S Joint	169
Mount M5	Section Through Rupture Origin	161
Mount M6	Section Through Rupture	163
Mount M7	Failed Joint, Away from Rupture	165

Results of tensile tests performed on transverse base metal and weld (HAZ) Table 7. specimens from the joint that ruptured compared with requirements for API 5LX Grade X60 line pipe steel.²

	Base Metal	Seam Weld	API 5LX Grade X60 (Minimum Values) ²
Yield Strength, ksi ¹	70.3	_	60.0
Tensile Strength, ksi ¹	87.8	85.7	75.0
Elongation in 2 inches, % 1	26.0	_	20.6
Reduction of Area, % 1	33.7	32.7	-

Results of tensile tests performed on transverse base metal specimens from the Table 8. U/S and D/S joints compared with requirements for API 5LX Grade X60 line pipe steel.2

	U/S Base Metal	D/S Base Metal	API 5LX Grade X60 (Minimum Values) ²
Yield Strength, ksi ¹	77.7	71.2	60.0
Tensile Strength, ksi ¹	95.6	86.8	75.0
Elongation in 2 inches, % 1	22.7	27.2	20.6
Reduction of Area, % ¹	29.1	33.3	_

^{1 –} Average of duplicate tests. 2 – API 5LX, 23rd Edition, 1980.

^{1 –} Average of duplicate tests. 2 – API 5LX, 23rd Edition, 1980.

Table 9. Results of Charpy V-notch impact tests performed on transverse base metal specimens removed from the joint that ruptured.

Sample ID	Temperature, °F	Sub-Size Impact Energy, ft-Ibs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, inches
A-10	-60	6	11	5	0.006
A-6	-45	5	9	10	0.011
A-9	-30	7	12	35	0.012
A-5	-20	7	12	35	0.017
A-8	-10	7	12	35	0.013
A-7	0	11	19	80	0.020
A-4	5	15	26	90	0.028
A-3	30	16	28	95	0.031
A-2	55	20	35	100	0.034
A-1	80	18	32	100	0.034

Table 10. Results of Charpy V-notch impact tests performed on transverse seam weld (HAZ) specimens removed from the joint that ruptured.

Sample ID	Temperature, °F	Sub-Size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, inches
B-10	-100	6	12	0	0.012
B-9	-80	6	11	5	0.011
B-8	-60	12	24	95	0.029
B-6	-45	14	28	95	0.026
B-7	-30	15	30	100	0.028
B-5	-20	15	30	100	0.027
B-4	5	15	30	100	0.027
B-3	30	17	33	100	0.029
B-2	55	16	32	100	0.035
B-1	80	18	36	100	0.037

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Table 11. Results of analyses of the Charpy V-notch impact energy and percent shear plots for base metal and seam weld (HAZ) specimens removed from the joint that ruptured.

	Base Metal	Seam Weld (HAZ)
Upper Shelf Impact Energy (Full Size), Ft-lbs	31.7	34.0
85% FATT, °F	10.8	-62.1
85% FATT, °F (Full Scale Pipe) ¹	0.2	-63.6

1 – Full Scale Pipe FATT = 85% FATT + (($66*(t_w^{0.55}/t_c^{0.7})$ -100) where t_w = pipe wall thickness and t_c = width of the CVN specimen.

Table 12. Results of chemical analyses performed on samples removed from the joint that ruptured and the U/S and D/S joints compared with composition requirements for API 5LX Grade X60 line pipe steel.¹

	Element	Composition, Joint That Ruptured (Wt. %)	Composition, U/S Joint (Wt. %)	Composition, D/S Joint (Wt. %)	API 5LX Grade X60 Spec (Wt. %) ¹
С	(Carbon)	0.158	0.174	0.160	0.29 (max)
Mn	(Manganese)	1.23	1.40	1.32	1.45 (max)
Р	(Phosphorus)	0.010	0.024	0.008	0.05 (max)
S	(Sulfur)	0.019	0.017	0.017	0.06 (max)
Si	(Silicon)	0.028	0.047	0.030	_
Cu	(Copper)	0.110	0.075	0.107	
Sn	(Tin)	0.005	0.004	0.005	_
Ni	(Nickel)	0.118	0.195	0.093	_
Cr	(Chromium)	0.135	0.146	0.097	· -
Мо	(Molybdenum)	0.045	0.050	0.049	_
Al	(Aluminum)	0.001	0.001	0.001	=
V	(Vanadium)	0.024	0.025	0.026	0.01 (min)*
Nb	(Niobium)	0.020	0.028	0.026	0.005 (min)*
Zr	(Zirconium)	0.002	0.002	0.002	-
Ti	(Titanium)	0.001	0.001	0.001	0.02 (min)*
В	(Boron)	0.0003	0.0003	0.0003	-
Ca	(Calcium)	0.0005	0.0006	0.0005	
Co	(Cobalt)	0.009	0.009	0.008	_
Fe	(Iron)	Balance	Balance	Balance	Balance
Carbon Equivalent, CE _{IIW} ²		0.42	0.47	0.43	_

^{1 –} Product Analysis per API 5LX, 23rd Edition, 1980, for welded, non-expanded or cold-expanded Grade X60 pipe.

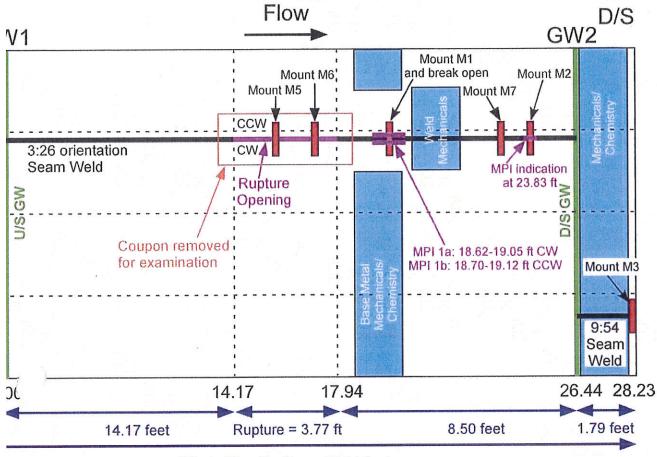
 $^{2 -} CE_{IIW} = C + (Mn/6) + (Cr+Mo+V)/5 + (Ni+Cu)/15$

^{* –} Either niobium, vanadium, or titanium, or a combination thereof, shall be used at the discretion of the manufacturer.

Table 13. Results of failure pressure analyses using $CorLAS^{TM}$. The pressure at the failure site was estimated to be 665 psig.

Case №	Flaw Profile	Measured Properties	Estimated Failure Pressure (psig)
1	Equivalent Flaw (Region 1)	Base Metal	1413 ¹
2	Equivalent Flaw (Region 1+Region 2)	Base Metal	658 ¹
3	Equivalent Flaw (Region 1)	HAZ	1394 1
4	Equivalent Flaw (Region 1+ Region 2)	HAZ	664 ¹

1- J Fracture Toughness failure criterion



Whole Pipe Section = 29.81 feet

Distance to U/S GW (feet)

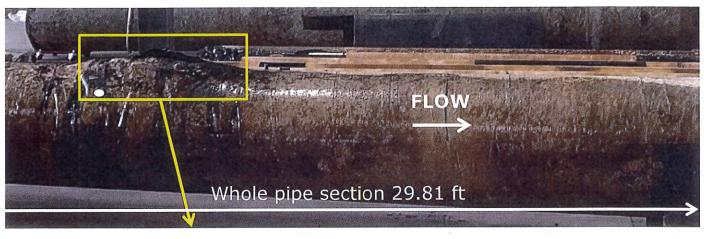
of Pipe Section showing the location of the rupture, MPI indications, and where samples were removed nical testing, chemistry, and metallography (Mounts M1, M2, M3, M4, M5, M6, M7).

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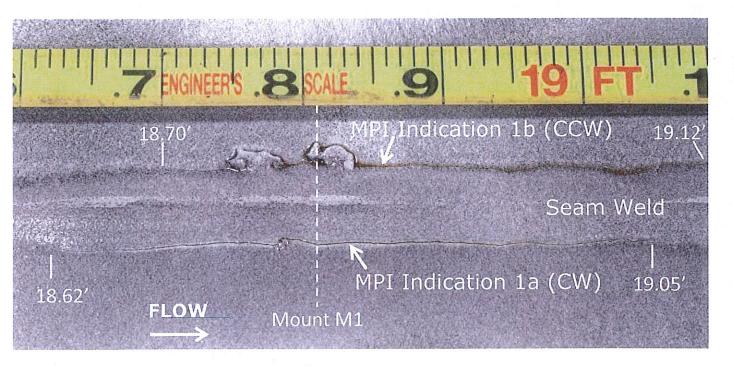
gure 2. Photograph of Pipe Section in the as-received condition at DNV GL.

8491)





ohs of Pipe Section showing the rupture location following removal of the protective plastic wrappings.

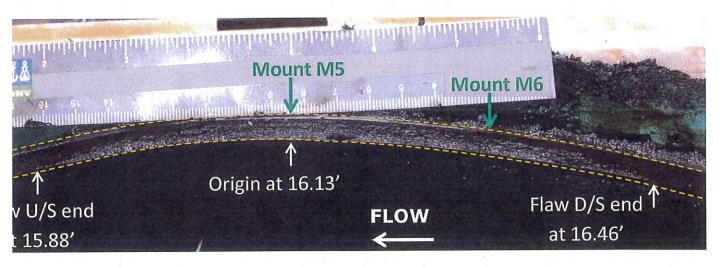


the internal pipe surface showing MPI Indication 1a and MPI Indication 1b along the clockwise iterclockwise (CCW) side of the seam weld, approximately 2.7 feet downstream of the rupture 18.62 – 19.12 ft D/S from U/S GW), and location where Mount M1 was removed.

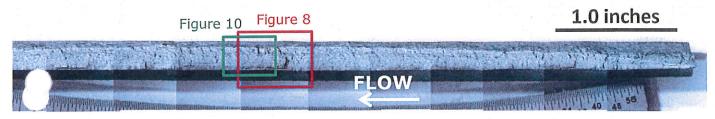
the internal pipe surface showing MPI Indication 2 along the clockwise (CW) side of the seam weld, atc., 7.7 feet downstream of the rupture location (23.83 ft D/S from U/S GW), and location where was removed.

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oh of the fracture surface (clockwise side) at the suspected rupture origin before cleaning. Light gray e-existing flaw that initiated from the pipe inside surface.



age of the fracture surface (clockwise side) at the suspected rupture origin after cleaning in a degreaser anol. Light gray area is the pre-existing flaw that initiated from the pipe inside surface.

Shell Pipeline Company

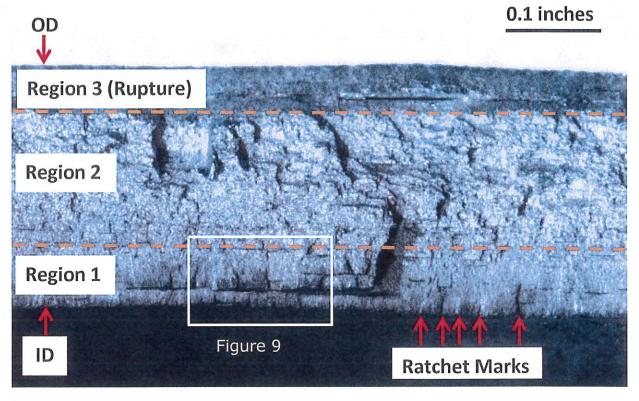


Figure 8. Photomicrograph showing a portion of the fracture surface from the rupture, clockwise (CW) side of the seam weld, after cleaning with a degreaser and methanol. Area indicated in Figure 7.

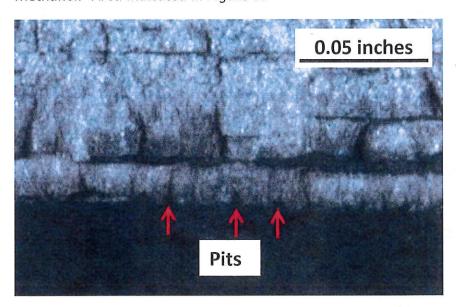


Figure 9. Photomicrograph showing close-up view of pits at ID pipe surface; area indicated in Figure 8.

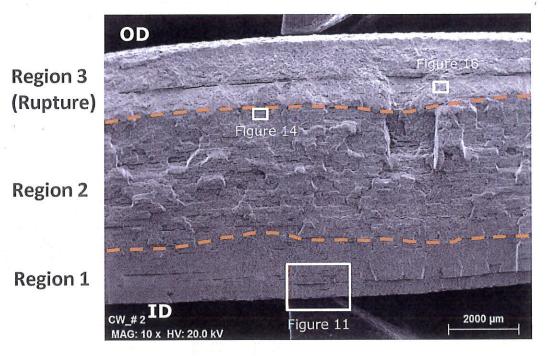


Figure 10. SEM photomicrograph showing three distinct morphologies on fracture surface from rupture, 10X; area indicated in Figure 7

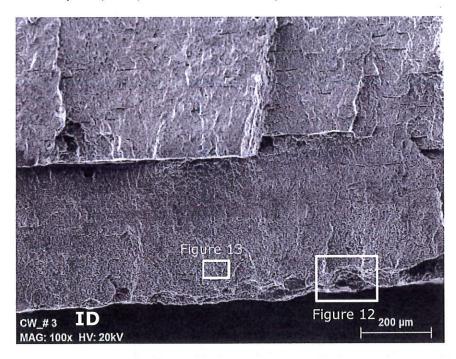


Figure 11. SEM photomicrograph showing Region 1 of fracture surface from rupture, 100X; area indicated in Figure 10.

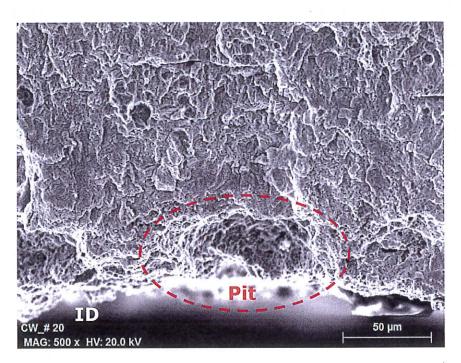


Figure 12. SEM photomicrograph showing pit at ID surface 500X; area indicated in Figure 11.

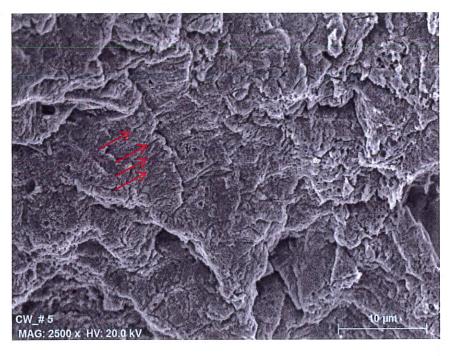


Figure 13. SEM photomicrograph showing fatigue striations in Region 1, 2500X; area indicated in Figure 11.

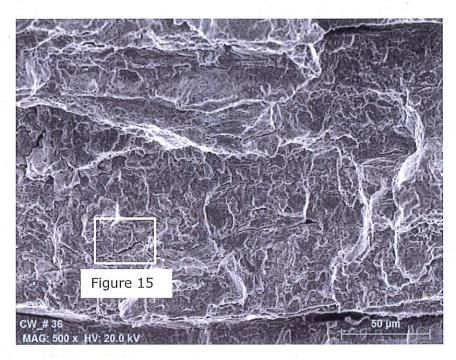


Figure 14. SEM photomicrograph showing secondary cracking within Region 2, 500X; area indicated in Figure 10.

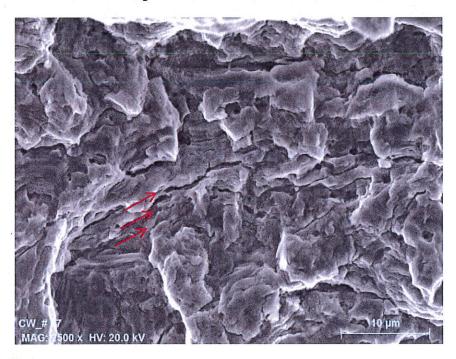


Figure 15. SEM photomicrograph showing small cracks on corrosion product-covered fracture surface in Region 2, 2500X; area indicated in Figure 14.

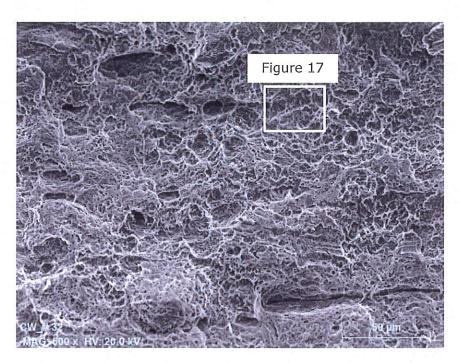


Figure 16. SEM photomicrograph showing ductile fracture morphology in Region 3, 500X; area indicated in Figure 10.

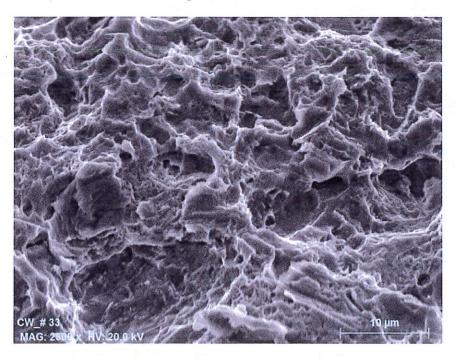
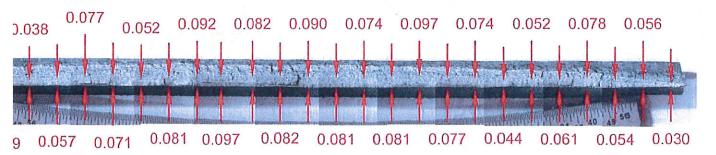


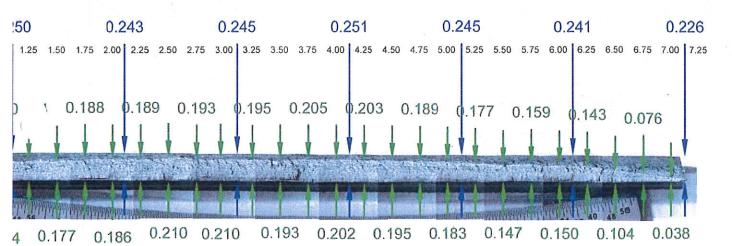
Figure 17. SEM photomicrograph showing ductile fracture morphology in Region 3, 2500X; area indicated in Figure 16.

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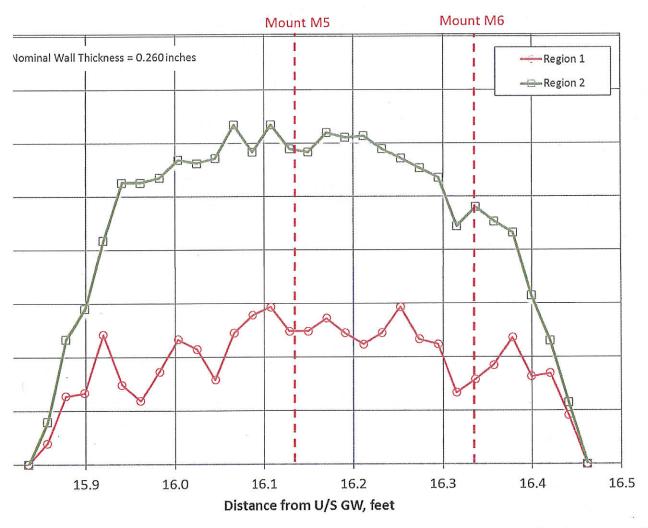
1.25 1.50 1.75 2.00 2.25 2.50 2.75 3.00 3.25 3.50 3.75 4.00 4.25 4.50 4.75 5.00 5.25 5.50 5.75 6.00 6.25 6.50 6.75 7.00 7.25



age of the fracture surface (clockwise side), showing depth measurements (red) of Region 1 of the preaw.



age of the fracture surface (clockwise side), showing depth measurements (green) of Region 1 and of the pre-existing flaw, together with wall thickness measurements (blue).



h versus distance from the U/S GW for Region 1 and Region 2 identified on the fracture surface. The of Mount M5 and Mount M6 are indicated by dashed lines.

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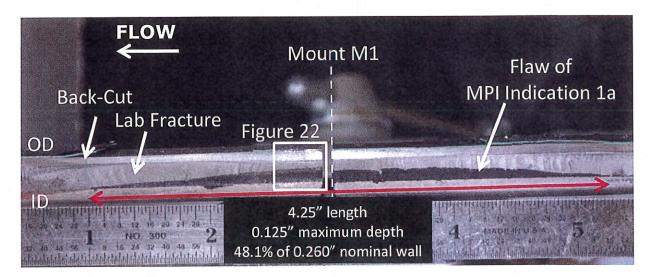


Figure 21. Photograph of the clockwise (CW) side of the fracture surface associated with MPI Indication 1a, and location of Mount M1.

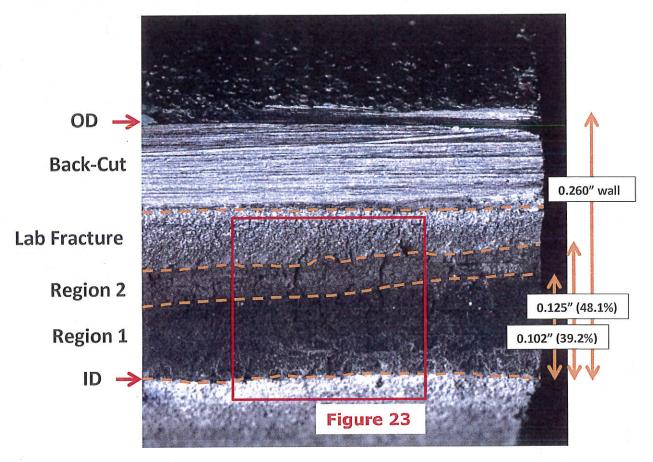


Figure 22. Stereo-photograph showing a portion of the fracture surface associated with broken open MPI Indication 1a, without cleaning. Area indicated in Figure 21.

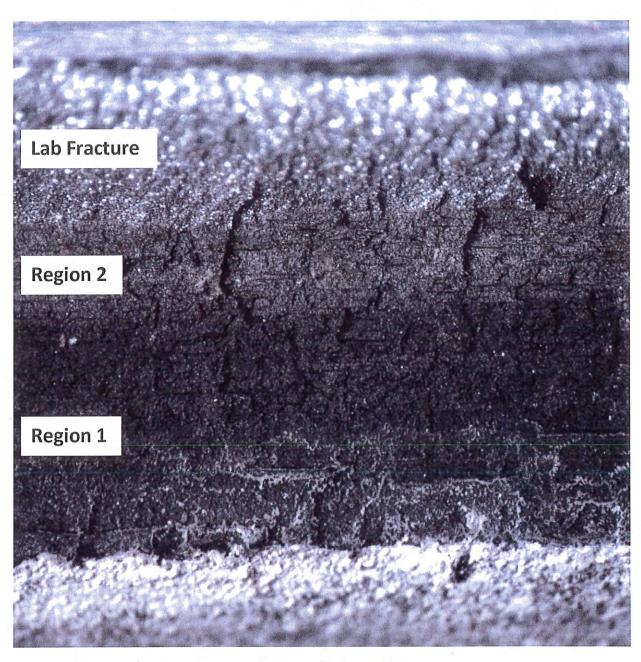


Figure 23. Stereo-photograph showing a close-up view of the fracture surface associated with broken open MPI Indication 1a, without cleaning. Area indicated in Figure 22.

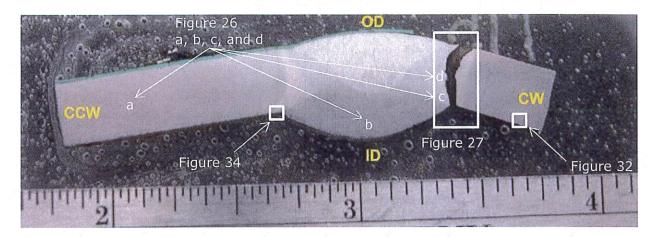


Figure 24. Photograph of the mounted cross-section (Mount M5) removed from the likely rupture origin; 16.13 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

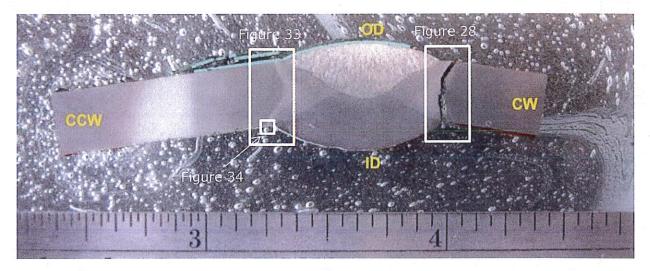


Figure 25. Photograph of the mounted cross-section (Mount M6) removed from the ruptured joint, just D/S from the likely rupture origin; 16.33 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

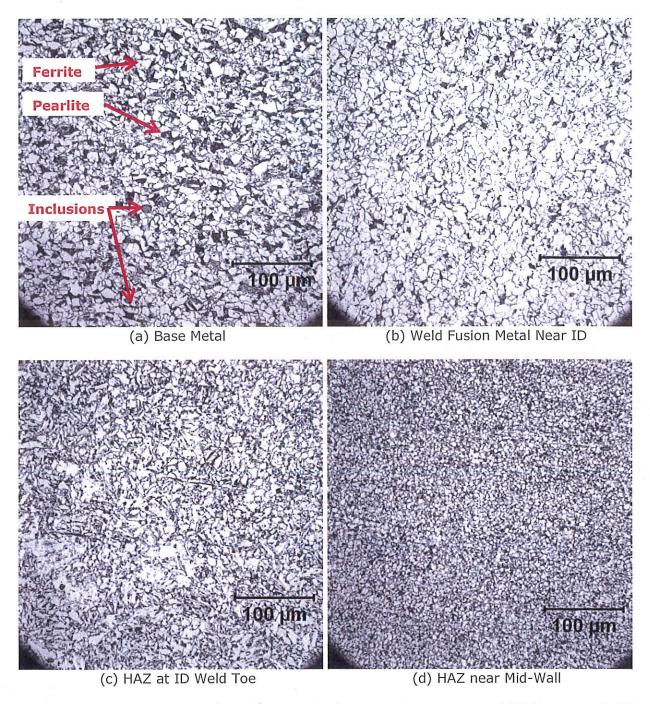


Figure 26. Photomicrographs of Mount M5, showing microstructure of (a) base metal, (b) weld fusion metal near ID, (c) HAZ metal near ID weld toe, and (d) HAZ metal near mid-wall. Locations indicated in Figure 25. 4% Nital Etch.

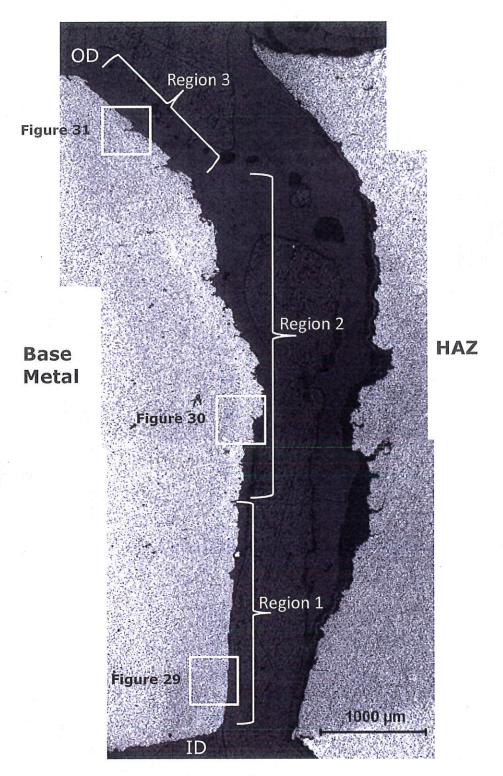


Figure 27. Photomicrograph of Mount M5, clockwise (CW) side of the weld, showing the fracture path in cross-section; area indicated in Figure 24. 4% Nital Etch.

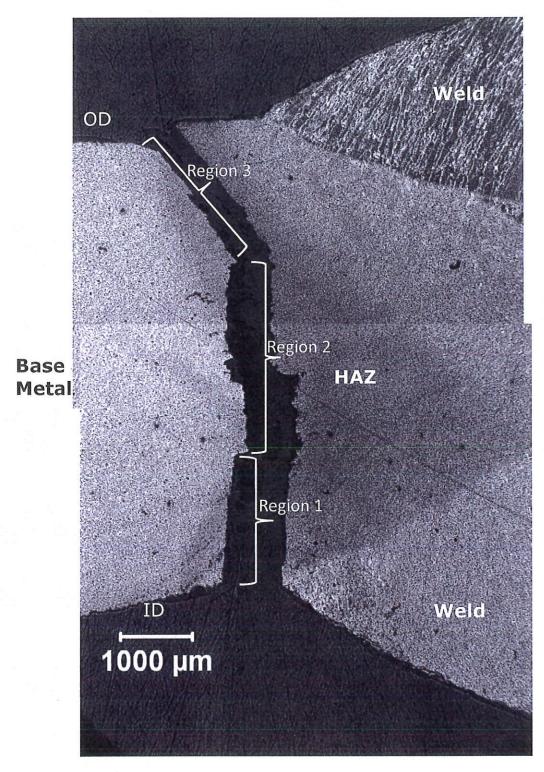


Figure 28. Photomicrograph of Mount M6, clockwise (CW) side of the weld, showing the fracture path in cross-section; area indicated in Figure 25. 4% Nital Etch.

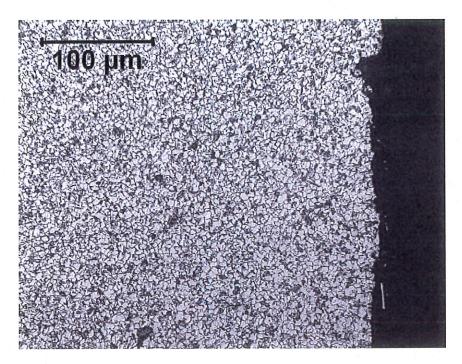


Figure 29. Photomicrograph of Mount M5 showing the microstructure and the fracture profile within Region 1 near the internal pipe surface; area indicated in Figure 27. 4% Nital Etch.

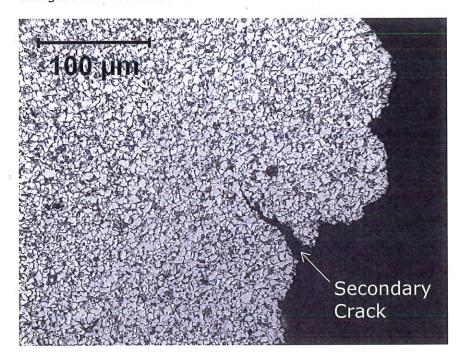


Figure 30. Photomicrograph of Mount M5 showing the microstructure and the fracture profile within Region 2; area indicated in Figure 27. 4% Nital Etch.

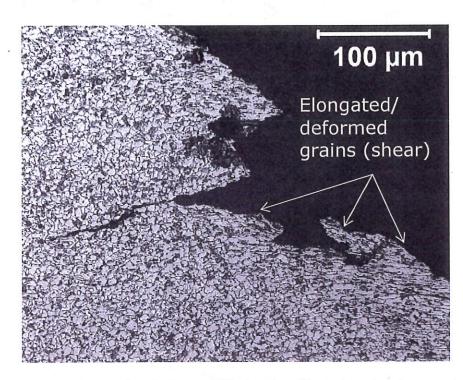


Figure 31. Photomicrograph of Mount M5 showing the microstructure and the fracture profile within Region 3 near the external pipe surface; area indicated Figure 27. 4% Nital Etch.

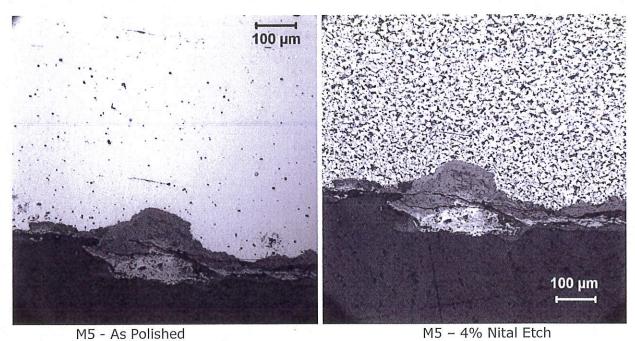


Figure 32. Photomicrographs of Mount M5 showing round and elongated inclusions in the base metal and corrosion product in a micro-pit on the ID surface of the pipe; area indicated in Figure 24.

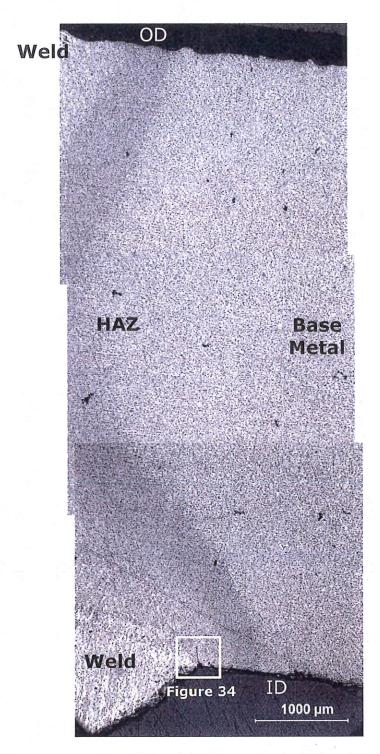


Figure 33. Photomicrograph of Mount M6, counterclockwise (CCW) side of the weld, showing a small crack at the weld toe; area indicated in Figure 25. 4% Nital Etch.

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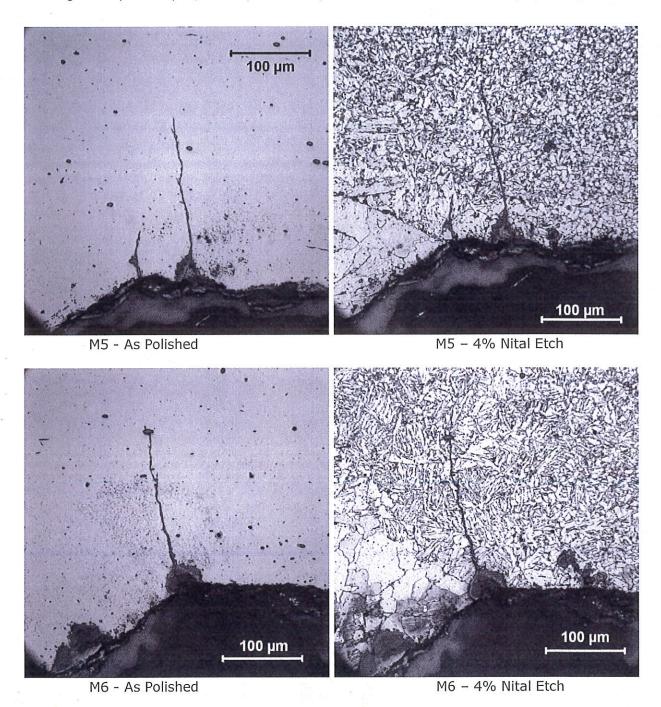


Figure 34. Photomicrographs of Mount M5 (top, refer to Figure 24) and Mount M6 (bottom, refer to Figure 25, showing cracks at weld toe with pits and corrosion products on ID pipe surface; counterclockwise (CCW) side of the seam weld.

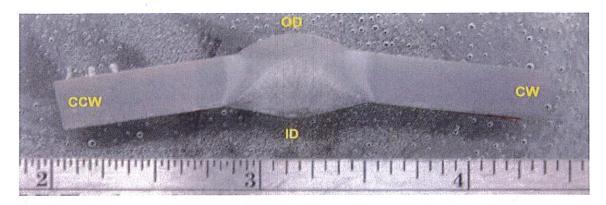


Figure 35. Photograph of the mounted cross-section (Mount M7) removed from the ruptured joint, away from the failure; 21.16 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1.4% Nital Etch.

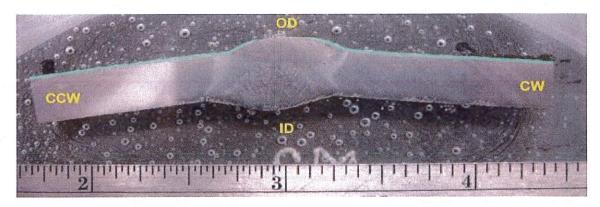


Figure 36. Photograph of the mounted cross-section (Mount M3) removed from D/S joint; 28.19 feet from the U/S GW (of the ruptured joint). Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

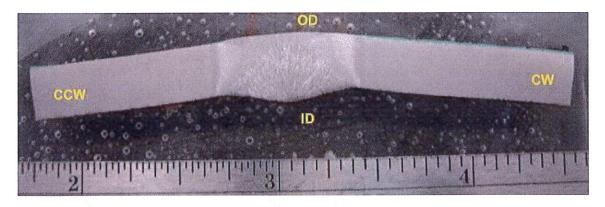


Figure 37. Photograph of the mounted cross-section (Mount M4) removed from U/S joint; -1.54 feet from the U/S GW (of the ruptured joint). Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

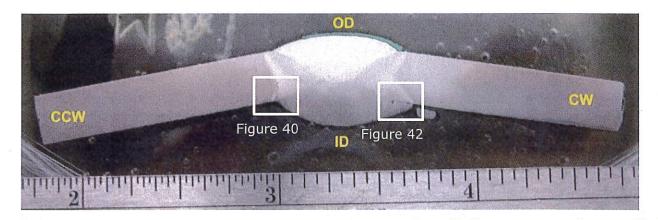


Figure 38. Photograph of the mounted cross-section (Mount M1) removed from MPI Indication 1a (CW) and MPI Indication 1b (CCW) of the ruptured joint, away from the rupture; 18.81 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

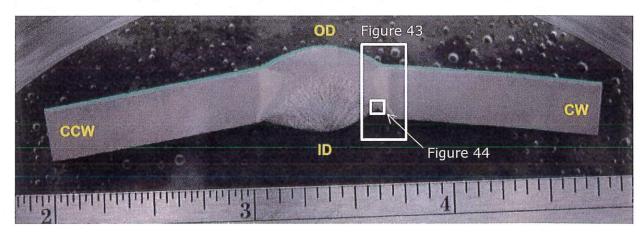


Figure 39. Photograph of the mounted cross-section (Mount M2) removed from MPI Indications 2 (CW) of the ruptured joint, away from the rupture; 23.83 feet from the U/S GW. Flow direction is into the page. Location indicated in Figure 1. 4% Nital Etch.

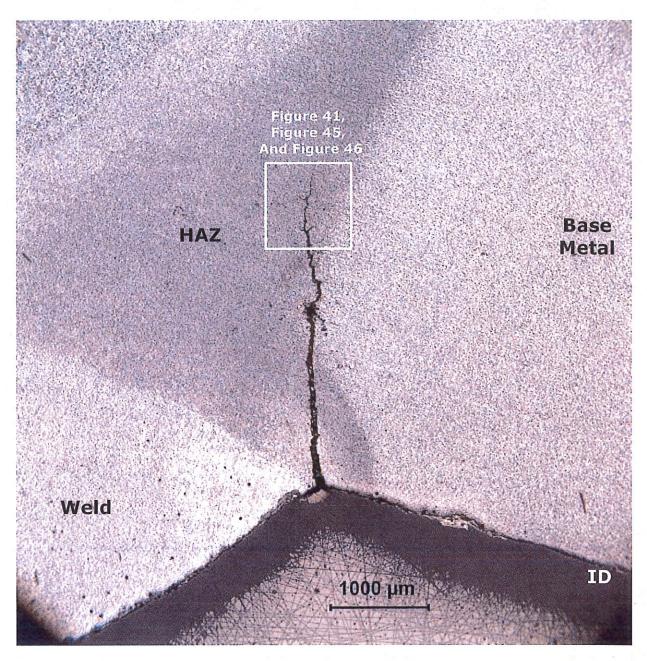


Figure 40. Photomicrograph of Mount M1 (MPI Indication 1a) showing crack at weld toe from ID surface on clockwise (CW) side of the seam weld; mirror image of area indicated in Figure 38. 4% Nital Etch.

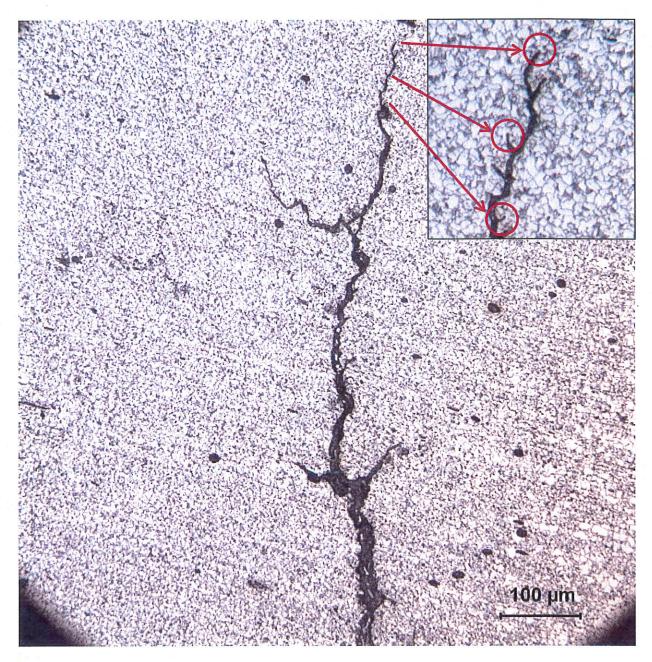


Figure 41. Photomicrograph of Mount M1 (MPI Indication 1a) showing crack tip on clockwise (CW) side of the seam weld; area indicated in Figure 40. 4% Nital Etch. Inset photo shows close-up of transgranular morphology at crack tip.

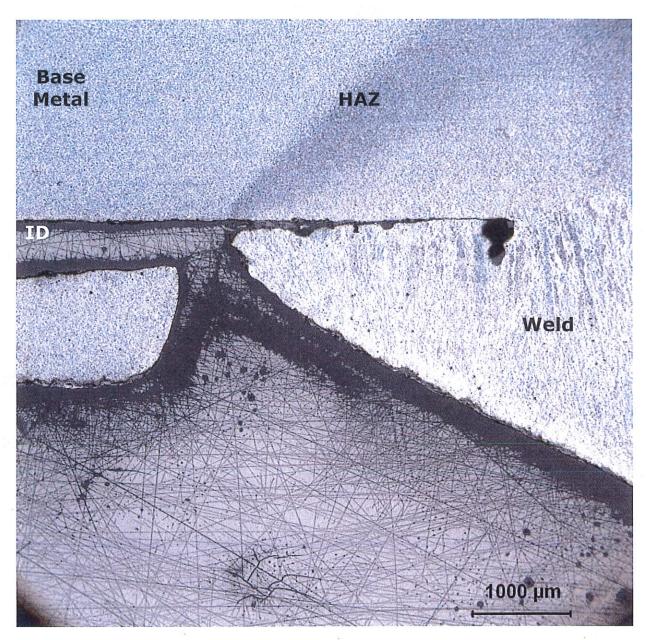


Figure 42. Photomicrograph of Mount M1 (MPI Indication 1b) showing overlap of weld bead on ID surface, counterclockwise (CCW) side of the seam weld; mirror image of area indicated in Figure 38. 4% Nital Etch.



Figure 43. Photomicrograph of Mount M2 (MPI Indication 2), clockwise (CW) side of the weld, showing a notch from undercut at the weld toe; mirror image of area indicated in Figure 39. 4% Nital Etch.

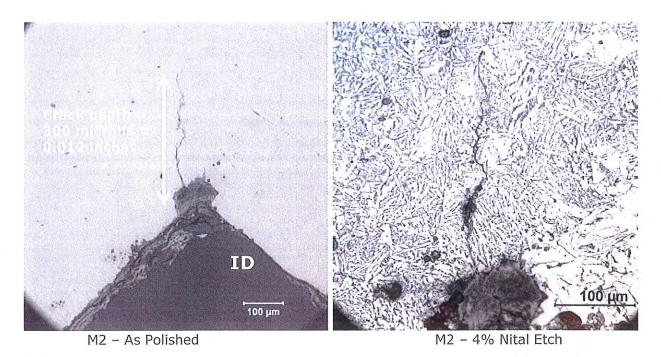


Figure 44. Photomicrographs of Mount M2 (MPI Indication 2) showing crack at weld toe from ID surface on clockwise (CW) side of the seam weld; mirror images of area indicated in Figure 39.

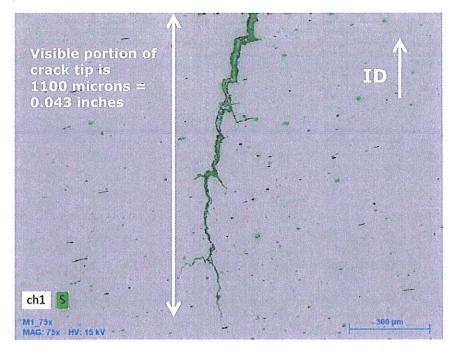


Figure 45. EDS map of Mount M1 (MPI Indication 1a) at crack shown in Figure 40, showing presence of sulfur at tip of the crack that started at weld toe from ID surface on clockwise (CW) side of the seam weld.

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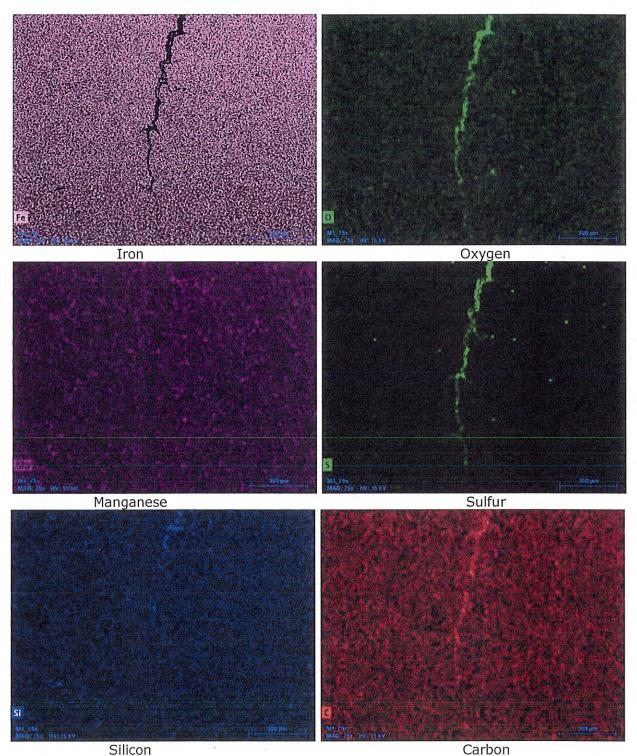


Figure 46. EDS map of Mount M1 (MPI Indication 1a) at crack shown in Figure 40, showing distribution of Fe, O, Mn, S, Si, and C at tip of the crack that started at weld toe from ID surface on clockwise (CW) side of the seam weld.

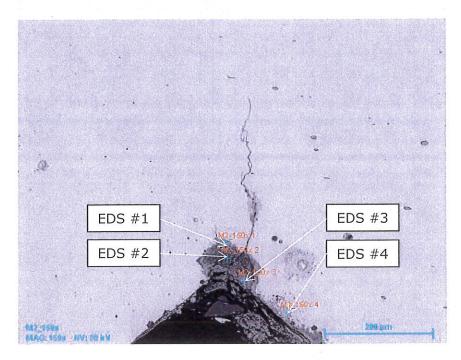


Figure 47. EDS measurement locations on Mount M2 (results shown in Table 5; also refer back to Figure 44), at weld toe crack with pit and corrosion product, from ID surface on counterclockwise (CCW) side of the seam weld.

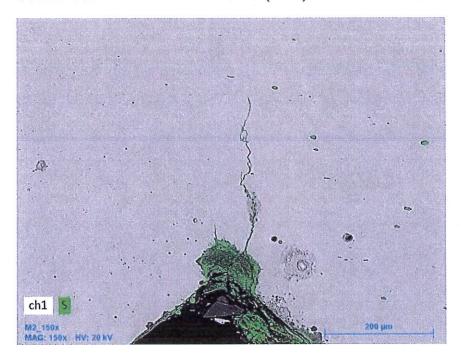


Figure 48. EDS map of Mount M2 (MPI Indication 2) at crack shown in Figure 47, showing distribution of sulfur.

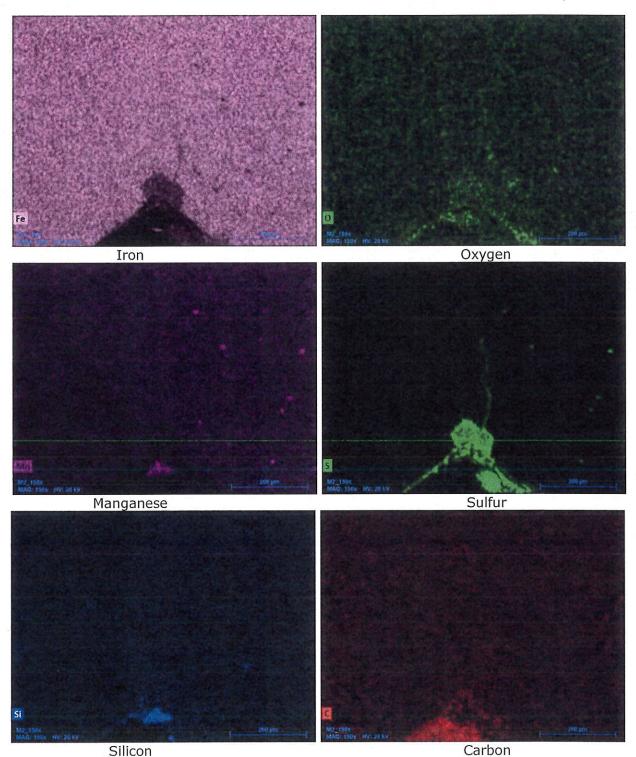
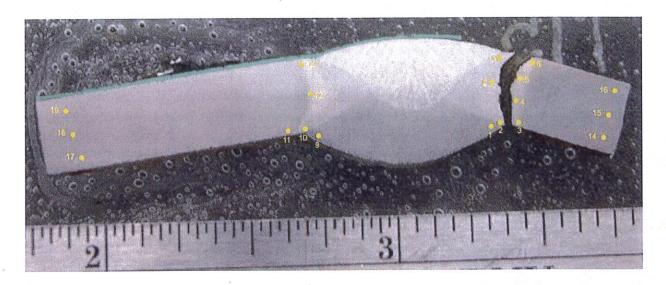


Figure 49. EDS map of Mount M2 (MPI Indication 2) at crack shown in Figure 47, showing distribution of Fe, O, Mn, S, Si, and C.

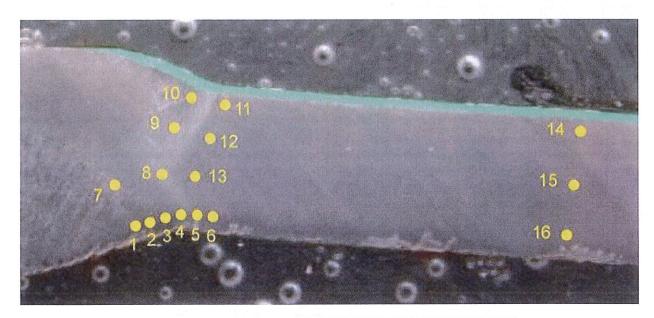
Shell Pipeline Company Metallurgical Analysis of May 20, 2016 Rupture on Tracy to Windmill Portion of San Pablo Bay Pipeline System



	Hardness (HV)			
Measurement Location	Mount M5 16.13 ft from U/S GW	Mount M6 16.33 ft from U/S GW		
1	190.3	192.5		
2	218.1	187.6		
3	204.1	201.7		
4	206.5	218.8		
5	210.9	209.1		
6	215.5	228.5		
7	204.1	206.0		
8	216.1	183.4		
9	163.1	176.4		
10	182.9	210.3		
11	201.7	214.8		
12	182.9	190.9		
13	207.8	190.9		
14	212.2	211.6		
15	197.0	208.4		
16	191.4	224.3		
17	227.8	214.8		
18	206.5	195.3		
19	180.4	180.9		

Figure 50. Results of hardness measurements at various locations on Mount M5 (Figure 24) and Mount M6 (Figure 25). Mount M5 shown above; measurements performed at similar locations on Mount M6.

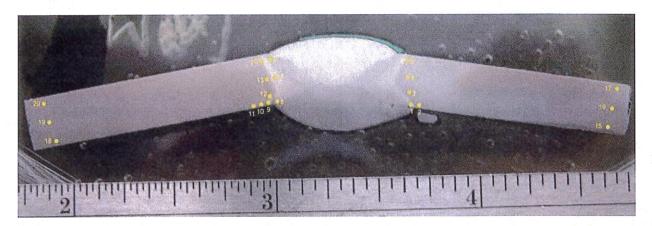
Shell Pipeline Company Metallurgical Analysis of May 20, 2016 Rupture on Tracy to Windmill Portion of San Pablo Bay Pipeline System



	Hardness (HV)			
Measurement Location	Mount M3 D/S joint	Mount M4 U/S joint	Mount M7 Failed joint	
1	183.4	213.4	193.1	
2	213.5	235.1	196.5	
3	195.3	226.4	218.1	
4	207.8	226.4	220.1	
5	205.3	227.8	225.0	
6	201.7	214.2	214.2	
7	205.3	216.8	214.2	
8	172.1	214.2	214.2	
9	201.1	205.3	200.5	
10	214.8	192.0	191.9	
11	201.1	227.8	204.1	
12	190.3	218.1	210.3	
13	180.4	199.9	210.3	
14	181.4	220.1	201.1	
15	183.4	205.3	193.1	
16	168.9	212.9	193.1	

Results of hardness measurements taken at representative locations on Mount M3 (Figure 36), Mount M4 (Figure 37), and Mount M7 (Figure 35). Mount M3 shown above; measurements performed at similar locations on Mount M4 and Mount M7.

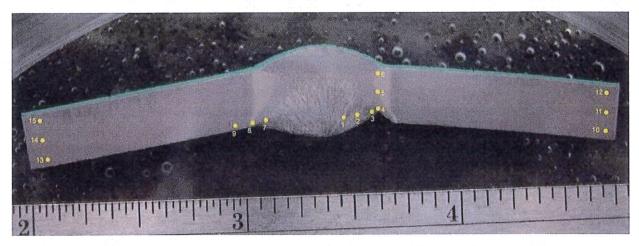
Shell Pipeline Company Metallurgical Analysis of May 20, 2016 Rupture on Tracy to Windmill Portion of San Pablo Bay Pipeline System



A CONTRACTOR OF THE PROPERTY O	
Measurement Location	Hardness (HV) Mount M1 MPI Indications 1a/1b
1	188.7
2	211.6
3	208.4
4	200.5
5	211.6
6	184.5
7	194.2
8	201.7
9	174.0
10	163.1
11	166.5
12	197.0
13	197.7
14	214.8
15	203.2
16	187.6
- 17	214.2
18	227.1
19	197.0
20	183.4

Figure 52. Results of hardness measurements at various locations on Mount M1.

Shell Pipeline Company Metallurgical Analysis of May 20, 2016 Rupture on Tracy to Windmill Portion of San Pablo Bay Pipeline System



Measurement	Hardness (HV		
Location	Mount M2		
1	179.9		
2	192.0		
3	210.3		
4	207.2		
5	197.6		
6	196.5		
7	199.3		
8	196.5		
9	204.1		
10	211.6		
11	180.9		
12	196.7		
13	194.2		
14	190.1		
15	191.4		

Figure 53. Results of hardness measurements at various locations on Mount M2.



Figure 54. Percent shear from Charpy V-notch tests as a function of temperature for transverse base metal specimens removed from the pipe joint that ruptured.

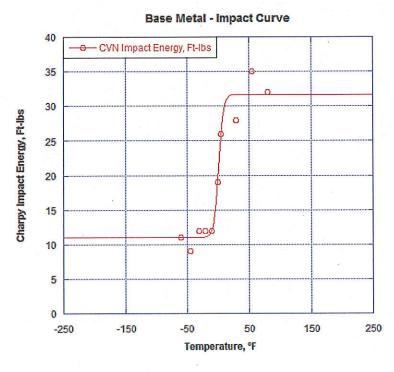


Figure 55. Charpy V-notch impact energy as a function of temperature for transverse base metal specimens removed from the pipe joint that ruptured.

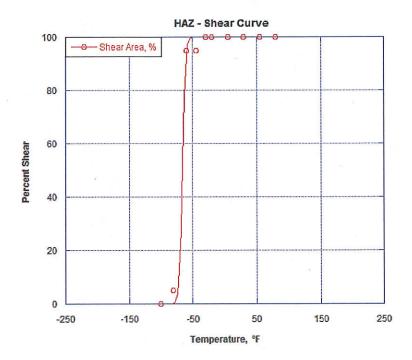


Figure 56. Percent shear from Charpy V-notch tests as a function of temperature for transverse seam weld (HAZ) specimens removed from the pipe joint that ruptured.

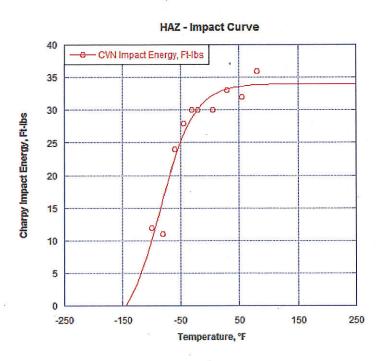


Figure 57. Charpy V-notch impact energy as a function of temperature for transverse seam weld (HAZ) specimens removed from the pipe joint that ruptured.

APPENDIX A

DSAW Measurements

Rupture Location

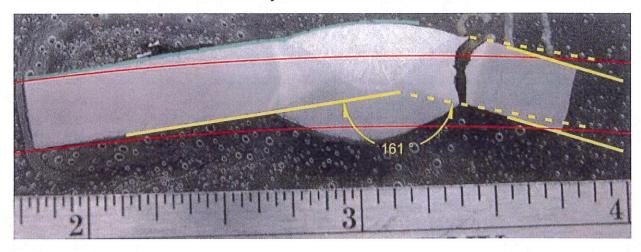


Figure A1. Photograph of the mounted cross-section (Mount M5) removed from Rupture Origin, 16.13 feet from the U/S GW.

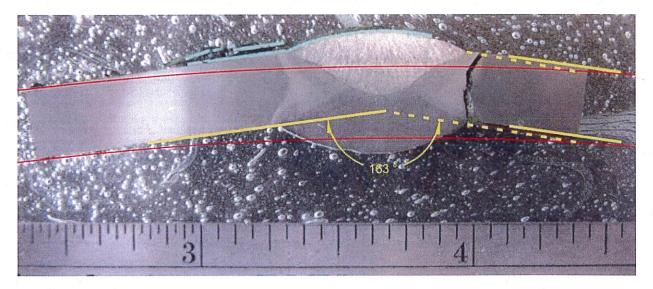


Figure A2. Photograph of the mounted cross-section (Mount M6) removed from Rupture Origin, 16.33 feet from the U/S GW.

Reference Locations

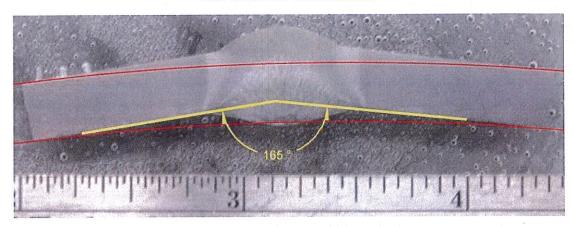


Figure A3. Photograph of the mounted cross-section (Mount M7) removed from Failed Joint, Away from the Rupture, 21.16 feet from the U/S GW.

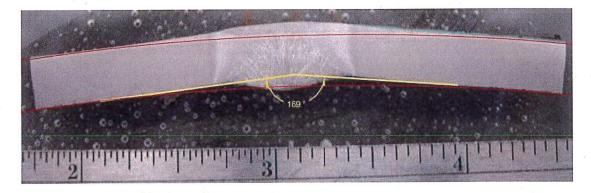


Figure A4. Photograph of the mounted cross-section (Mount M4) removed from U/S Joint, -1.54 ft from the U/S GW.

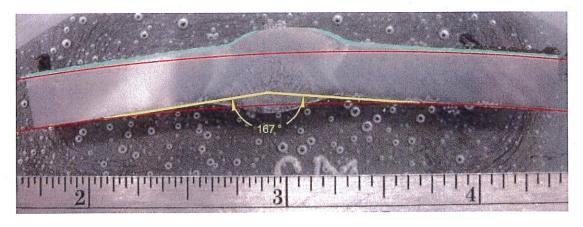


Figure A5. Photograph of the mounted cross-section (Mount M3) removed from D/S Joint, 28.19 feet from the U/S GW.

MPI Indications

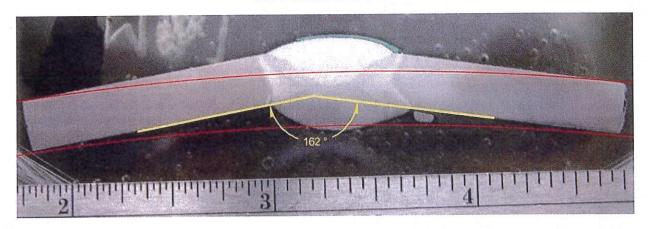


Figure A6. Photograph of the mounted cross-section (Mount M1) removed from MPI Indications 1a/1b, 18.81 feet from the U/S GW.

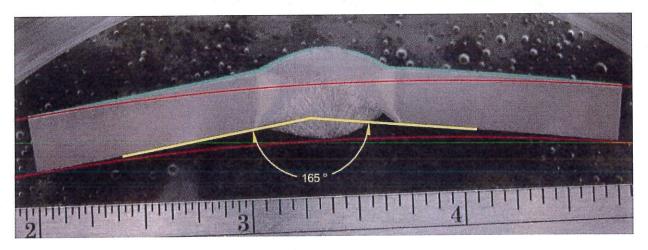


Figure A7. Photograph of the mounted cross-section (Mount M2) removed from MPI Indication 2, 23.83 feet from the U/S GW.

APPENDIX B

CorLASTM Analysis

APPENDIX B

Description of CorLAS™

The CorLASTM computer program was developed by Det Norske Veritas (U.S.A.), Inc. (formerly CC Technologies) to evaluate crack-like flaws in pipelines based on inelastic fracture mechanics. Using the effective area of the actual, measured crack length-depth profile, an equivalent semi-elliptical surface flaw is modeled and used to compute the effective stress and the applied value of J for internal pressure loading. The effective stress and applied J are then compared with the flow strength (\mathcal{O}_{fs}) and fracture toughness (J_{C}), respectively, to predict the failure pressure.

The program also contains a similar inelastic fracture mechanics analysis for through-wall flaws. The fracture toughness of the steel can be estimated from Charpy data or measured by means of a J_{IC} test. In the most recent version of CorLASTM, the fracture toughness analysis automatically checks for plastic instability and only the fracture toughness curve needs to be considered for crack-like flaws. The actual tensile and Charpy properties of the pipe joint, measured from the samples removed, can be used for the critical leak/rupture length calculation.

Case 1: Measured mechanical base-metal properties, measured dimensions, and the asmeasured flaw profile of Region 1 (Fatigue).

Shell SVJ 24"	Semi-Elliptical Flaw Profile			
	Base Metal			
	Maximum Operating Pressure (psig)	936		
	UTS (psi)	87800		
	YS (psi)	70300		
	FS (psi)	79050		
	E (ksi)	29500		
1 1100	nexp	0.089		
	Jc (lb/in)	3068		
	Thin-wall (OD) formula for hoop stress			
	Tmat	49.3		
	OD (in.)	24		
	Wall Thickness (in.)	0.260		
Summary of Result	s for Effective Area Method		-	
Ourillary of Nesalt	Flaw: Start (in.)	0.50		
	Length (in.)	6.75		
	Area (in.^2)	0.464		
	Depth (in.) Maximum	0.097		
	Equivalent Flaw	0.088		
Δ	For Design Factor	0.72		
	Design Pressure (psig)	1096.68		
	Failure Stress (psi)	65598		₩
	Failure Pressure (psig)	1421.28		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	1023.32		
Critical and Safe Pr	essure for a Crack			
	At operating pressure: J (lb/in)	43.3		4.9
	At operating pressure. 3 (ID/III)	40.0		4.0
	For Jc (lb/in)	3068.0	Tmat	49.3
	Predicted Critical Pressure (psig)	1413.18		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	1017.49		
	Based on J Fracture Toughness (Jc) criterion			
	Flaw: Start (in.)	0.50		
~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~	Length (in.)	6.75		
	Area (in.^2)	0.464		
	Depth (in.): Maximum	0.097		
	Equivalent Flaw	0.088		

Case 2: Measured mechanical base-metal properties, measured dimensions, and the asmeasured flaw profile of Region 1 (Fatigue) + Region 2 (Step-Wise Cracking).

Shell SVJ 24"	Semi-Elliptical Flaw Profile			
011011 0110 11	Base Metal			
	Maximum Operating Pressure (psig)	936		
	UTS (psi)	87800		
	YS (psi)	70300		
	FS (psi)	79050		
	E (ksi)	29500		*
	nexp	0.089		
	Jc (lb/in)	3068		
	Thin-wall (OD) formula for hoop stress			
	Tmat	49.3		
	OD (in.)	24		
	Wall Thickness (in.)	0.260		
Summary of Results	for Effective Area Method			
	Flaw: Start (in.)	1.00		
	Length (in.)	5.00		
	Area (in.^2)	1.010		
	Depth (in.) Maximum	0.210		
	Equivalent Flaw	0.234		
	For Design Factor	0.72		
	Design Pressure (psig)	1096.68		
	Failure Stress (psi)	35994		
	Failure Pressure (psig)	779.86		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	561.5		
Critical and Safe Pres				
	At apprehing processing 1 (lb/ip)	37199.3	Т	
	At operating pressure: J (lb/in)	37 199.3		_
	For Jc (lb/in)	3068.0	Tmat	49.3
	Predicted Critical Pressure (psig)	658.13		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	473.85		
T	December 15 and			
	Based on J Fracture Toughness (Jc) criterion			
	Flaw: Start (in.)	1.75		
	Length (in.)	3.50		
	Area (in.^2)	0.684		
-	Depth (in.): Maximum	0.210		
	Equivalent Flaw	0.249		

Case 3: Measured mechanical HAZ properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue).

Shell SVJ 24" Semi-Elliptical Flaw Profile			
HAZ			
Maximum Operating Pressure (psig)	936		
UTS (psi)	85700		
YS (psi)	70300		
FS (psi)	78000		
E (ksi)	29500		
nexp	0.083		
Jc (lb/in)	3000		
Thin-wall (OD) formula for hoop stress			
Tmat	49.7		
OD (in.)	24		
Wall Thickness (in.)	0.260		
Summary of Results for Effective Area Method		_	
Flaw: Start (in.)	0.50		
Length (in.)	6.75		
Area (in.^2)	0.464		
Depth (in.) Maximum	0.097		
Equivalent Flaw	0.088		
For Design Factor	0.72		
Design Pressure (psig)	1096.68		
Failure Stress (psi)	64726		
Failure Pressure (psig)	1402.41		
For Design Factor	0.72	_	
Maximum Safe Pressure (psig)	1009.73		
Critical and Safe Pressure for a Crack	1000.70		
At an exating process (/ lb/in)	41.7	T	4.7
At operating pressure: J (lb/in)	41.7		4.7
For Jc (lb/in)	3000.0	Tmat	49.7
Predicted Critical Pressure (psig)	1394.41		
For Design Factor	0.72		
Maximum Safe Pressure (psig)	1003.97		
Based on J Fracture Toughness (Jc) criterion		(2)	
Flaw: Start (in.)	0.50		
Length (in.)	6.75		
Area (in.^2)	0.464		
Depth (in.): Maximum	0.097		
Equivalent Flaw	0.088		

Case 4: Measured mechanical HAZ properties, measured dimensions, and the as-measured flaw profile of Region 1 (Fatigue) + Region 2 (Step-Wise Cracking).

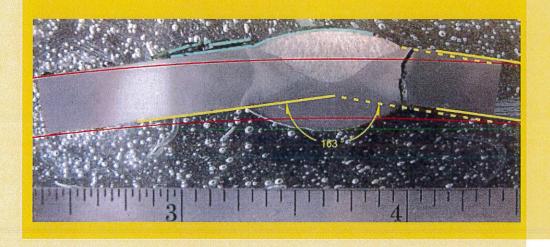
Shell SVJ 24"	Semi-Elliptical Flaw Profile			
	HAZ			
	Maximum Operating Pressure (psig)	936		
	UTS (psi)	85700		
	YS (psi)	70300		
	FS (psi)	78000		
	E (ksi)	29500		
The state of the s	nexp	0.083		
	Jc (lb/in)	3000		
	Thin-wall (OD) formula for hoop stress			
	Tmat	49.7		
	OD (in.)	24		
	Wall Thickness (in.)	0.260		
	Train Trinoration (i.i.i)			
Summary of Result	s for Effective Area Method	=,		
Carrinary of Freduct	Flaw: Start (in.)	1.00		
	Length (in.)	5.50		
	Area (in.^2)	1.010		
	Depth (in.) Maximum	0.210		
	Equivalent Flaw	0.234		
	For Design Factor	0.72		
3	Design Pressure (psig)	1096.68		
	Failure Stress (psi)	35516		
	Failure Pressure (psig)	769.50		
	For Design Factor	0.72		
	Maximum Safe Pressure (psig)	554.04		
Critical and Safe Pr		004.04		7
Cilical and Sale Fi	essure for a Grack			
	At operating pressure: J (lb/in)	20361.8	T	5938.4
	At operating pressure, a (ib/in)	20001.0		0000.4
	For Jc (lb/in)	3290.3	Tmat	54.5
	Predicted Critical Pressure (psig)	663.78	IIIat	34.0
	For Design Factor	0.72		
		477.92		-
	Maximum Safe Pressure (psig)	411.92		
	Deced on 1 Freeture Toughness (10)	- 2		
	Based on J Fracture Toughness (Jc) criterion			
	Flaw: Start (in.)	1.25		
	Length (in.)	4.25		
	Area (in.^2)	0.817		
	Depth (in.): Maximum	0.210		
	Equivalent Flaw	0.245		

ABOUT DNV GL

Driven by our purpose of safeguarding life, property, and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping our customers make the world safer, smarter, and greener.



SJV 24-INCH MAY 20TH, 2016 LOPC RCA REPORT



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October 2016

AGENDA

- Summary of RCA
- Timeline of Events
- Summary of the Failure Analysis Results
- Summary Cause and Effect Diagram
- Explanation of the Metallurgical Causes
- ILI Vendor Selection and Performance
- Recommendations
- Background
 - DNV GL Failure Analysis Report
 - Detailed Timeline
 - Cause and Effects Diagram

SUMMARY OF THE RCA

On May 20th, 2016, a rupture occurred on the Tracy to Windmill section of the SJV pipeline system. This rupture occurred due to a fatigue crack that developed and grew to failure and was not reported by the UT-C ILI survey.

The fatigue crack developed and grew to failure during transportation and/or in-service. The peaked geometry of the longitudinal seam weld, operational pressure cycling, inclusions in the pipe steel, and potentially an environmental factor played a role in the growth of the crack.

A feature was "detected, identified and... classified as a crack-like in long seam" at the location of failure in the automatic report following the UT-C survey. During manual review of the data by Rosen, "an incorrect amplitude was selected." Because of this "the Analyst overruled the [automated] call with the lower depth of 0.013 inch" (5%). This ultimately led to Rosen not reporting the feature.

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October 2016

- 1982 Pipe was manufactured by ARMCO in Houston, TX for Columbia Gas and shipped to Northeastern US
- 1988 Pipe was purchased by Texaco from Columbia Gas and shipped from the Northeastern US to Coalinga, California
- 1989 Pipe was installed at Tracy to Windmill Farms (3.05 miles)
 - Also installed at Coalinga to Mack Hill (3.4 miles of 5.9 mile segment) and Butts Road to Gustine (6.1 miles of 7.2 mile segment)
- April 1990 Pipeline hydrotested to 1,181 psig, held for four hours
- 1998 to 2015 Multiple MFL and caliper surveys performed
- 6/6/1998 02:35 PST Pipe failure approximately one mile downstream of Tracy in pipe body
- = 5/25/15 Pump Fire at Tracy
 - Heat and pressure from the incident is not thought to have affected the pipeline segment

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- 9/16/15 at 23:35 CDT Rupture occurred on the 24" section of piping 1,829 feet downstream of Tracy Station
 - Subsequent failure analysis determined the pipe section ruptured at a preexisting fatigue crack that initiated at the toe of the double submerged arc weld (DSAW)
- 9/21/15 Pipeline operation commenced at a temporarily reduced pressure of to 724 psig
 - 80% of 905 psig the pressure at the time of the 9/16/2015 LOPC
- 12/3/2015 Rosen MFL-C survey performed on the pipeline
- 12/4/2015 Rosen UT-C survey performed on the pipeline
- 3/7/2016 Final MFL-C report provided to SPLC showing:
 - No crack-like or other anomalies necessitating immediate action or any additional repairs required per SPLC Anomaly Response Table.

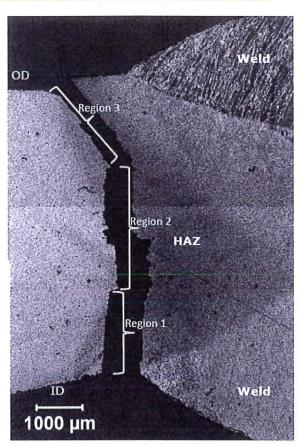
- 4/11/2016 Draft Preliminary UT-C Report received from Rosen
 - Resulted in two excavations based on 180-day conditions from the SPLC Anomaly Response Table
- 4/25/2016 Preliminary UT-C report received from Rosen.
 - No additional features reported that met the SPLC Anomaly Response Table
- 5/2/2016 Final UT-C report provided to SPLC showing:
 - No crack anomalies necessitating immediate action per the SPLC Anomaly Response Table
 - Two conditions reported by Rosen classified as 180 day conditions by SPLC
 - Scheduled for excavation based on 4/11/2016 Draft Preliminary Report

- 5/9/2016 Based on the MFL-C and UT-C surveys confirming the absence of any actionable defects, the recommendation was made by SPLC Engineering to remove the operating pressure reductions on three North Heavy segments with 24-inch Armco pipe.
- 5/16/2016 Statement of Fitness to remove the 20% pressure reduction was approved
- 5/17/2016 20% pressure reduction was removed and original 936 psig MOP re-instated
- 5/20/2016 00:35:55 PDT Pipeline failed 4,013 feet downstream of Tracy Station
- 5/22/2016 Failed pipe joint was replaced with 24-inch pipe
- 6/9/2016 Spike (1,170 psig) and 8-hour hold (1,070 psig) hydrotest was successful
- 7/19/2016 Pipeline restarted at a new MOP of 850 psig

SUMMARY OF FAILURE ANALYSIS

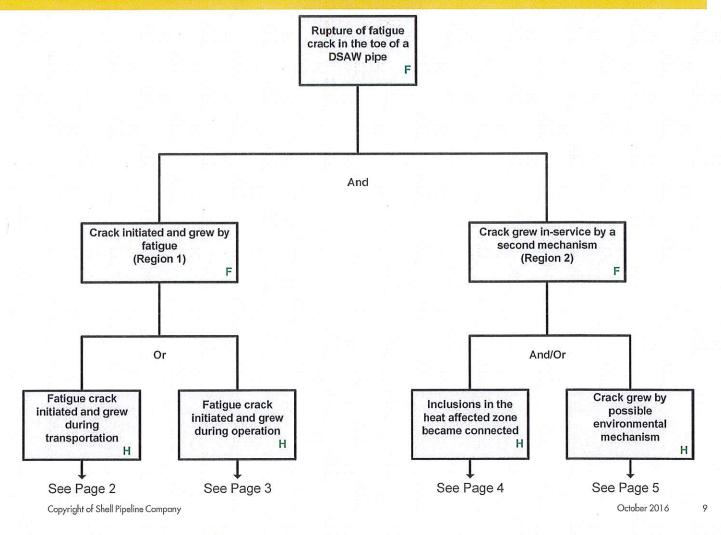
- DNV GL in Columbus, OH performed the metallurgical failure analysis. The pipe section ruptured at a preexisting fatigue crack that initiated at the toe of the double submerged arc weld (DSAW) and exhibited three distinct regions:
 - Region 1 a crack region at the internal surface with a maximum depth of 0.097 inches (37.3% of 0.260 inches nominal wall thickness) caused by fatigue;
 - Region 2 a crack region with a stair-stepped appearance, beginning at the end of Region 1, resulting from higher stress intensity factor at the crack tip as the crack propagated deeper into the material and possibly an environmental component. The maximum depth of this region is 0.210 inches (80.8% of 0.260 inches nominal wall thickness);
 - Region 3 the remaining ligament that overloaded during the rupture event.

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DNV GL Mount M6

CAUSE AND EFFECT - HIGH LEVEL



REGION 1 - FATIGUE CRACK INITIATION AND GROWTH

- Transport Fatigue
 - Pipe was susceptible to transport fatigue
 - Pipe was transported multiple time
 - Pipe had a peaked geometry that acted as a stress riser
- In-Service Fatigue
 - Cracks initiated at corrosion micro-pits at the inner diameter surface of the pipe
 - Pipeline has aggressive pressure cycling
 - Pipe had a peaked geometry that acted as a stress riser

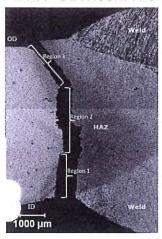
DNV GL concluded that "the fatigue crack initiation and propagation most likely occurred while in service. However, transit fatigue during transportation of the pipe cannot be ruled out as a contributing factor"

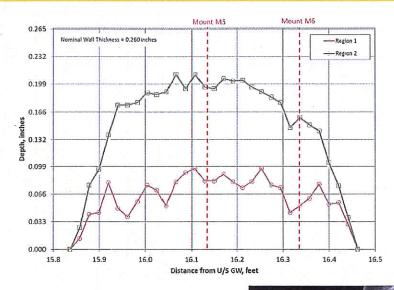
REGION 2 - CONTINUED CRACK GROWTH

- A combination of three different factors contributed to changing how the crack grew in service and had a different appearance from Region 1
- 1. Linkage of inclusions through pressure cycling of the pipeline
- 2. Higher stress at crack tip
 - Higher stress intensity as crack penetrated deeper
 - Peaked geometry of the weld
- 3. Possible environmental mechanism

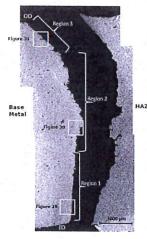
PRE-EXISTING FLAW PROFILE

DNV GL Mount M5









Length = 6.96 inches

Maximum depth of Region 1 = 0.097 inches (37.3% of nominal)

Maximum depth of Region 1 and 2 = 0.210 inches (80.8% of nominal)

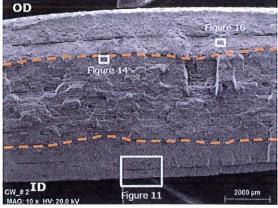
Average wall thickness for Failed Joint = 0.275 inches

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Region 3 (Rupture)

Region 2

Region 1



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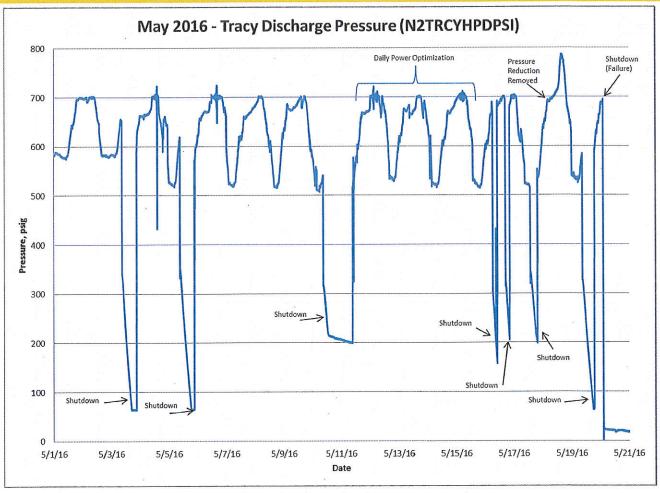
TRANSPORTATION FATIGUE

- Pipe with a diameter to wall thickness ratio greater that 50 is susceptible to transport fatigue per API 5L1
 - Failed joint had a ratio of 92.
- Pipe was transported multiple times
 - Transported from Armco (Houston, TX) to the Northeastern US
 - Likely the Delaware, Maryland, or Pennsylvania area (Columbia Gas)
 - Purchase records show API 5L1 Recommended Practices was followed
 - Transported from the Northeastern US to Coalinga, CA
 - Verbal information indicates that API 5L1 would have been specified per industry norms, written records have not been located
- Pipe had a peaked geometry that acted as a stress riser

PIPELINE OPERATIONS - PRESSURE CYCLING

- Pressure cycling is a significant factor in the development and growth of fatigue cracks
- Pipeline had "aggressive" pressure cycles in accordance with Baker TT05 reference standard
 - Daily power optimization leads to pressure cycling
 - ~300 psig (23% SMYS) daily pressure change at original MOP of 936 psig (32% of MOP)
 - ~200 psig (15% SMYS) daily pressure change with 20% pressure reduction from 936 psig MOP (21% of MOP)
 - Shutdowns lead to pressure cycling
 - ~850 psig (65% SMYS) pressure change during shutdown at original MOP of 936 psig (91% of MOP)
 - ~650 psig (50% SMYS) pressure change during shutdown with 20% pressure reduction from 936 psig MOP (69% of MOP)

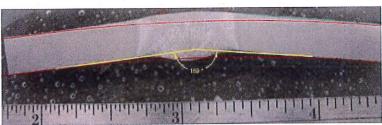
PIPELINE OPERATIONS - PRESSURE CYCLING (2)



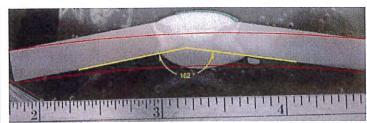
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PEAKED GEOMETRY



DNV GL Mount M7 - Unpeaked

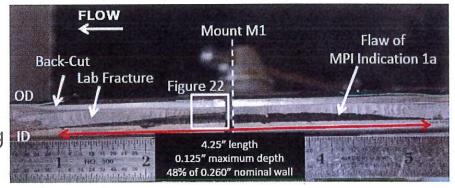


DNV GL Mount M1 - Peaked

- The "peaked" geometry of the DSAW was a causal factor for Region 1 and Region 2 for each hypothesis reviewed in the cause and effect diagram
- Quality control and quality assurance from the pipe mill should have identified the "peaked" geometry
- The "peaked" weld had a deformation of approximately 0.5% which is below the reporting threshold of traditional deformation ILI tools (1%)
 - The "peaked" seam would be considered a sharp contour and difficult to detect in larger diameter pipe using traditional geometry ILI surveys

ADDITIONAL FEATURE IN SAME PIPE JOINT AS FAILURE

- Three additional indications were identified through magnetic particle inspection
- MPI 1a exhibited similarities to the main feature with a Region 1 and Region 2
 Found to be 4.25 inches long and 0.125 inch (48%) deep
 - Was not reported by the ILI vendor in any report
 - Meets the stated detection threshold of UT-C survey
- MPI 1b and 2 were over-fill or under-fill respectively



DNV GL Mount M1

ILI VENDOR SELECTION

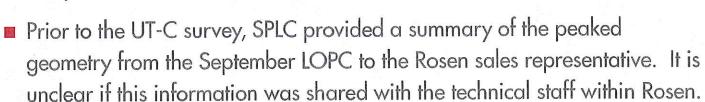
- A recommendation from the September 2015 LOPC RCA on Tracy to Windmill Farms was to perform a crack detection ILI survey
 - This recommendation applied to the three segments that have ARMCO pipe of similar vintage
- Rosen could perform both MFL-C and UT-C surveys
 - MFL-C can give a second opportunity to review the longitudinal seam weld for crack-like features

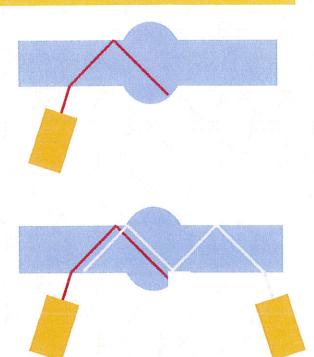
ILI VENDOR PERFORMANCE (1)

- Per Rosen, an "anomaly in joint 1250 was detected, identified, and boxed. It was classified as a crack-like in long seam" with the automated sizing process
 - Odometer 4073.718, 7.594 inch long and 0.150 inch (57.7%) deep
- Due to the volume of features that required review by the analysts, Rosen elected to modify their process for review of features. This included changing the amplitude that was used for signal review
 - No management of change or equivalent process was utilized within Rosen and SPLC was not consulted
- Per Rosen, "during sizing an incorrect amplitude was selected. Anomaly depth was calculated at < 0.08 inch"</p>
 - Rosen believed that the reporting threshold was 0.08 inch
 - At Odometer 4073.718, per Rosen, "the Analyst overruled the [automated] call with the lower depth of 0.013 inch" (5%)
- No feature was reported at the location of the failure

ILI VENDOR SELECTION AND PERFORMANCE (2)

- Rosen has stated...
 - "The acoustics of DSAW long seams are complex. This is due to a parabolic reflection of the weld cap/crown"
 - "A strong signal is generated when the beam is reflected in itself"
 - "Mill grinding or repair cause a locally shifted self-reflection"
 - "Edge or root reflections occur, but are only visible from one side"





ROSEN JOINT 1250 SUMMARY

DATA EVALUATION ANOMALIES DETECTED **IN JOINT 1250**



Manual Depth Sizing

Distance [feet]	Length [inch]	Angel [deg] [degree]	Туре	MAX_AMPL [dB]	ABSDEPTH [inch]
4072.566	9.938	260.977	CRAC-LIKE	40.200	0.000
4073.718	7.594	261.033	CRAC-LIKE	42.800	0.013
4076.638	5.442	262.530	CRAC-LIKE	43.400	0.017
4081.677	3.245	261.556	CRAC-LIKE	45.200	0.032

Automated Depth Sizing

Distance [feet]	Length [inch]	Angel [deg] [degree]	Туре	MAX_AMPL [dB]	ABSDEPTH [inch]
4073.718	7.594	261.033	CRAC-LIKE	51.000	0.150
10					

The review of the data revealed a different depth for feature at 4073.718 ft based on the Automated Depth Sizing. The Analyst overruled the call with the lower depth of 0.013 in. This is typically done if the echo signal shows inconsistent pattern. This is subject for further investigation.

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RECOMMENDATIONS (APPROVED)

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#	Action	Due Date
	Integrity Management	
1	Enhancement of integrity program related to crack-like defects. Enhance process for identifying lines to survey, tool selection, vendor verification, run acceptance, and response. This item is procedural changes to be in place for 2017 crack detection surveys. This item will also serve to modify the seam susceptibility algorithm for of all seam types (e.g. DSAW, high frequency ERW, etc.)	12/15/16
2	Review pipelines with aggressive pressure cycling to determine: (1) if additional integrity assessment is required (i.e. ILI crack detection or hydrotest) and (2) if any operational modifications can be made to reduce the pressure cycle severity	12/15/16
3	Review previous ILI data in ARMCO pipe to determine if peaking can be identified in those surveys	12/15/16
4	Determine the reassessment interval for the ARMCO pipe in the SJV system for (1) ILI reassessment, and (2) hydrotest	12/15/16
	Product Quality Testing	
5	Confirm how frequently corrosiveness testing (CO2, H2S, pH, BS&W, etc.) in pipelines is performed	12/15/16
	Pipeline Operations	
6	End the practice of daily power optimization on SJV system	Complete
7	Install MOVs at Los Banos and Kamm to eliminate the necessity for shutdowns of adjacent segments when Los Banos and Kamm are shutdown	7/1/17
8	Review operating procedure related to planned shutdowns to identify opportunities to limit the magnitude or pressure cycling that occur on the North Heavy System	12/15/16
9	Develop a list of pipelines that are aggressively cycled and what is being done about the cycling. There needs to be corporate awareness for what pressure cycling does to the pipelines. This action needs to lead to more discipline and visibility of the issue	12/15/16
10	Continuously improve the process by ensuring there is documentation following a PL-1115 adjustment to set points that the notification is closed out by the technician following the implementation of changes	3/31/17

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