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

Investigators	Jon Manning, Noah Matthews
Region Director	R.M. Seeley
Date of Report	June 29, 2012
Subject	Failure Investigation Report – Shell Houma to Houston (Ho-Ho) Pipeline

Operator, Location, & Consequences

Date of Failure	11/16/2010
Commodity Released	Crude Oil
City/County & State	Calcasieu Parish, Vinton, Louisiana
OpID & Operator Name	31174, Shell Pipeline Company, LP
Unit # & Unit Name	50664, Houma District West
SMART Activity #	135866
Milepost / Location	MP 32.5 approximately 500 feet north of Intercoastal Waterway (ICW)
Type of Failure	Corrosion Fatigue Cracking
Fatalities	0
Injuries	0
Description of area impacted	Rural Marsh – Near the Intercoastal Waterway
Property Damage	$375,000

Executive Summary

On November 16, 2010, Shell Pipeline Company, LP (Shell, the Operator) reported a release on its Houma to Houston 22-inch crude oil pipeline system. The Operator's control center in Houston, Texas received a line balance alarm on the Erath to Port Neches pipeline segment at approximately 2:36 PM Central Standard Time (CST). The Operator immediately initiated a shut-down of the pipeline and began closing mainline block valves. By 2:41 PM CST the segment was isolated and personnel were dispatched to scout the pipeline segment for a release.

At approximately 4:44 PM CST a third party reported the location of the release to the Shell operations control center. Shell personnel confirmed the location of the release at approximately 5:15 PM CST and activated their Oil Spill Response Organization (OSRO) team approximately 15 minutes later. At 6:15 PM CST, Shell notified the National Response Center. The release was initially estimated by Shell to be approximately 1,500 barrels but was later revised to 1,030 barrels. The Operator established an incident command center (ICC) in Houston, TX on November 16 at approximately 7 PM CST and continued notifying law enforcement authorities and dispatching personnel to the release site to initiate the cleanup. There was no fire, explosion or injuries reported.

The release occurred on the Houma to Port Neches segment of the pipeline in a rural marsh area near pipeline Milepost 32.5 approximately 500 feet north of the Intercoastal Waterway (ICW). The metallurgical evaluation determined the rupture was caused by corrosion fatigue cracking that penetrated the pipe wall to the point that the remaining wall thickness was not able to withstand the hoop stress created by the internal pressure.

System Details

The Shell Pipeline Company, L.P., Houma to Houston pipeline system (Ho-Ho pipeline system) transports crude oil approximately 300 miles from Houma, LA to the Houston, TX area. A drawing of the Shell Ho-Ho pipeline system is included in Appendix A. The Ho-Ho pipeline has a nominal diameter of 22-inches from Houma, LA to Port Neches, TX and a nominal diameter of 20-inches from Port Neches to Houston. The pipeline traverses a rural unpopulated, relatively flat area of the Gulf coastal plain across Southwestern Louisiana and Southeast Texas and delivers crude oil to refineries in Louisiana and Texas. There are high consequence areas, high population areas, and commercially navigable waterways as defined by 49 CFR 195.450 along the pipeline route. The release occurred on the Houma to Port Neches segment of the pipeline in a rural marsh area near pipeline Milepost 32.5 approximately 500 feet north of the Intercoastal Waterway. This location is approximately 10 miles downstream of the Sulphur Booster Station near Vinton, LA. A map showing the approximate location of the release site is included in Appendix B.

Pipe Specifications

The pipeline segment where the release occurred consists of a 22-inch nominal diameter pipe manufactured by Kaiser Steel. The pipe is double submerged arc welded (DSAW) carbon steel with a 0.312 inch wall thickness, API Grade 5L, X52 installed in 1952. The pipeline was coated with coal tar enamel and equipped with an impressed current cathodic protection system. The pipeline MOP is 1,050 psig established by a hydrostatic test performed in 1995. The pipeline normally operates at 800 to 900 psig. The discharge pressure at Sulphur Booster Station at the time of the release was 840 psig and the pipeline pressure at the location of the release was approximately 700 psig. Shell performed an inline-inspection (ILI) in 2007 using Magnetic Flux Leakage (MFL) and Caliper tools. The ILI report did not indicate a required repair at the location of the incident, but did indicate the presence of corrosion with approximately a 10% wall loss where the failure occurred.

Events Leading up to the Failure

Shell indicates that the Ho-Ho pipeline was operating normally prior to the line balance alarm at 1:36 PM CST. No previous abnormal operations had been noted. The discharge pressure, up until the moment of the pipeline failure, recorded at the Sulphur Booster Station, was approximately 840 psig. The pressure at the site of the rupture was estimated by the Operator to be approximately 700 psig. Shell records indicate that the intake pressure at the Port Neches Booster Station downstream of the failure site had been consistently recorded at approximately 240 psig until the pressure dropped to 0 psig at approximately 1:35 PM CST. Operator records showing an event timeline, pressures at Sulphur and Port Neches Stations, and SCADA Event Summary are included in Appendix C.

Emergency Response

On November 16, 2010 at approximately 2:36 PM, the Shell Pipeline operator on duty at the control center in Houston, TX received a line balance alarm on the Erath to Port Neches pipeline segment. The controller observed an increase in flow and a decrease in pressure at the Sulphur booster station and low flow at the next downstream pump station located near Port Neches, LA. The Shell operator

immediately initiated a shut-down of the pipeline and began closing mainline block valves. By 2:41 PM CST the segment was isolated and personnel were dispatched to scout the pipeline segment for a release. The location of the release was called in to the Shell operations control center by a third party at approximately 4:44 PM CST. Shell personnel traveled the site and confirmed the location of the release at approximately 5:15 PM CST. The Shell Oil Spill Response Organization (OSRO) team was activated at approximately 5:26 PM CST and the Operator reported a worst-case release of 1,500 barrels to the NRC at 6:15 PM CST. A copy of the telephonic report made by Shell is included in Appendix D.

The Operator established an incident command center (ICC) in Houston, TX on November 16 at approximately 7 PM CST and continued notifying law enforcement and regulatory authorities as well as dispatching personnel to the release site to perform cleanup operations. Shell waited until daylight on November 17 to begin excavating the pipeline but experienced delays due to high levels of benzene detected at the rupture site. After allowing the benzene to dissipate, excavation of the pipeline revealed a "fish-mouth" rupture at approximately the 6 o'clock position. The Operator continued cleanup operations and began determining pipeline repair requirements November 17. Shell demobilized the Incident Command Center on November 18 and called the NRC to revise the release quantity to 1,030 barrels. A copy of the Shell Form 7000-1 report is included in Appendix E and photographs of the accident site are included in Appendix F.

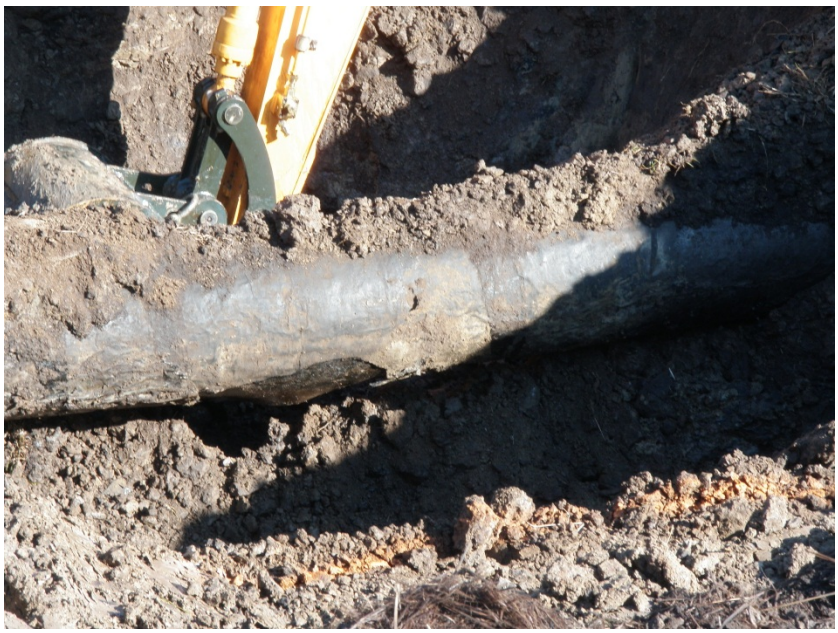


Photo 1: Failed Section with Opening at 6 o'clock position

Summary of initial start-up plan and return-to-service

The operator initiated the pipeline repair on November 20 based on a plan determined to be acceptable by PHMSA. PHMSA also worked with Shell personnel to develop an acceptable safe startup plan. Shell agreed to evaluate their pipeline system to determine if any other similar integrity threatening conditions may exist by reevaluating previous In-Line Inspection (ILI) data and performing an additional

ILI with a tool more capable of detecting longitudinal flaws. Pipeline repairs were completed on November 21 and the pipeline was refilled and restarted on November 24, 2010.

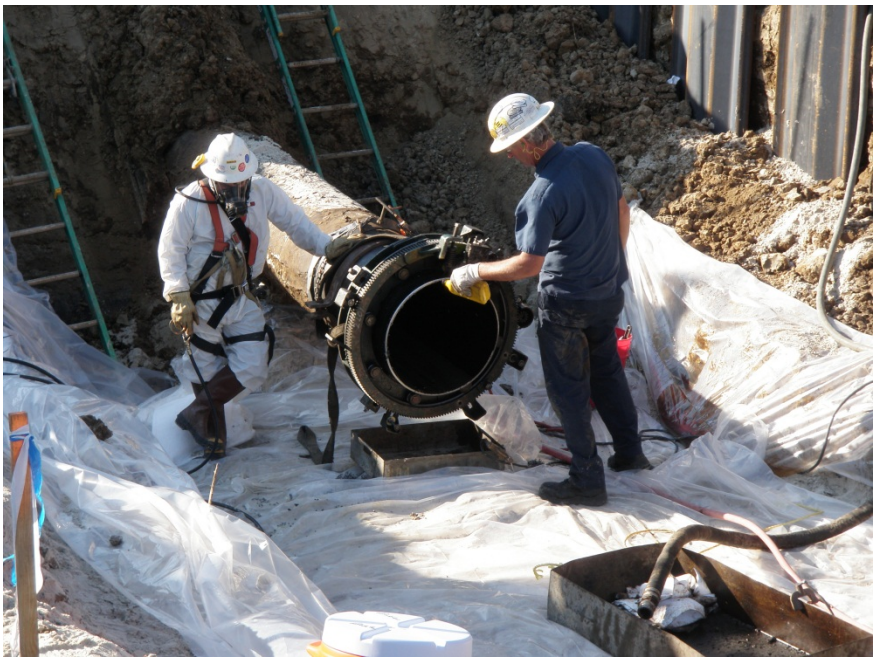


Photo 2: Flanged Repair

Investigation Details

The accident occurred on the Houma to Port Neches segment of the pipeline in a rural, unpopulated area approximately 10 miles downstream of the Sulphur Booster Station, in Calcasieu Parish near Vinton, LA. The pipeline rupture occurred 500 feet north of the Intercoastal Waterway (ICW), Latitude 30° 03' 38" N, Longitude 093° 33' 04" W.

The failed pipeline segment was removed by cold cutting, packaged for transport, and shipped to Stork Testing & Metallurgical Consulting, Inc., in Houston, TX for analysis. The failure occurred in an under bend at approximately the 6 o'clock position where, according to the Stork metallurgical analysis, the coating likely disbonded allowing the onset of corrosion. Evidence was also found of multiple fatigue cracks that initiated in the deeper corrosion pits. The operational history of the pipeline indicates that the pipeline is subject to cyclical loading due to batched shipments of crude oil. The metallurgical analysis concluded the fatigue cracks that initiated in the corrosion pits weakened the wall of the pipe so that it could not withstand the hoop stress created by the internal pressure, resulting in the rupture. A copy of the Stork metallurgical report is included in Appendix G.

Examination of Operator records indicated that in 2007, Shell ran an inline-inspection (ILI) using Magnetic Flux Leakage and Caliper tools. The ILI indicated corrosion at the failure location but grading by the vendor indicated that the wall loss was minimal (approximately 10%) and the Operator did not excavate the site. A review of the pipeline operations taking place immediately prior to the accident did

not indicate the pipeline was being operated outside of the design parameters or that any abnormal operations had occurred.

Findings & Contributing Factors

A "fish mouth" rupture occurred at the 6 o'clock position on the pipeline and was approximately 36.25 inches long with a width of 4.75 inches at the widest point and was 90 degrees from the longitudinal weld. The Stork metallurgical analysis determined that the rupture occurred approximately 15-1/2 inches from the apex of an under bend in the pipeline. Circumferential wrinkles at regular intervals on the inside surface of the pipe indicated that the bend was likely made in the field which may have caused the coating to disbond at the failure location. Heavy corrosion was found on the outside surface of the pipe at the failure site and semi-elliptical crack surfaces characteristic of fatigue cracks were found the fracture faces. The operational history indicates that the pipeline has been subjected to cyclic loading. Testing of the pipe materials did not reveal any manufacturing defects and showed satisfactory tensile properties consistent with the grade of pipe. Tests of the corrosion deposits were found to have bacteria that can result in Microbiologically-Influenced Corrosion (MIC) but the metallurgical analysis did not make any conclusions as to whether MIC contributed to the external corrosion. The metallurgical analysis concluded that the failure resulted from fatigue cracks that initiated in the corrosion pits reducing the strength of the pipe so that it could not contain the hoop stress resulting from the internal pressure.

Photo 3: Failed "fish-mouth" section of pipe

Appendices

A Drawing of Shell Ho-Ho Pipeline System

B Pipeline Map Showing Approximate Accident Location

C Events Timeline and Pump Station Pressures, SCADA Event Summary

D Telephonic Notice Report – NRC #960033

E PHMSA Form 7000-1 Accident Report Prepared by Shell – No. 10100287

F Accident Site Photos and Diagrams

G Stork Metallurgical Report

Appendix A, B, C and G

These documents are on file at PHMSA

Appendix D – NRC Report – No. 960033

The following NRC report is forwarded for your situational awareness. CMC 6-1863

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.

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 # 960033

INCIDENT DESCRIPTION

*Report taken by: MST2 JAQUELINE ARSENAULT at 19:15 on 16-NOV-10
Incident Type: PIPELINE
Incident Cause: EQUIPMENT FAILURE
Affected Area: MARSH
Incident was discovered on 16-NOV-10 at 17:15 local incident time.
Affected Medium: WATER MARSHY AREA

REPORTING PARTY
Name: BRAD HUBBARD
Organization: SHELL PIPELINE
Address: 701 POYDRAS
NEW ORLEANS, LA
SHELL PIPELINE reported for the responsible party.
PRIMARY Phone: (504)2848438 ALTERNATE Phone: (504)7283584
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY
Name: BRAD HUBBARD
Organization: SHELL PIPELINE
Address: 701 POYDRAS
NEW ORLEANS, LA
PRIMARY Phone: (504)2848438 ALTERNATE Phone: (504)7283584

INCIDENT LOCATION
County: CALCASIEU
City: VINTON State: LA
Latitude: 30° 03' 38" N
Longitude: 093° 33' 04" W
30 3' 38" N 93 33' 04" W

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

CRUDE OIL DISCHARGED FROM A PIPELINE DUE TO LINE FAILURE. THE QUANTITY DISCHARGED IS UNKNOWN AT TIME OF CALL. WORST CASE ESTIMATED
TO BE 1500 BARRELS.

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: DISTRIBUTION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN
---WATER INFORMATION---
Body of Water: MARSH
Tributary of: UNKNOWN
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

Closure Type	Description of Closure	Hours Closed	Direction of Closure
Air:	N		
Road:	N	Major Artery:N	
Waterway:			

N
Track:

Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

LINE WAS SHUT IN; ISOLATION VALVES CLOSED; OIL SPILL REMOVAL ORGANIZATION HAS BEEN CONTACTED
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: PARTLY CLOUDY, 60ºF Wind direction: NW

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: LA STATE POLICE
State/Local On Scene: NONE
State Agency Number: 10-06654

NOTIFICATIONS BY NRC

CALCASIEU PARISH SHERIFF'S DEPT (CRIMINAL INTELLIGENCE UNIT)
  16-NOV-10 19:24 (337)4913778
DHS NOC (NOC)
  16-NOV-10 19:24 (202)2828114
USCG ICC (ICC ONI)
  16-NOV-10 19:24 (301)6693363
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
  16-NOV-10 19:24 (202)3661863
U.S. EPA VI (MAIN OFFICE)
  (866)3727745
FLD INTEL SUPPORT TEAM NEW ORLEANS (SUPERVISOR, FIST NEW ORLEANS)
  16-NOV-10 19:24 (504)5894224
FLD INTEL SUPPORT TEAM PORT ARTHUR (FIST COMMAND CENTER)
  16-NOV-10 19:24 (409)7195005
FLD INTEL SUPPORT TEAM PORT ARTHUR (FIELD UNIT)
  16-NOV-10 19:24 (409)7195001
JFO-LA (COMMAND CENTER)
  16-NOV-10 19:24 (225)3366513
JFO-LA (FEMA JFO LA)
  16-NOV-10 19:24 (225)3366513
LA DEPT OF ENV QUAL (MAIN OFFICE)
  16-NOV-10 19:24 (225)2193640

LA DEPT OF WILDLIFE AND FISHERIES (ATTN: LAURA CARVER)
  16-NOV-10 19:24 (337)
LA GOV OFFICE HS AND EMERGENCY PREP (MAIN OFFICE)
  16-NOV-10 19:24 (225)9257500
LA OFFICE OF GOV (MAIN OFFICE)
  16-NOV-10 19:24 (225)2195800
LA OFFICE OF PUBLIC HEALTH (MAIN OFFICE)
  16-NOV-10 19:24 (888)2937020
MSU LAKE CHARLES (MAIN OFFICE)
  16-NOV-10 19:24 (337)4917800
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
  16-NOV-10 19:24 (202)2829201
NOAA RPTS FOR LA (MAIN OFFICE)
  16-NOV-10 19:24 (206)5264911
MSU PORT ARTHUR (MAIN OFFICE)
        (409)7236501
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
  16-NOV-10 19:24 (202)3660568
LA STATE POLICE (MAIN OFFICE)
  16-NOV-10 19:24 (225)9256595
TCEQ (MAIN OFFICE)
  16-NOV-10 19:24 (512)2392507

ADDITIONAL INFORMATION

CALLER INTENDS TO NOTIFY THE PARISH SHERIFF'S DEPARTMENT AND THE PARISH OFFICE OF EMERGENCY PREPAREDNESS.

*** END INCIDENT REPORT #960033 ***

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

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

Appendix E – PHMSA Form 7000-1 Accident Report – No. 10100287

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0047 EXPIRATION DATE: 01/31/2013

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Report Date:**	12/09/2010
	No.	20100287 - 15559 --- (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

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

INSTRUCTIONS

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

PART A - KEY REPORT INFORMATION

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

Last Revision Date:	02/01/2011
1. Operator's OPS-issued Operator Identification Number (OPID):	31174
2. Name of Operator	SHELL PIPELINE CO., L.P.
3. Address of Operator:	
3a. Street Address	777 WALKER, P.O. Box 2648 (TWO SHELL PLAZA)
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code	77252-2648
4. Local time *(24-hr clock)* and date of the Accident:	11/16/2010 16:46
5. Location of Accident:	
Latitude:	30.06066
Longitude:	-93.55077
6. National Response Center Report Number (if applicable):	960033
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	11/16/2010 16:46
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil
- Specify Commodity Subtype:	
- If "Other" Subtype, Describe:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend: %:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend (e.g. B2, B20, B100): B	
9. Estimated volume of commodity released unintentionally (Barrels):	1,030.00
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	526.00
11. Estimated volume of commodity recovered (Barrels):	1,021.00
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. Workers working on the right-of-way, but NOT associated with this Operator	
12e. General public	
12f. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT	

associated with this Operator	
13e. General public	
13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	11/16/2010 16:46
14b. Local time pipeline/facility restarted:	11/23/2010 09:17
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident:	11/16/2010 17:15
18b. Local time Operator resources arrived on site:	11/16/2010 17:15

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	Louisiana
3. Zip Code:	70668
4. City	Vinton
5. County or Parish	Calcasieu
6. Operator-designated location:	Milepost/Valve Station
Specify:	32.5
7. Pipeline/Facility name:	Erath to East Houston Crude
8. Segment name/ID:	Sulphur Station to Pt. Neches 22"
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):	69
12. Did Accident occur in a crossing?	No
- If Yes, specify below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

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

3a. Nominal diameter of pipe (in):	22
3b. Wall thickness (in):	.312
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	52,000
3d. Pipe specification:	X-52
3e. Pipe Seam , specify:	DSAW
- If Other, Describe:	
3f. Pipe manufacturer:	Kaiser Steel Corporation
3g. Year of manufacture:	1952
3h. Pipeline coating type at point of Accident, specify:	Coal Tar
- If Other, Describe:	
- If Weld, including heat-affected zone, specify:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	1952
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other, Describe:	
Approx. size: in. (widest opening) by	4.7
in. (length circumferentially or axially)	36.2
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	No
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	
- Terrestrial	
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	No
4. Anticipated remediation:	Yes
4a. If Yes, specify all that apply:	
- Surface water	
- Groundwater	
- Soil	Yes
- Vegetation	Yes
- Wildlife	
5. Water contamination:	No
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?	Yes
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	No
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's	

Integrity Management Program?	
- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated Property Damage :	
8a. Estimated cost of public and non-Operator private property damage	$ 25,000
8b. Estimated cost of commodity lost	$ 40,000
8c. Estimated cost of Operator's property damage & repairs	$ 375,000
8d. Estimated cost of Operator's emergency response	$ 524,000
8e. Estimated cost of Operator's environmental remediation	$ 25,000
8f. Estimated other costs	$ 0
Describe:	8c. Repairs - Pipeline cut out and replaced with new pipe.
8g. Total estimated property damage (sum of above)	$ 989,000

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	700.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	1,050.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5f. below)*	
5a. Type of upstream valve used to initially isolate release source:	Automatic
5b. Type of downstream valve used to initially isolate release source:	Manual
5c. Length of segment isolated between valves (ft):	109,296
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No
- If Yes, Which operational factors complicate execution? (*select all that apply*)	
- Excessive debris or scale, wax, or other wall buildup	
- Low operating pressure(s)	

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

PART F - DRUG & ALCOHOL TESTING INFORMATION

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

PART G – APPARENT CAUSE

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

Apparent Cause:	G1 - Corrosion Failure

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

External Corrosion:	Yes
Internal Corrosion:	
- If External Corrosion:	
1. Results of visual examination:	Localized Pitting
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	Yes
- If Other, Describe:	External corrosion and corrosion fatigue cracks initiated some deeper longitudinal corrosion features.
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	Yes
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	Yes
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	Yes
If Yes - Year protection started:	1952
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	Yes
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	Yes
If "Yes, CP Annual Survey" – Most recent year conducted:	2010
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	No
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	

- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	Yes
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	Yes
Most recent year:	2007
- Ultrasonic	
Most recent year:	
- Geometry	Yes
Most recent year:	2007
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	Yes
If Yes -	
Most recent year tested:	1995
Test pressure:	1,327.00
17. Has one or more Direct Assessment been conducted on this segment?	No
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	No
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	

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

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

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

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

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

5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	

G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column

Incorrect Operation – Sub-Cause:	
Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage	No
Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	No
1. Specify:	
- If Other, Describe:	
Valve Left or Placed in Wrong Position, but NOT Resulting in a Tank, Vessel, or Sump/Separator Overflow or Facility Overpressure	No
Pipeline or Equipment Overpressured	No
Equipment Not Installed Properly	No
Wrong Equipment Specified or Installed	No
Other Incorrect Operation	No
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	

- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

Evidence of External Corrosion at rupture point. Pipe is currently at a third party laboratory for full metallurgical testing to determine cause and contributing factors.

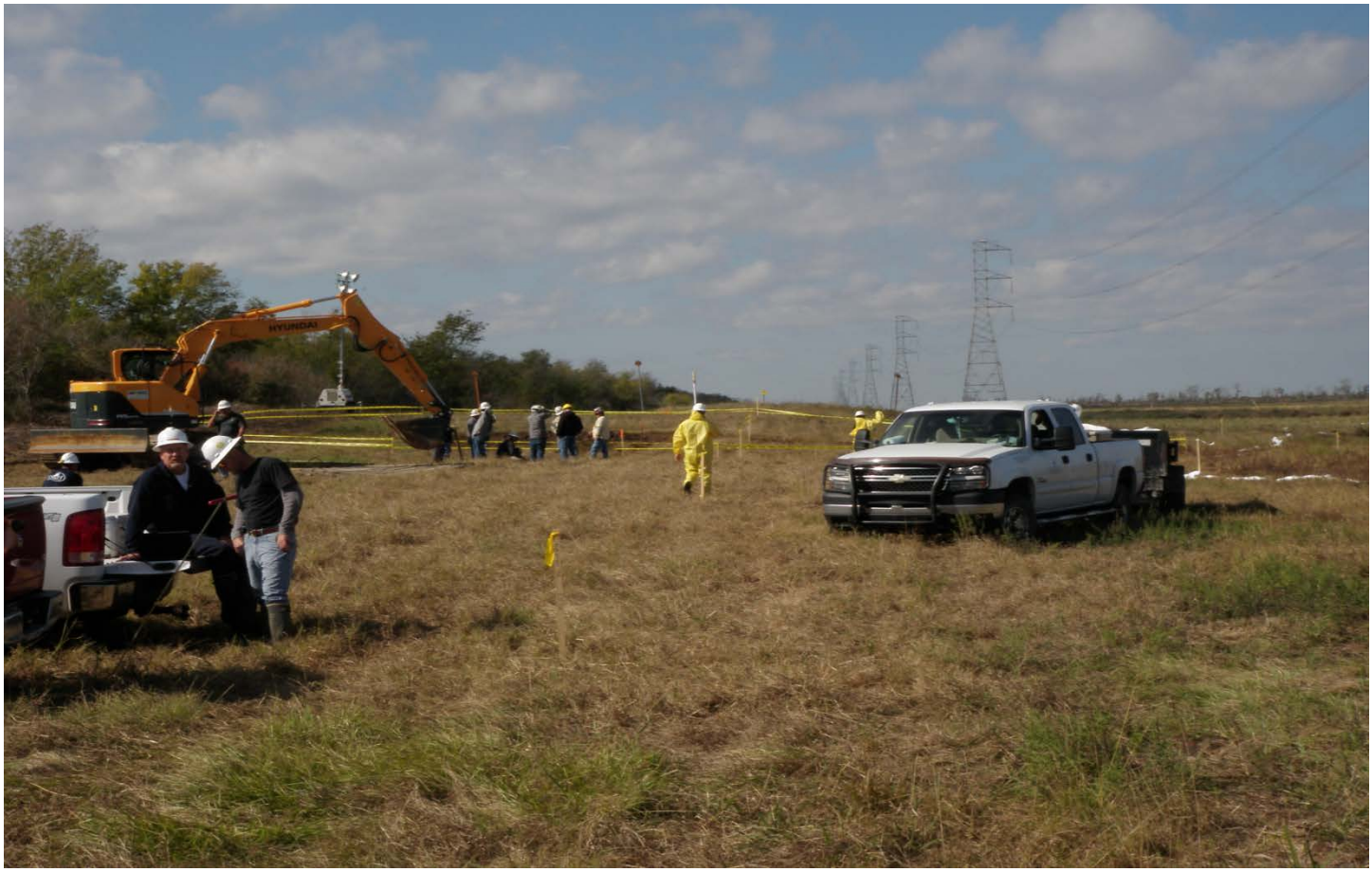
Note: NRC - Notification to the NRC was initially made at 16:46 11/16/2010. No information of location or volume was known. The NRC said to call back when more information is known and a report number will be given. Second call to the NRC was done at 18:10 11/16/2010 with the location of the release and a worst case scenario volume. Third call to the NRC was done at 12:20 11/18/2010 with the release volume.
Supplemental
2/1/2011 - The corrosion of the outside surface occurred at a bend in the pipe at which the corrosion coating was compromised. Circumferential wrinkles at regular intervals on the inside surface of the pipe indicated that the bend had been made in the field. Field bending of coated pipe could have disbonded the coating, eventually allowing contact with wet soil and allowing corrosion. Disbonded coating further reduces pipeline integrity because the cathodic protection of the pipeline to prevent corrosion is not effective at disbonded locations.

File Full Name

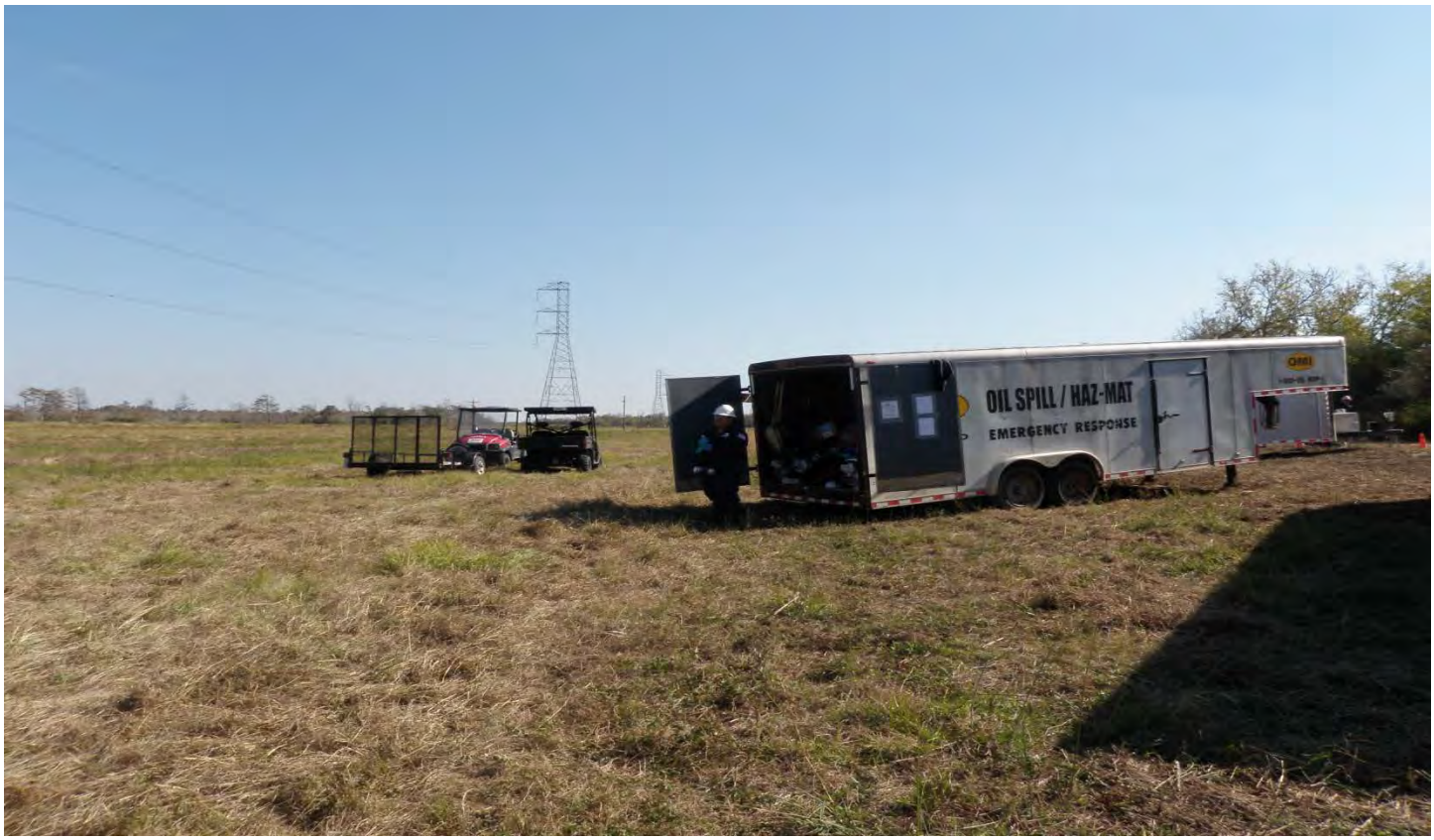
PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Richard Klasen
Preparer's Title	Asset Integrity Specialist
Preparer's Telephone Number	7132411064
Preparer's E-mail Address	Richard.Klasen@shell.com
Preparer's Facsimile Number	7132412997
Authorized Signature's Name	Brian Sitterly
Authorized Signature Title	Integrity and Regulatory Services Manager
Authorized Signature Telephone Number	7132413620
Authorized Signature Email	Brian.Sitterly@shell.com
Date	02/01/2011

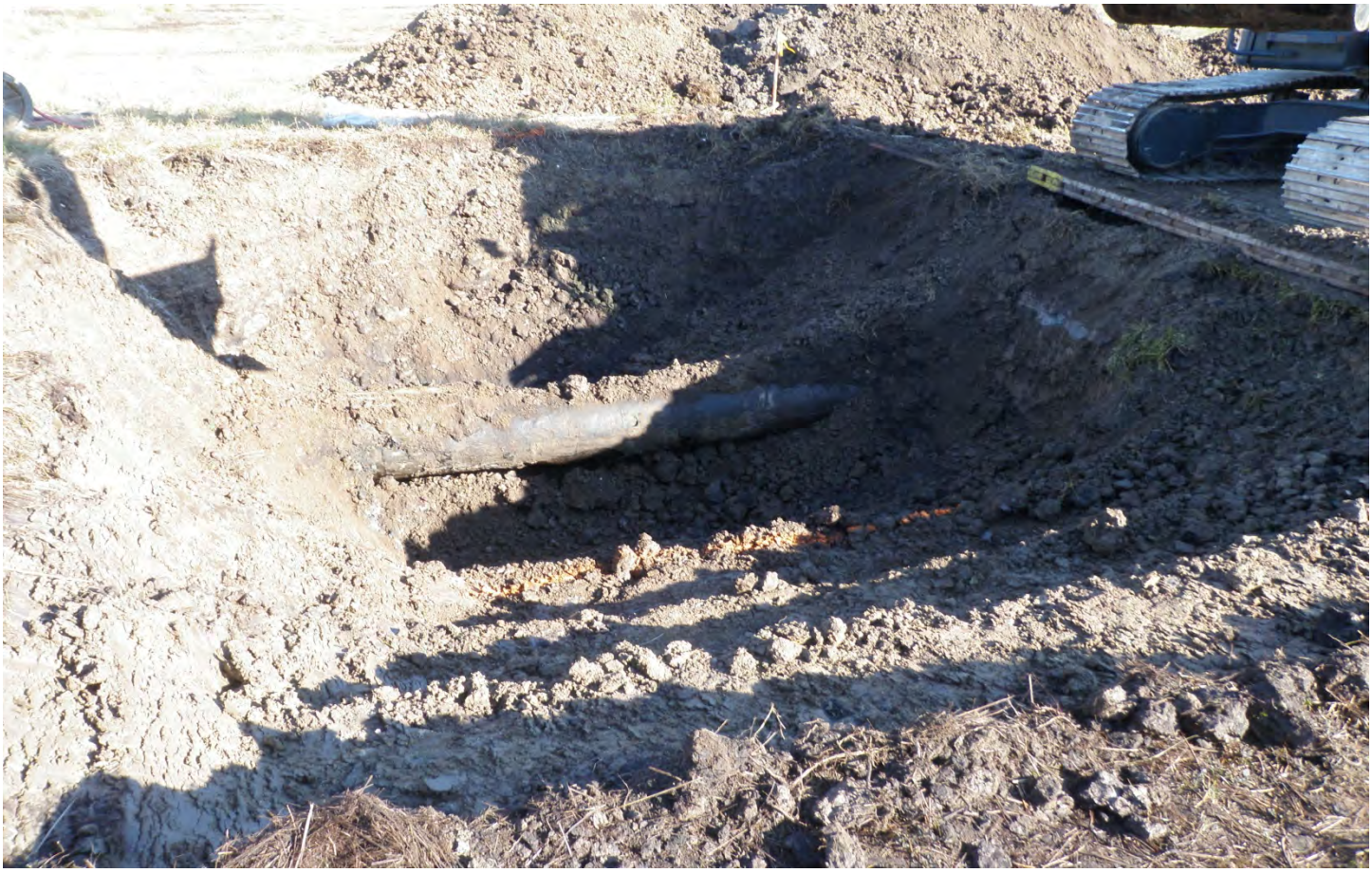
Appendix F – Accident Site Photos



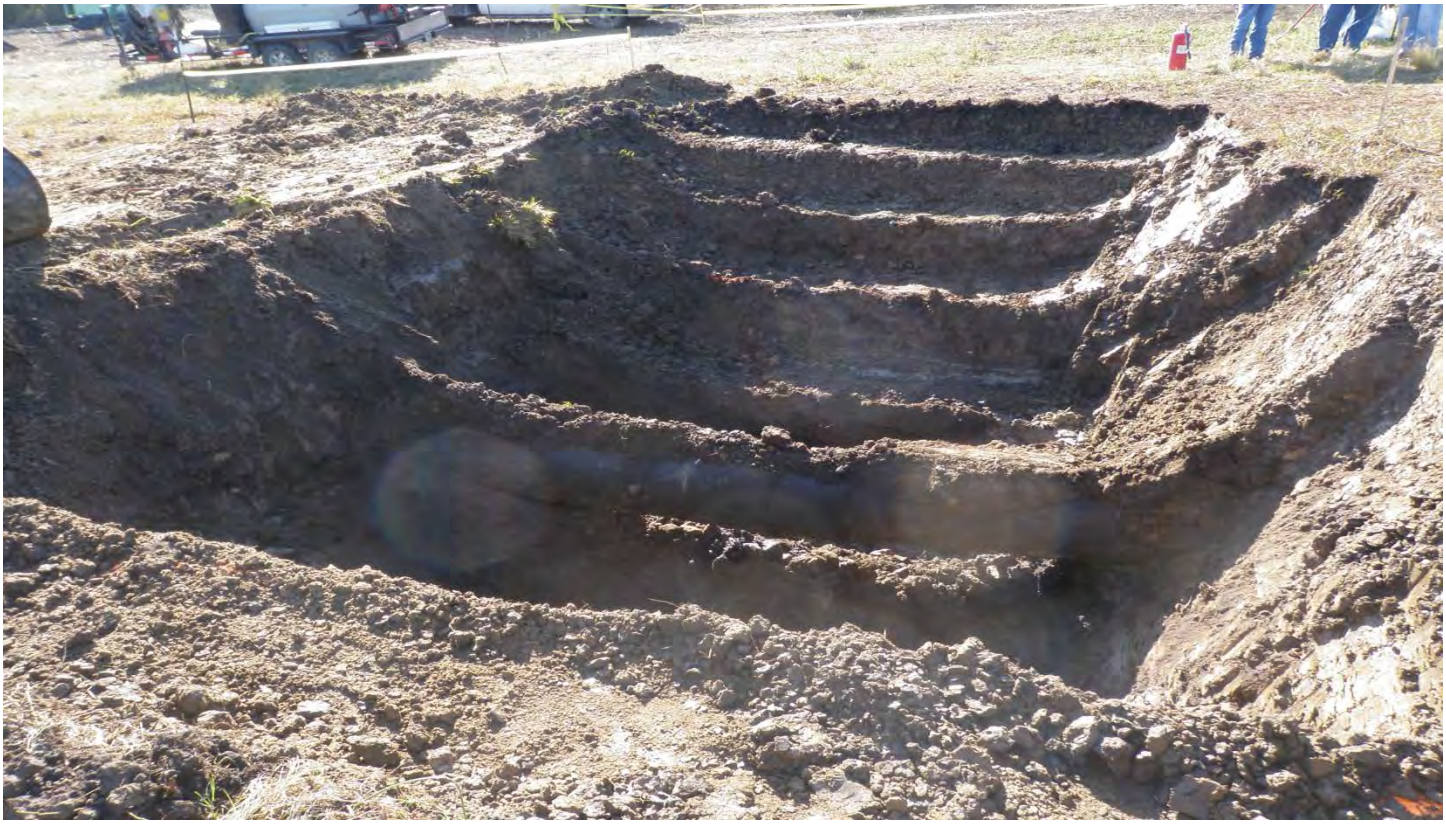
Shell Ho-Ho Pipeline Release Site near Vinton, LA 11-17-2011 11:38AM



Shell Ho-Ho Pipeline Deployment of OSRO Equipment 11-17-2011 11:38AM

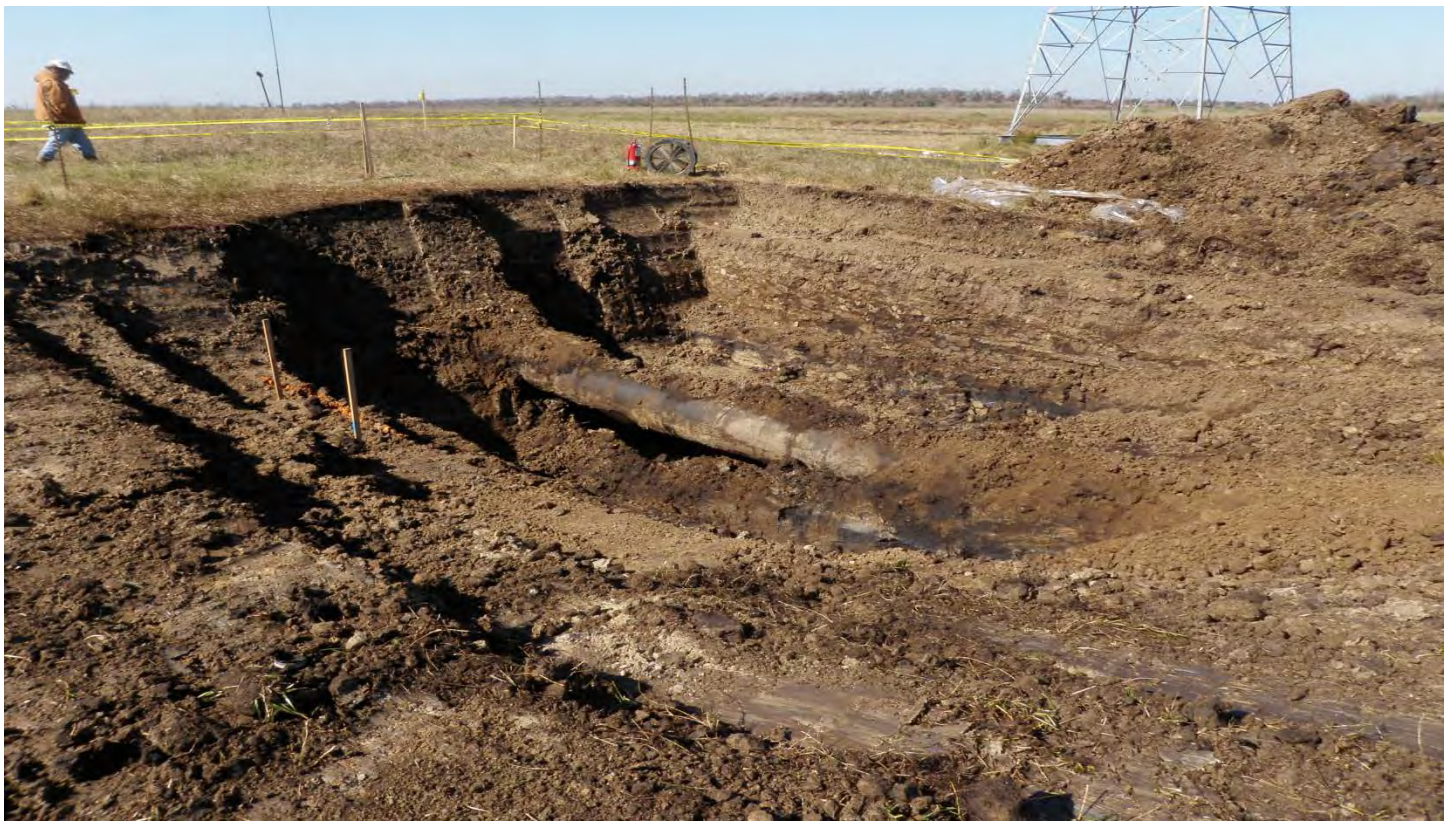


Shell Ho-Ho Pipeline Initial Excavation of Failure Site 11-18-2010 10:03AM



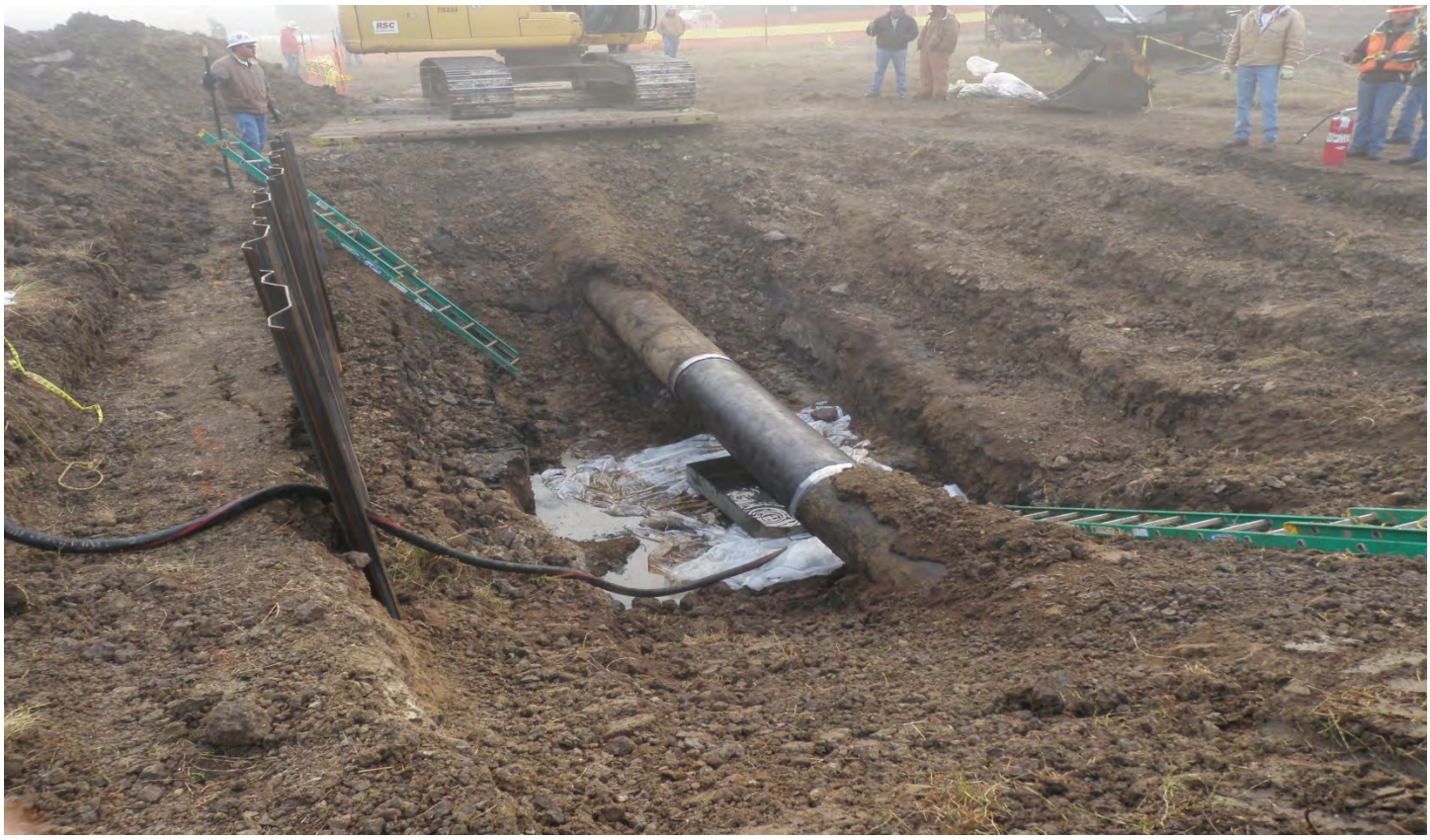
Shell Ho-Ho Pipeline Initial Excavation of Failure Site 11-18-2010 10:55AM

Shell Ho-Ho Pipeline Excavation of Failure Site 11-18-2010 1:27PM



Shell Ho-Ho Pipeline Excavation of Failure Site 11-18-2010 1:28PM

Shell Ho-Ho Pipeline Shoring for Repair of Pipeline 11-19-2010 8:2pAM

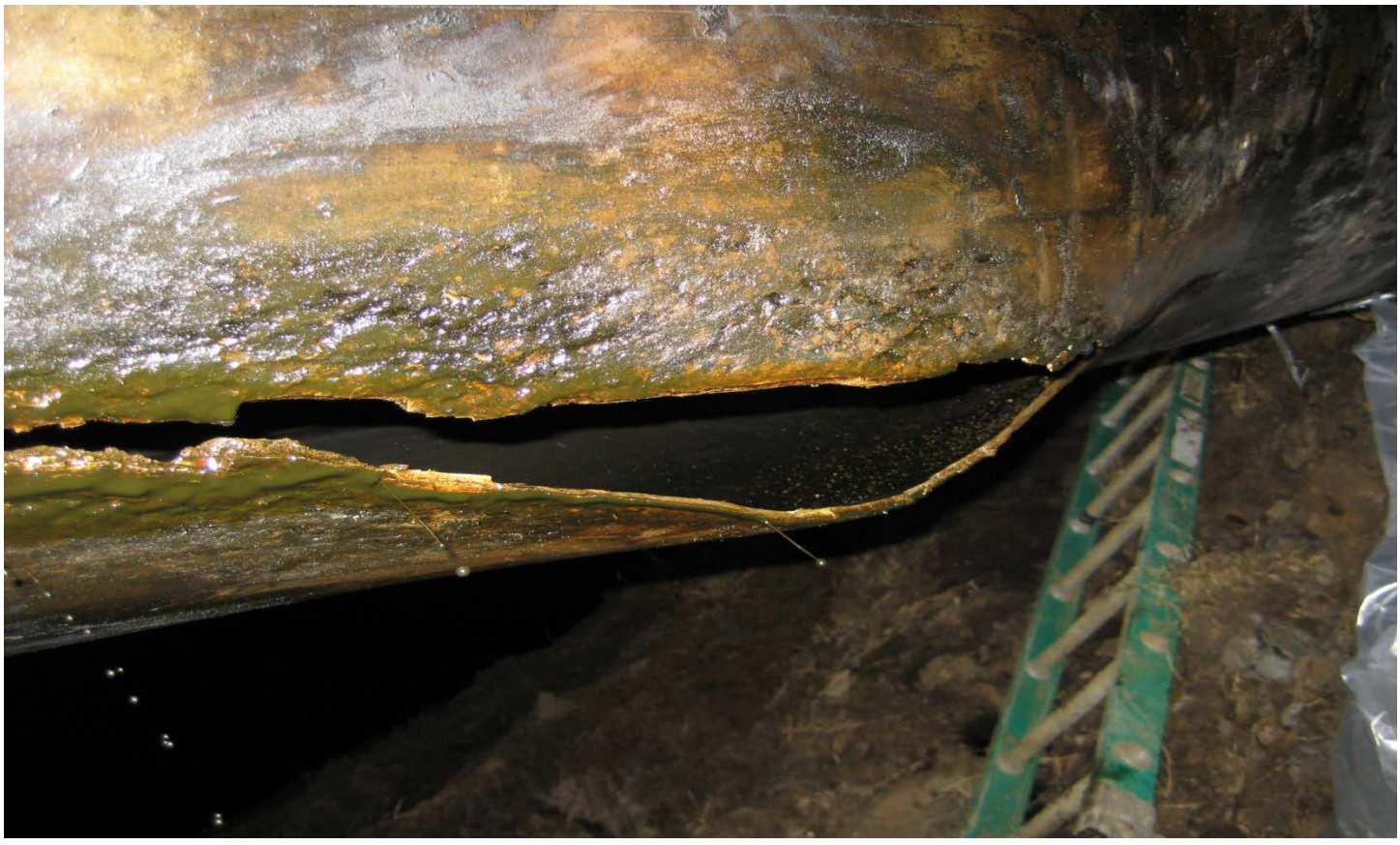


Shell Ho-Ho Pipeline Preparation of Segment for Cut-Out 11-19-2010 8:31AM

Shell Ho-Ho Pipeline Preparation of Segment for Cut-Out 11-19-2010 8:34AM

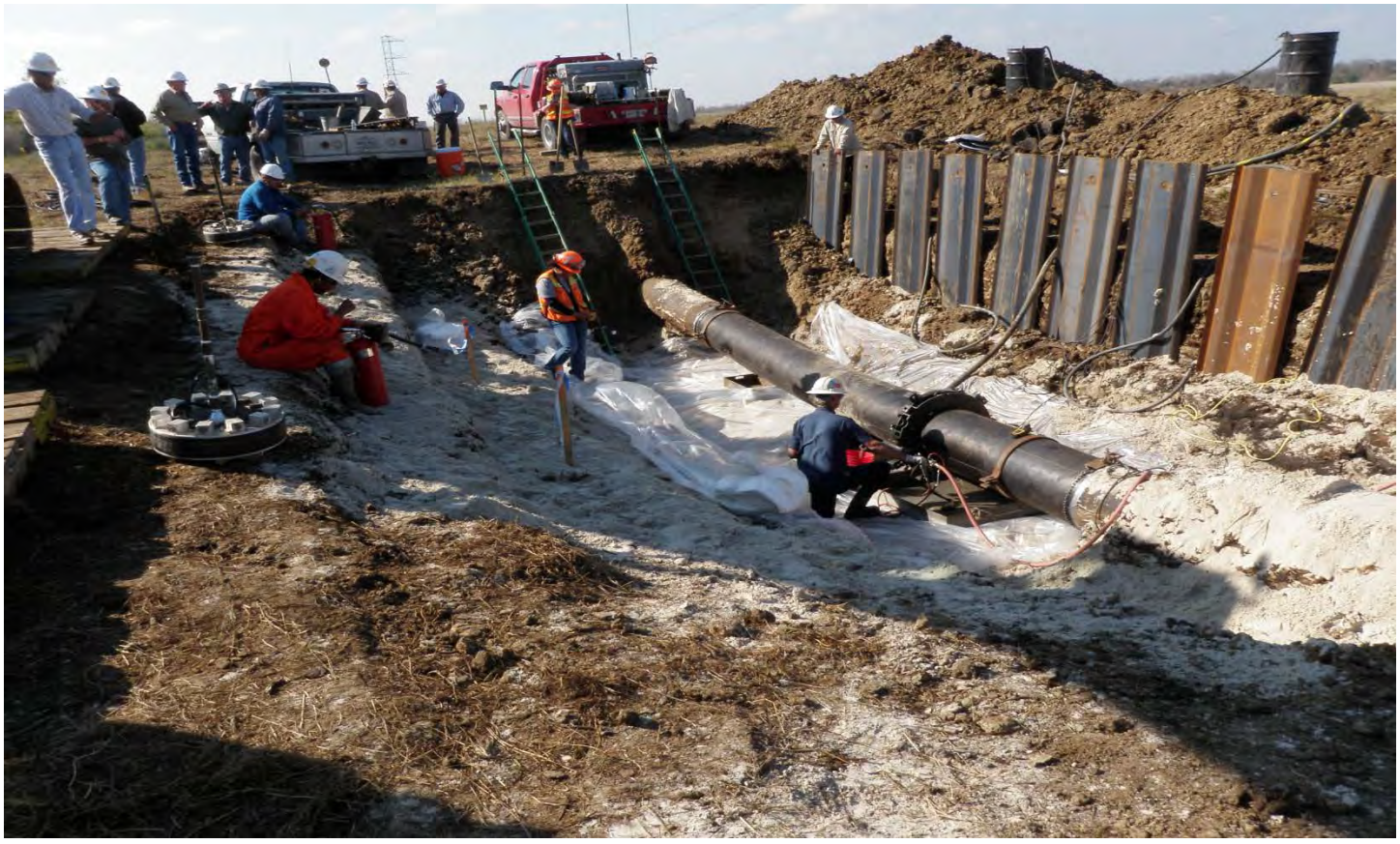
Shell Ho-Ho Pipeline Showing Coating on Pipeline 11-19-2010 11:43AM

Shell Ho-Ho Pipeline Failed Pipeline Segment 11-19-2010 2:20PM

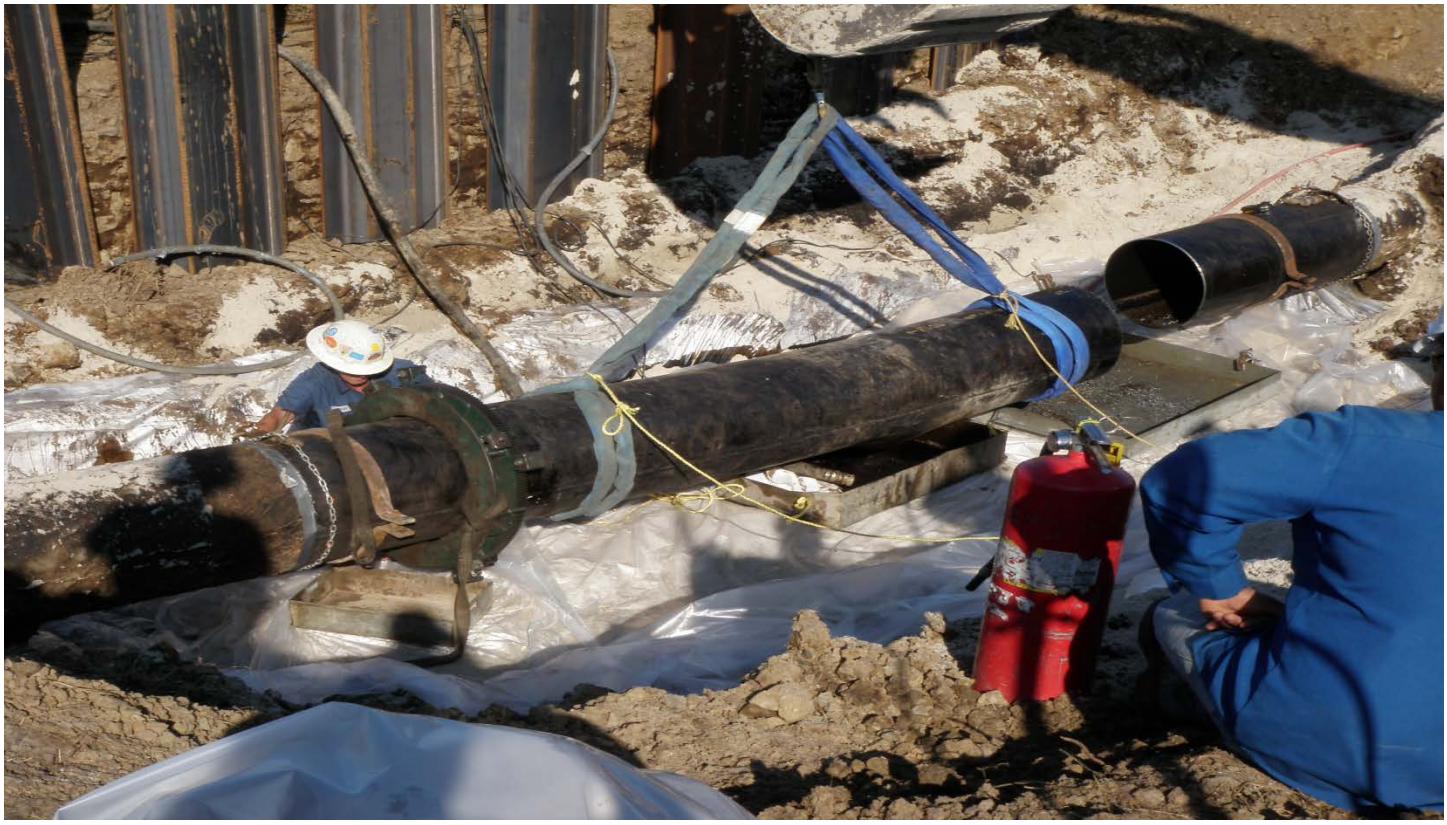


Shell Ho-Ho Pipeline Failed Pipeline Segment 11-19-2010 2:21PM

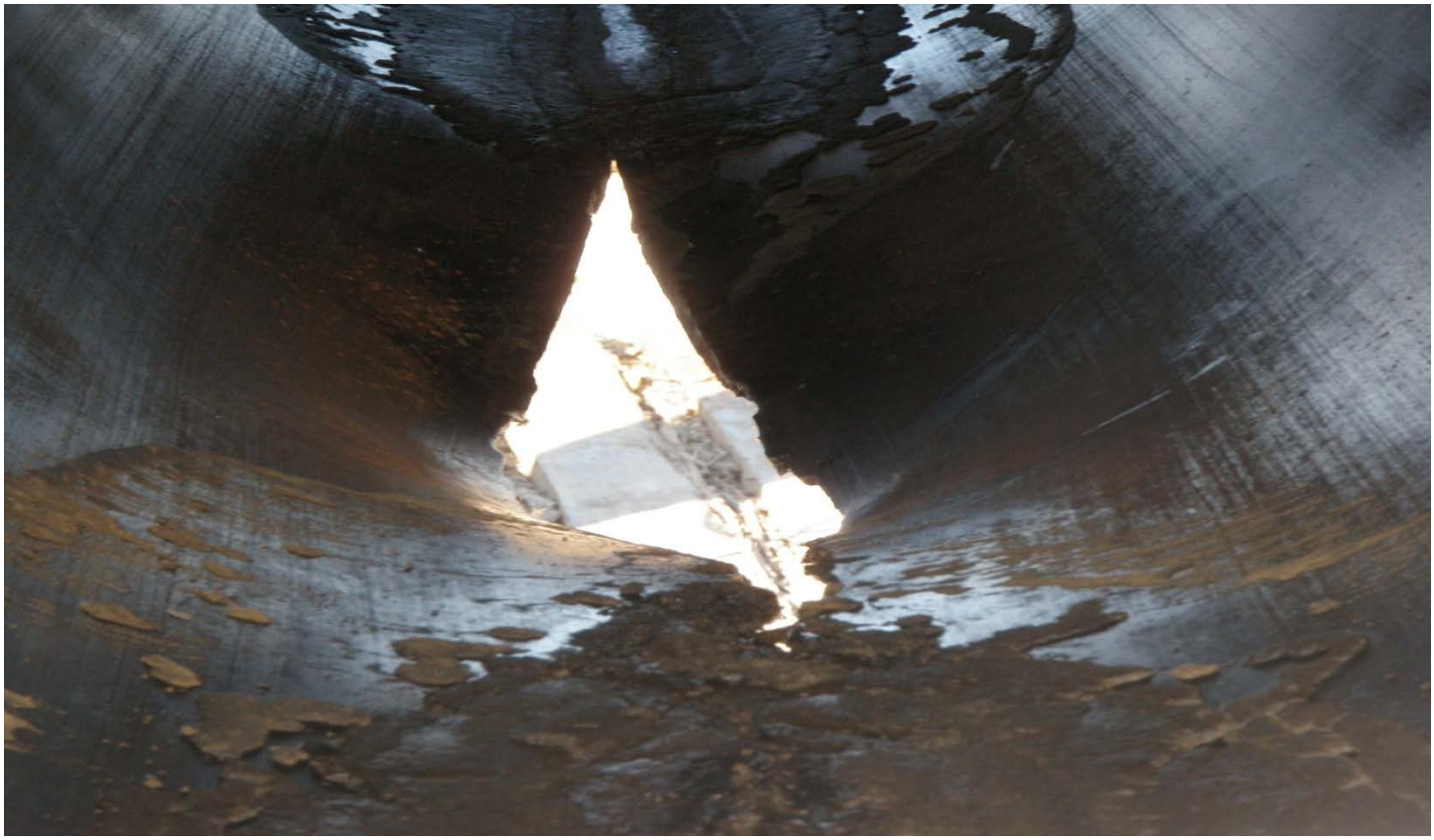
Shell Ho-Ho Pipeline Preparation of Segment for Cut-Out 11-20-2010 8:04AM



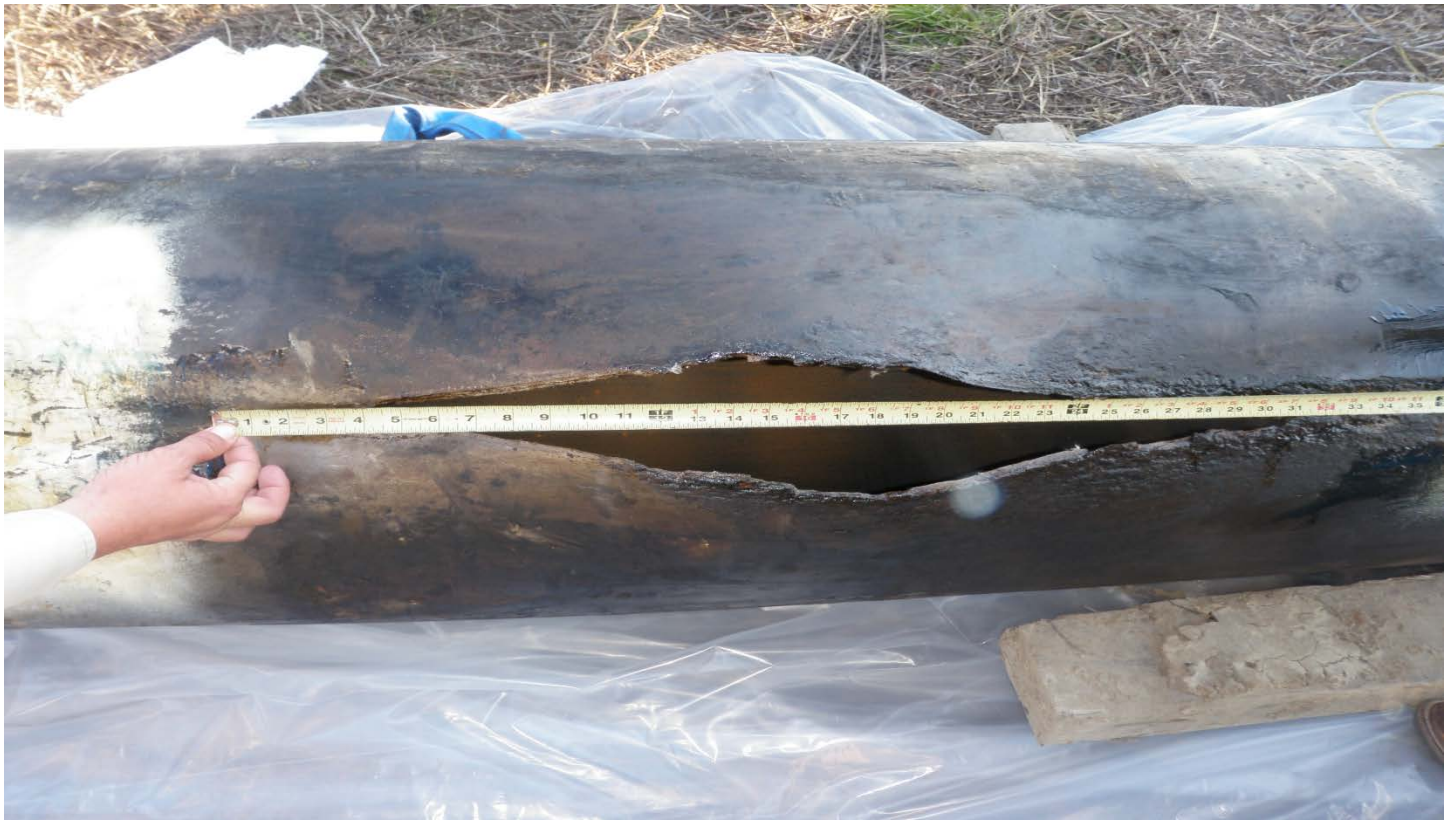
Shell Ho-Ho Pipeline Cold-Cutting Failed Segment 11-20-2010 2:44PM



Shell Ho-Ho Pipeline Cold-Cutting Failed Segment 11-20-2010 3:24PM

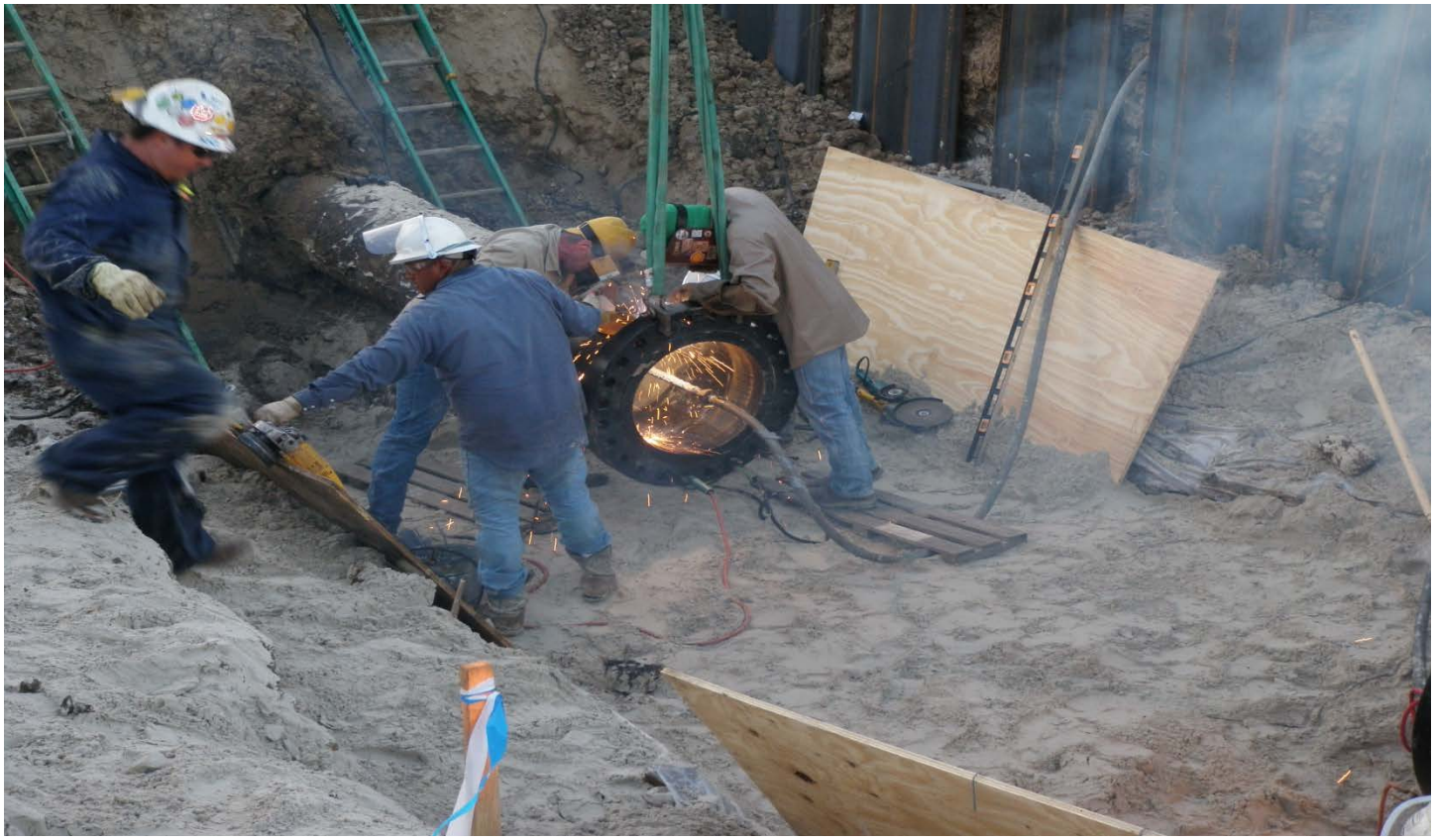


Shell Ho-Ho Pipeline Inside View of Failed Pipeline 11-20-2010 3:42PM



Shell Ho-Ho Pipeline Measurement of Ruptured Section 11-20-2010 3:49PM

Shell Ho-Ho Pipeline Preparing Pipe for Repair 11-20-2010 3:55PM



Shell Ho-Ho Pipeline Welding Flange for Spool-Type Repair 11-20-2010 5:51PM

Appendix A, B, C and G

These documents are on file at PHMSA