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

Principal Investigator	David Eng
Region Director	Rod Seeley
Date of Report	2/3/2014
Subject	Failure Investigation Report – Enterprise Crude Pipeline, LLC (Cushing West Tank Farm, Cushing, OK, Line C75)

Operator, Location, & Consequences

Date of Failure	4/8/2012
Commodity Released	Crude Oil
City/County & State	Cushing/Payne County, Oklahoma
OpID & Operator Name	30829 - Enterprise Crude Pipeline, LLC
Unit # & Unit Name	14464 – Oklahoma 30 Inch
SMART Activity #	139211
Milepost / Location	Breakout tank line C75 with Cushing West Terminal (Tank Farm) GPS Coordinates: 35.953247°N, 96.758858°W
Type of Failure	Breakout tank line failure due to internal corrosion
Fatalities	None
Injuries	None
Description of area impacted	The failure occurred within the operator's station facility located in a remote area
Property Damage	$1,698,327.00

Executive Summary

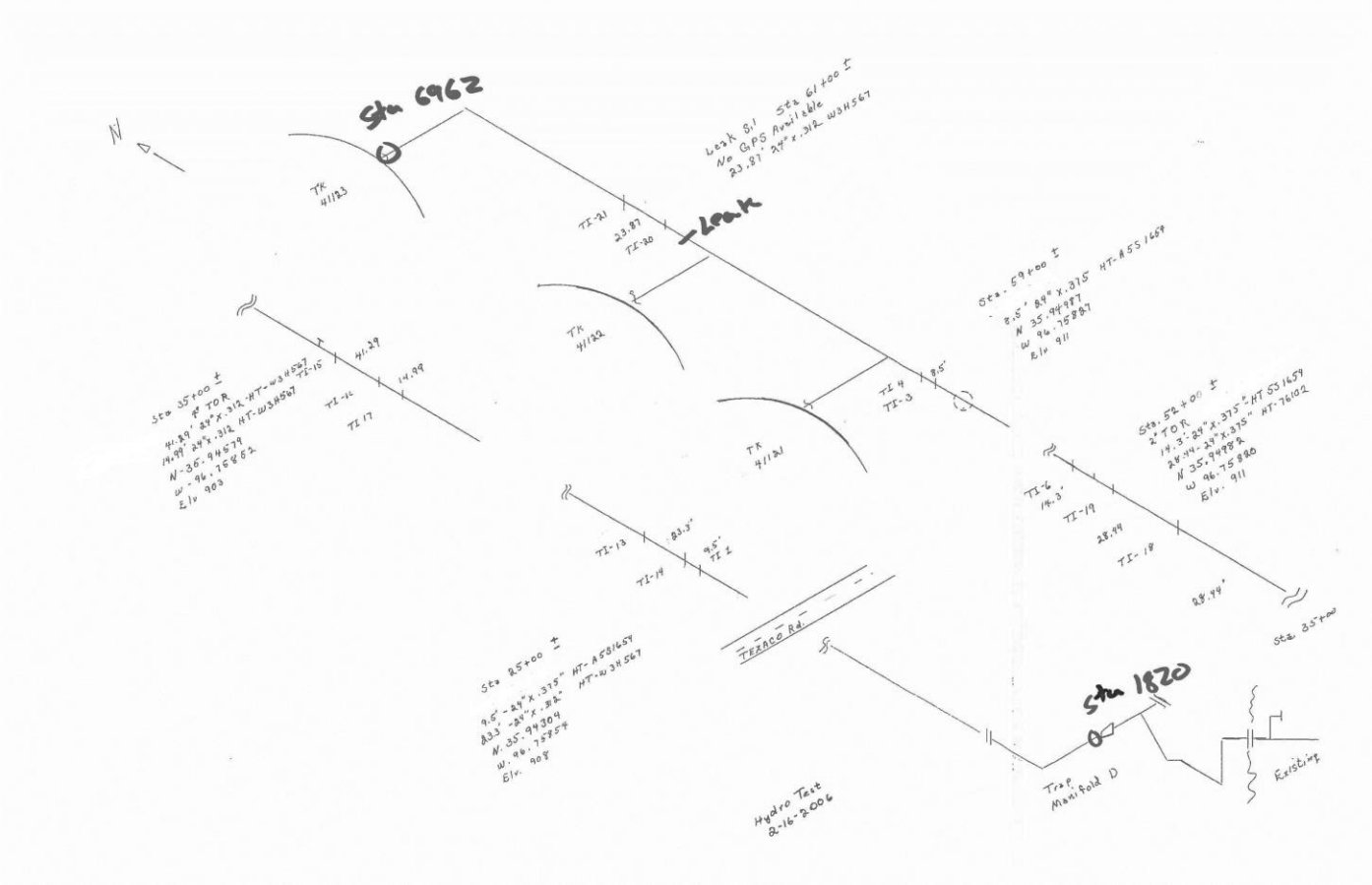
At approximately 10:04 p.m. central standard time (CST) on April 8, 2012, operations personnel for Enterprise Crude Pipeline, LLC (Enterprise) discovered a leak on their 24-inch C75 line located in their Cushing West Terminal Facility located in Cushing, Oklahoma. Enterprise reported the leak to the National Response Center (NRC 1008104) on April 8, 2012, at 10:46 p.m. CST. Upon detection of the release, Enterprise shut the line in. An accident investigator from the Pipeline and Hazardous Materials Safety Administration's (PHMSA) Southwest Region was dispatched to the failure site. A second PHMSA investigator coordinated with the control center for records.

Metallurgical analysis of the pipe concluded the root cause of the failure was internal corrosion. No other causal factors or controller/operator actions were determined to be involved with the incident.

The failure occurred completely within the facility's tank containment area. 600 barrels of oil were released and recovered on site. No fatalities or injuries were involved, and the overall cost associated with the accident was $1,698,327.00.

System Details

The failure occurred on Enterprise's C75 Line. Line C75 is located inside Enterprise's Cushing West Terminal in Payne County, Oklahoma, near the town of Cushing. The pipeline, 24-inches in nominal diameter, bi-directionally transfers crude oil between Manifold D to tankage within the Cushing West Terminal facility. There is no leak detection on the 24-inch line.



C75 Schematic Detail

Aerial View

The pipeline is included in the PHMSA-designated SMART Unit No. 14464 "OKLAHOMA 30 INCH." The system begins at the Texas-Oklahoma border near Colbert, OK, and terminates in Cushing, OK. The unit consists of approximately 152 miles of 30–inch-diameter pipeline with 10 tanks at Enterprise's Cushing East Terminal and 14 tanks (6 breakout) at their Cushing West Terminal. The unit includes header and interconnect piping to the Cushing East Terminal. Crude is shipped between the West and East Terminals for storage, utilizing tanks at both of these terminals. When Enterprise ships crude to Cushing, it is shipped via the 30-inch-diameter Seaway line.

Pipe Specifications

External markings for the line stated it was 24-inch outer diameter, 0.281–inch wall thickness, Grade X60, electric resistance welded (ERW) line pipe that was externally coated with fusion-bonded epoxy (FBE) coating at the pipe mill. The line was constructed in 1991-92 by Koch Pipeline Co. It was later sold to TEPPCO Partners LP before being acquired by Enterprise in 2007. Enterprise did not have any of the construction records for this line, indicating they were lost when Enterprise acquired the line. Therefore, no material test reports or hydrostatic test records were available for this portion of the unit at the time of the incident (hydrostatic record was subsequently provided by the operator). The operator stated that they were in the process of hydrotesting all the lines without records. Maximum operating pressures (MOP) were based on the lowest-rated appurtenances on the line, in this instance, ANSI 150 flange ratings in the terminal's piping. The MOP of the failed 24-inch-diameter line was 275 psi at the time of the incident. The normal operating pressure for the line is 70 psig.

Events Leading up to the Failure

Prior to the accident, on Saturday April 7, 2012, Plains Basin control was pumping crude oil through Enterprise's 24–inch-diameter C75 line through Manifolds A and D, which are under Enterprise's control. Neither company is capable of monitoring the other's operating status on the pumping or receiving end through their systems; they rely on verbal communication to confirm that the delivery process has started and/or stopped (there was no report of irregularities during the transfer process). The delivery was completed that same day. Enterprise did not discover the leak until Sunday night when crude oil was seen bubbling from the ground. It is not clear at this time whether the failure occurred during the pumping process or after when there was head pressure only on the line. There were no indications of any abnormal operations immediately prior to the discovery.

The pressure in the pipe at the time and location of the leak was 17 psig (the line normally operates at 70 psig). At peak operation, this section can see a flow rate of 17,000 barrels per hour of turbulent flow. No abnormal operations were observed or recorded during the previous day's transfer operations.

Emergency Response

At about 10:04 p.m. CST on April 8, 2012, Enterprise personnel observed oil within the containment dikes of Tanks 21 & 22 within their Cushing West facility. The operator began responding to the release and began shut in procedures shortly after discovery by closing off Manifold D (outside the West Cushing Terminal), Manifold A (inside the West Cushing Terminal), and the individual tanks within the terminal.

A review of station deliveries showed that the failed 24-inch-diameter line was not in service at time of discovery. Review of logs showed the last flow through the line had been at 8:00 p.m. CST the previous night (Saturday). This flow was a delivery to Tank 23, via the failed line, from the Plains Basin line through Enterprise's D and A manifolds in the West Cushing Terminal.

Additionally, operator personnel performed the following actions:

- Notified the National Response Center (NRC) at about 10:45 p.m. CST (Report No. 1008104);
- Executed their spill response plan, including summoning their Emergency Response Contractor;
- Began picking up free product; and
- Began the process of locating/excavating/exposing the leak source.

Enterprise reported a 600 barrel (approx. 25,000 gallons) release to the NRC with the cause of the leak as unknown at the time. Enterprise confirmed there were no injuries, explosions, or fires associated with this release. Enterprise also indicated that vacuum trucks were en route to pick up free product, and affected soil would be excavated.

Initial response to leak including additional precautionary berming

Emergency clean up contractors vacuuming up free product

Trenching and locating/exposing the leak source

Temporary clamp plug installed

As part of the emergency response, Enterprise's contractor performed a cut-out operation in the failure area to allow for visual field inspection of the interior surface of the line as well as in up and downstream directions. The cut-out was sent for metallurgical examination.

Cut out failure specimen and ship for metallurgical examination.

Summary of Initial Start-Up and Return-to-Service

During the accident response phase, discussions between PHMSA and the operator regarding returning the line to service prompted the operator to replace the entire 1500-foot section of 24–inch-diameter line rather than performing a welded "pup" type repair. Additionally, as part of the operator's corrective/preventative actions, improved hygienic maintenance capabilities were added to the system (launchers and traps for cleaning pigs) that were previously not in place.

Investigation Details

Control personnel were interviewed, and supervisory control and data acquisition (SCADA) and other flow records were reviewed, and no indications of abnormal operating conditions were observed or recorded on the system. No control room, SCADA, operational actions, operator qualification, or drug and alcohol issues were identified as contributory factors in this incident.

Initial field observations of the cut-out failure section indicated a 1.4-inch through wall hole had been created at the 6 o'clock position of the pipe at a low point in the line. The fusion-bonded epoxy coating on the exterior of the pipe immediately surrounding the hole was missing in a 1/4- to 3/4–inch-wide non-concentric border. Further observations from the field indicated the failure originated from an internal corrosion issue.

1 ¼" Leak

Other interior surfaces of the pipe (both in the cut-out sections and the remaining two cut ends) did not reveal similar deeply pitted corrosion surfaces as in the area immediately surrounding the hole. No other areas of obvious metal loss could be observed in the field.

All other areas of the fusion-bonded epoxy (FBE) coating appeared to be well-bonded and in good condition.

Metallurgical Analysis

After the failure specimen was cut out and removed, both ends were capped in plastic, and the remainder of the pipe was wrapped in clear plastic film for transport to Kiefner and Associates, Inc. (KAI) in Worthington, Ohio. A chain of custody was developed as part of transporting the specimen.

The investigation of the cut-out at KAI consisted of a visual inspection of the specimen, metallographic examination through the leak path section, and the bacteria testing of foreign material found in the leak path. Additionally, the sizes, steel compositions, and tensile properties of the pipe material were measured.

Visual Inspection

Upon arrival at KAI, the failure specimen was unwrapped and photographed. The specimen had not been marked with clock positions, but Enterprise noted to the lab the leak hole was at the 6 o'clock position. The diameter of the hole was measured at 1.4-inches with a circular area around the hole missing the FBE coating.

The external area with missing coating and exposed metal was corroded. The laboratory report summarized this in the following:

> *"The missing coating and corroded metal on the external surface can be rationalized as follows. Initially, the internal corrosion pit perforated the pipe wall as a pinhole without breaking the FBE coating. Then corrodants from the pit migrated between the coating and external pipe wall, causing the latter to corrode under the coating until internal pressure in the pipeline ruptured the circular area of coating."*

The FBE on the remaining portions of the specimen appeared in good condition, as had been previously observed in the field. The internal surface was covered with oil. Aside from the area with the hole, no other areas of metal loss were evident on the specimen.

So that the internal surface could be more easily examined, an 11-inch by 14-inch coupon surrounding the hole was cut from the failure specimen. The coupon's internal wall surface was covered in orange rust with the pit wall surface caked in oil. The coupon's interior wall surface and pit interior were cleaned to remove the oil and rust. As noted in KAI's metallurgical report, *"the bare metal wall of the pit was covered with smaller pits. The pit within pits morphology is consistent with the pit having formed under an occlusion, such as a biofilm or a deposit."*

Metallography

Metallography was performed on a transverse cross section through the longitudinal seam weld that was cut out, polished, and etched. This verified the longitudinal seam weld was a high-frequency, electric-resistance weld (HF-ERW) that was subjected to a localized, post-weld heat treatment. The heat treatment eliminated hard microstructures in the heat-affected zone of the ERW seam weld as required by the 40th Edition of API 5L. The manufacture of the long seam weld by the pipe mill showed no contributory factors to the failure.

A metallographic-sectioned specimen was prepared through the pit opening and polished for examination. Micrographs showed the mouth of the pit on the internal surface of the pipe to be wider than the external surface. This indicated the pit initiated on the internal surface of the pipe and grew outward toward the exterior of the pipe.

The microstructure of the steel adjacent to the pit was no different than the microstructure of the steel in the remaining cross section, which was of a fine-grained ferrite structure. There were also no visible metallurgical defects associated with the pit. Nothing in the microstructure's characteristics could be observed as contributory to the failure.

Tests for Bacteria (MIC related)

The pit wall was tested for the presence of five types of bacteria that can accelerate the corrosion of steel. As a comparison, an area of the internal wall was also tested where corrosion was not observed.

Tests that microbiologically influenced corrosion (MIC) created the pit were inconclusive. Though the pit wall contained some viable anaerobic bacteria and some viable low-nutrient bacteria, it did not contain detectable numbers of viable sulfate-reducing, acid-producing, or iron-related bacteria. Correspondingly, the non-corroded area on the internal pipe wall yielded results similar to that of the corroded portion.

The internal pipe surface around the hole revealed it was the result of an internal corrosion pit that had grown through the pipe wall. The pit wall was covered with smaller pits. This indicated the pit grew under an occlusion such as a deposit or a biofilm. As corrosion-related bacteria were detected, there is a possibility that these bacteria entered the pipe after the pit formed.

The presence of MIC bacteria, itself, is inconclusive as to the cause. The bacteria found in the test could have entered the pipe when the line was unpressurized or when the failed section was cut out in the ditch. Therefore, the test results for MIC could not adequately determine if MIC was a causal factor.

Physical Properties of the Pipe Specimen

A series of tests to confirm the size, steel composition, and tensile properties of the pipe were performed by KAI. These results were compared to requirements in the 40th Edition of API Specification 5L - November 1, 1992 (the edition of 5L in effect when the line was constructed).

Testing concluded the pipe material met the size, chemical, and tensile properties for API 5L, Grade X65 line pipe for the era of construction as well as the standard of manufacture and construction. Based on the findings of these tests, neither the pipe material nor the line's construction method contributed to the failure.

Findings and Contributing Factors

Determining the cause of the failure relied on visual observations of the failed section when exposed in the field, review of operational records, interviews with operator personnel, and the results of the metallurgical testing.

When the failure point was observed in the ditch (prior to cut-out) by the PHMSA inspector, it was clear that the hole had formed at the 6 o'clock position on the lowest point of that portion of the line. This low point was further confirmed when the cut-out was removed and both cut ends continued to drain their respective portions of remaining product.

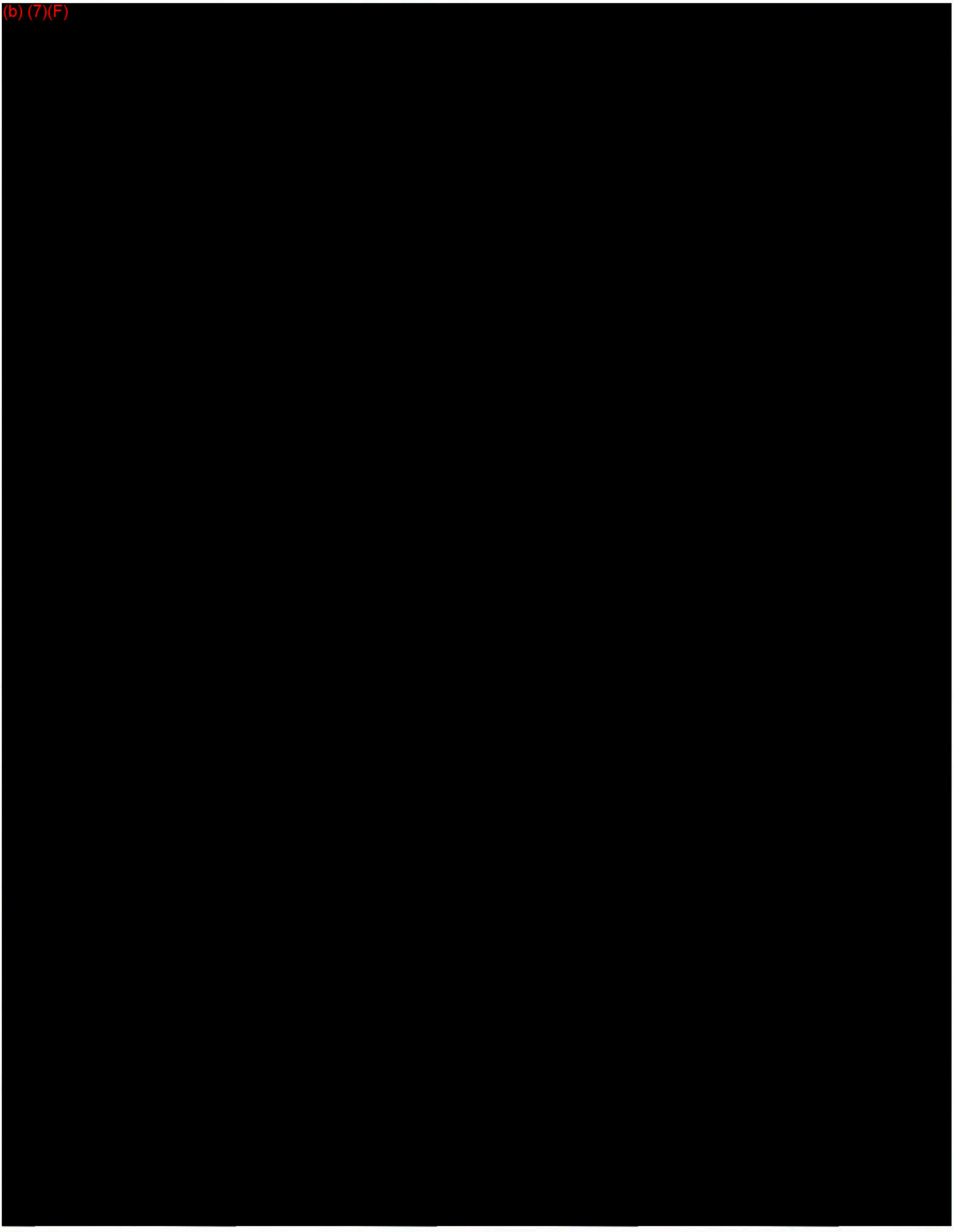
Interviews with station operations personnel revealed that while the line did see turbulent flow when in use (up to 17,000 barrels per hour), it did not receive any cleaning pig operations (unpiggable at time of failure) or other activities to ensure the hygiene of these lines against internal corrosion.

Ultimately, the cause of the failure was a result of internal corrosion. When determining the cause of the failure, discussions between PHMSA and the operator prompted a full line replacement within the station from the supply manifold to the tankage, rather than repairing the failed section with a pup. This line replacement included upgrading this portion of the line to allow maintenance pigging activities as a preventative measure against a similar type failure in the future.

Appendices

A Maps
B NRC Report (1008104)
C Accident Report 7000.1 (20120141)
D Hydrotest Records
E Metallurgical Report

(b) (7)(F)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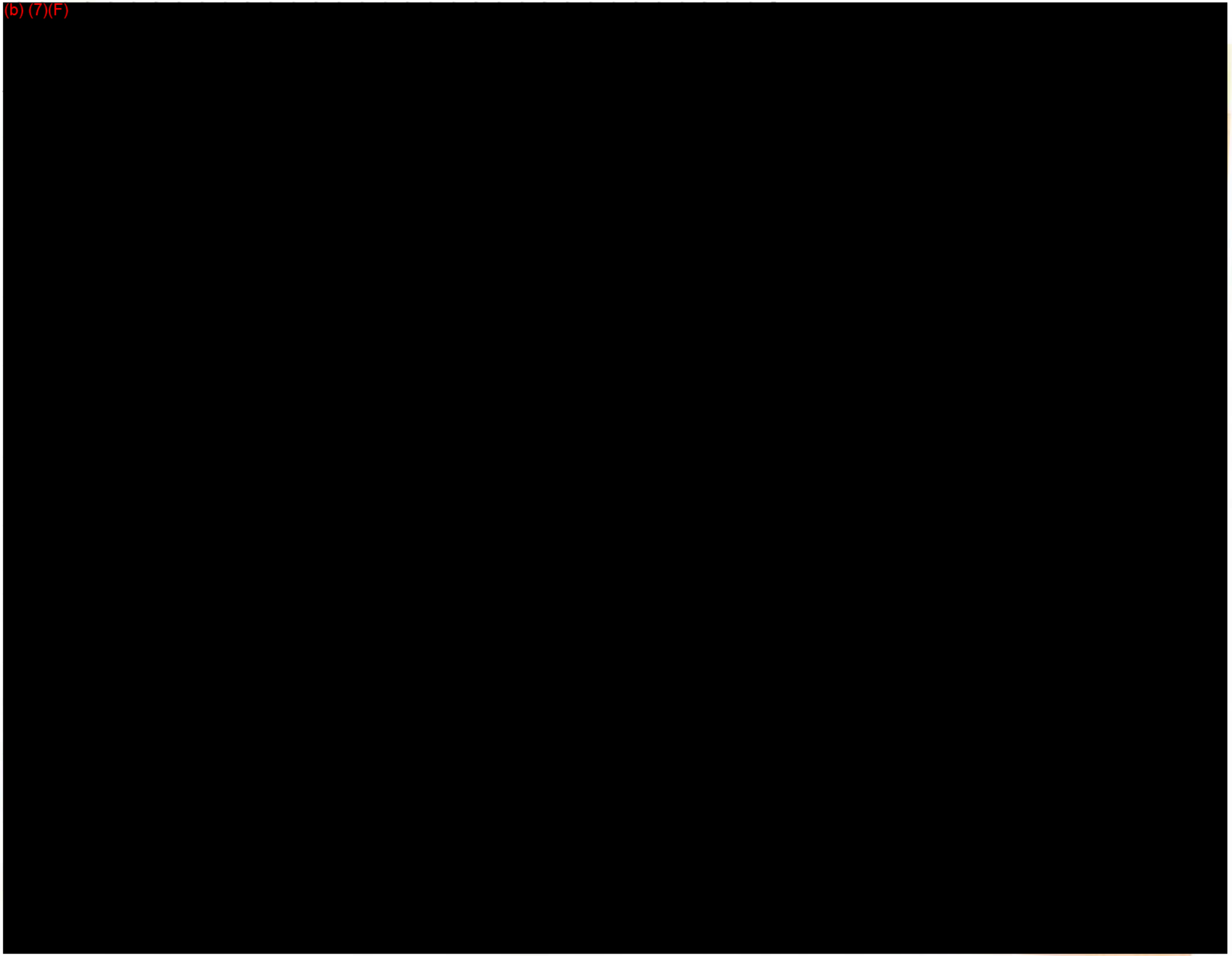
(b) (7)(F)

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

Incident Report # 1008104

INCIDENT DESCRIPTION

*Report taken at 23:46 on 08-APR-12
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
The incident was discovered on 08-APR-12 at 21:30 local time.
Affected Medium: SOIL / SECONDARY CONTAINMENT

SUSPECTED RESPONSIBLE PARTY

Organization: ENTERPRISE PRODUCTS PIPELINE
HOUSTON, TX 77064

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

908 E. ESECO ROAD County: PAYNE
City: CUSHING State: OK

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 600 BARREL(S)

DESCRIPTION OF INCIDENT

CALLER IS REPORTING A DISCHARGE OF CRUDE OIL FROM A 24" UNDERGROUND LINE DUE TO UNKNOWN CAUSES.

INCIDENT DETAILS

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

DAMAGES

Fire Involved: NO Fire Extinguished: UNKNOWN

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

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

Passengers Transferred: NO

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

REMEDIAL ACTIONS

STATION PIPING IS ISOLATED, VAC TRUCK IS EN ROUTE TO PICK UP THE FREE OIL, AREA WILL BE EXCAVATED.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: PARTLY CLOUDY, °F

ADDITIONAL AGENCIES NOTIFIED

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

NOTIFICATIONS BY NRC

USCG ICC (ICC ONI)
08-APR-12 23:53
CGIS RAO ST. LOUIS (COMMAND CENTER)
08-APR-12 23:53
COLORADO INFO ANALYSIS CENTER (FUSION CENTER)
08-APR-12 23:53
DHS PROTECTIVE SECURITY ADVISOR (PSA DESK)
08-APR-12 23:53
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
08-APR-12 23:53
U.S. EPA VI (MAIN OFFICE)
08-APR-12 23:55
GULF STRIKE TEAM (MAIN OFFICE)
08-APR-12 23:53
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
08-APR-12 23:53
NOAA RPTS FOR OK (MAIN OFFICE)
08-APR-12 23:53
NTSB PIPELINE (MAIN OFFICE)
08-APR-12 23:53
OFC OF ENV SVC CHEROKEE NATIONS OK (MAIN OFFICE)
08-APR-12 23:53
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
08-APR-12 23:53
SAC AND FOX NATION (EMERGENCY MANAGEMENT)
08-APR-12 23:53
DEQ OKLAHOMA (MAIN OFFICE)
08-APR-12 23:53
USCG DISTRICT 8 (MAIN OFFICE)
08-APR-12 23:53

ADDITIONAL INFORMATION

NO ADDITIONAL INFORMATION.

*** END INCIDENT REPORT # 1008104 ***

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0047 EXPIRATION DATE: 01/31/2014
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	05/09/2012
	No.	20120141 - 18685 (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

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:	10/31/2013		
1. Operator's OPS-issued Operator Identification Number (OPID):	30829		
2. Name of Operator	ENTERPRISE CRUDE PIPELINE LLC		
3. Address of Operator:			
3a. Street Address	1100 Louisiana Street		
3b. City	Houston		
3c. State	Texas		
3d. Zip Code	77002		
4. Local time *(24-hr clock)* and date of the Accident:	04/08/2012 22:04		
5. Location of Accident:			
Latitude:	35.953247		
Longitude:	-96.758858		
6. National Response Center Report Number (if applicable):	1008104		
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	04/08/2012 22:46		
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):	600.00		
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):			
11. Estimated volume of commodity recovered (Barrels):	600.00		
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:	04/08/2012 22:04
14b. Local time pipeline/facility restarted:	06/22/2012 15:00
- 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:	04/08/2012 22:04
18b. Local time Operator resources arrived on site:	04/08/2012 22:04

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:	Oklahoma
3. Zip Code:	74023
4. City	Cushing
5. County or Parish	Payne
6. Operator-designated location:	
Specify:	
7. Pipeline/Facility name:	C75
8. Segment name/ID:	Cushing West Terminal
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Totally contained on Operator-controlled property
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	36
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 Terminal/Tank Farm Equipment and Piping
- 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):	24
3b. Wall thickness (in):	.281
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	65,000
3d. Pipe specification:	API 5L
3e. Pipe Seam , specify:	Longitudinal ERW - High Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	Unknown
3g. Year of manufacture:	1991
3h. Pipeline coating type at point of Accident, specify:	Fusion Bonded Epoxy
- 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:	
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Leak
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	Pinhole
- If Other, Describe:	Size of a dime
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- 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	
- 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?	No
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	$ 0
8b. Estimated cost of commodity lost	$ 60,000
8c. Estimated cost of Operator's property damage & repairs	$ 1,560,277
8d. Estimated cost of Operator's emergency response	$ 63,100
8e. Estimated cost of Operator's environmental remediation	$ 14,950
8f. Estimated other costs	$ 0
Describe:	
8g. Total estimated property damage (sum of above)	$ 1,698,327

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	20.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	275.00
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?	No
- If Yes - *(Complete 5a. – 5e. 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)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	
- 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?	No
If Yes -	
6a. Was it operating at the time of the Accident?	
6b. Was it fully functional at the time of the Accident?	
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
- If Yes:	
7a. Was it operating at the time of the Accident?	
7b. Was it fully functional at the time of the Accident?	
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	
8. How was the Accident initially identified for the Operator?	Local Operating Personnel, including contractors
- 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:	Operator employee
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)*	It was obvious that operator was not at fault. Pipe was under atmospheric pressure at the time of the incident.
- 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:	
Internal Corrosion:	Yes
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
□4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	Localized Pitting
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	Yes
- Microbiological	Yes
- 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	Yes
- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	Yes
- Elbow	
- Other:	

- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	No
11. Was the interior coated or lined with protective coating?	No
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	No
13. Were corrosion coupons routinely utilized?	No
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?	No
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	Yes
If Yes -	
Most recent year tested:	2006
Test pressure:	364.00
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

The station operator observed oil in the dike of tanks 21 and 22. The lines were isolated and free standing oil was removed prior to excavation. Line was hydrovaced and clamped the following morning.
Existing 1500 feet of 24 inch pipe from Manifold A to Tank #23 was removed, replaced and back into service with new 24 inch pipe on June 22, 2012.

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PART I - PREPARER AND AUTHORIZED SIGNATURE

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Appendix D

Hydrotest Records

This document is on file at PHMSA

Appendix E

Metallurgical Report

This document is on file at PHMSA