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

Principal Investigator	Molly Atkins
Region Director	R.M. Seeley
Date of Report	6/10/2016
Subject	Failure Investigation Report – Texas Gas Transmission, LLC, Gas Pipeline Rupture in Farmerville, LA

Operator, Location, & Consequences

Date of Failure	September 9, 2015
Commodity Released	Natural Gas – 42,100.00 MCF
City/Parish & State	Farmerville, Union Parish, Louisiana
OpID & Operator Name	19270, Texas Gas Transmission, LLC
Unit # & Unit Name	3964, Sharon-Haughton Area
Inspection System ID	3020
SMART Activity #	151281
Milepost/Location	MLS 26-1, Mile Post (MP) 28.8
Fatalities	0
Injuries	0
Evacuations	General public – 16 people in the surrounding area
Description of Area Impacted	Pipeline right-of-way in a rural area
Property Damage	$220,000 of estimated property damage and $248,000 of gas loss. Total cost: $468,000.

Executive Summary

On September 9, 2015, at approximately 4:33 p.m. Central Time (CT), a pipeline rupture occurred on Texas Gas Transmission, LLC's (TGT), No. 1 line (MLS 26-1). MLS 26-1 is a 26-inch-diameter pipeline that is part of TGT's main line natural gas pipeline system located near mile post (MP) 28.8 in Farmerville, Union Parish, Louisiana. The rupture ejected a piece of pipe 45 feet and 10 inches long from the ditch into a wooded area adjacent to the pipeline right-of-way (ROW). This pipeline failure did not result in ignition of the escaping gas, injuries, or fatalities; however, 16 people were evacuated from the surrounding area overnight as a precautionary measure.

At 5:23 p.m. CT the TGT reported the incident to the Pipeline and Hazardous Materials Safety Administration (PHMSA) in National Response Center (NRC) report #1128025. PHMSA dispatched an investigator to perform an on-site investigation.

Metallurgical failure analyses determined that the cause of the accident was a combination of corrosion and near-neutral pH stress corrosion cracking at a point located on the bottom of the pipeline where the pipe was installed over an area of sandy clay and rocky material.

System Details

The TGT is a long-haul interstate natural gas pipeline that transports gas from Gulf Coast supply areas to on-system markets in the Midwest and off-system markets in the Northeast. The TGT is a wholly owned operating subsidiary of Boardwalk Pipeline Partners, LP (BWP).[1]

BWP is a midstream master limited partnership that provides transportation, storage, gathering, and processing of natural gas and liquids. It owns and operates approximately 14,090 miles of interconnected natural gas pipelines through its subsidiaries, directly serving customers in 13 States and indirectly serving customers throughout the Northeastern and Southeastern United States via numerous interconnections with unaffiliated pipelines. BWP also owns and operates more than 435 miles of natural gas liquid pipelines in Louisiana and Texas. The BWP system is represented by the map shown in Figure 1:

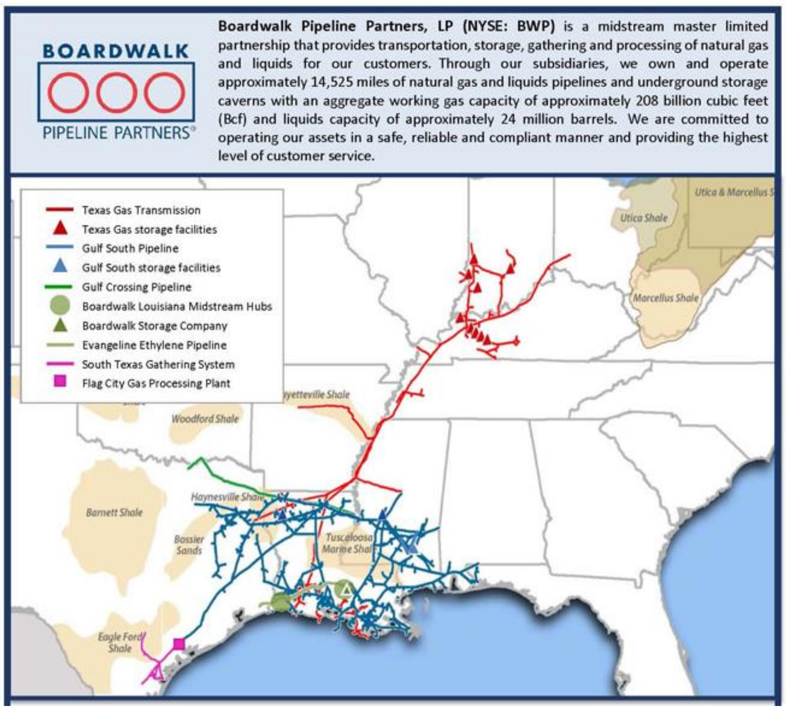

Figure 1 – Boardwalk Partners Pipeline, LP, System Map[2]

The TGT runs north and east from Louisiana, eastern Texas, and Arkansas through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky, and Indiana; it also travels into Ohio and, via smaller-diameter lines, Illinois. The market area directly served by the TGT encompasses eight States in the South and Midwest, including the following metropolitan areas: Memphis, Tennessee; Louisville, Kentucky; Cincinnati and Dayton, Ohio; and Evansville and Indianapolis, Indiana. The TGT also has indirect market access to the Northeast through interconnections with unaffiliated pipelines.[2]

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[1] Texas Gas Transmission, LLC. *Welcome to Texas Gas*. Retrieved from: http://www.txgt.com/.
[2] Boardwalk Pipeline Partners. *Fact Sheet.* Retrieved from: http://www.bwpmlp.com/AboutUs.aspx?id=146.

The incident occurred on the TGT's MLS 26-1 at approximately MP 28.8. Figure 2 is a post-incident view of the general vicinity and the ROW, which is in Union Parish in rural north-central Louisiana. Additional photographs of the vicinity may be found in the metallurgical failure analysis in Appendix A.

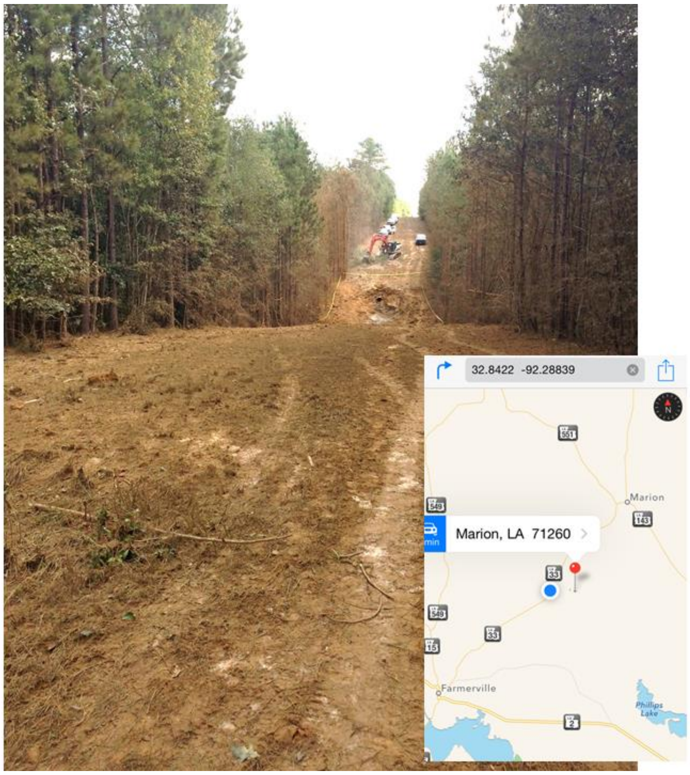


Figure 2 - Incident Vicinity Map and ROW Looking to the East

This pipeline system (ISID 3020) is in the PHMSA-identified Sharon-Haughton Area (Unit ID 3964), which is inspected by PHMSA's Southern Region.

Pipe Specifications

The pipeline was constructed in 1949 using American Petroleum Institute (API) 5LX Grade X52 electric fusion-welded pipe manufactured by the A.O. Smith Corporation. The pipe is 26 inches in outside diameter with a nominal wall thickness of 0.281 inches at the failure location. The maximum allowable operating pressure (MAOP) of the pipeline, as established by hydrostatic testing, is 810 pounds per square inch gauge (psig). The most recent test took place on September 23, 1976, and included a 100% specified minimum yield strength (SMYS) spike test followed by a 90% SMYS eight-hour hold period without any failures. The pipeline was originally covered with a coal tar-type coating and protected from external corrosion via an impressed current cathodic protection (CP) system that was put into service in 1949.

Events Leading up to the Failure

The TGT was operating the pipeline at 766 psig immediately prior to the incident. The pipeline was flowing at a lower pressure than normal due to maintenance activities that were being conducted in the area at the time of the failure.

Emergency Response

The operator received a call from local emergency responders reporting an explosion and blowing gas in the vicinity of the pipeline ROW at approximately the same time as the pipeline control center observed a pressure drop on the supervisory control and data acquisition system. The TGT initiated its emergency response procedures, isolated a 10-mile pipeline segment between the upstream and downstream valves on either side of the failure location, and evacuated 16 people from the surrounding area as a precautionary measure. The TGT notified the NRC of the accident at 5:23 p.m. CT in NRC Report #1128025, which PHMSA's

Southwest Region received via email from the Crisis Management Center at 5:43 p.m. CT. PHMSA dispatched a Southwest Region accident investigator to the site at 6:00 p.m. CT.

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

The damaged area of the line was replaced with a new segment of pipe, at which time a pig launcher and receivers were added to allow the TGT to perform in-line inspection (ILI) on the pipeline segment. Due to the mode of failure, and based on the results of the root cause analysis, the TGT determined that they needed to perform an ILI inspection using both magnetic flux leakage (MFL) and transverse flux inspection (TFI) tools prior to restarting the system. The TGT purged the pipeline and maintained a maximum operating pressure of 648 psig—80% of the 810 pounds per square inch MAOP—while they performed the internal inspection. The TGT operated the pipeline at the reduced pressure of 648 psig until after ILI data was received and actionable anomalies were addressed. The pipeline was returned to full operating pressure on December 18, 2015.

The TGT used deformation tool inspection and the data from the MFL to identify signatures similar to the anomaly that caused the pipeline failure. Of the 14 locations identified and excavated—all of which had potential matching attributes and indications—none displayed stress corrosion cracking (SCC).

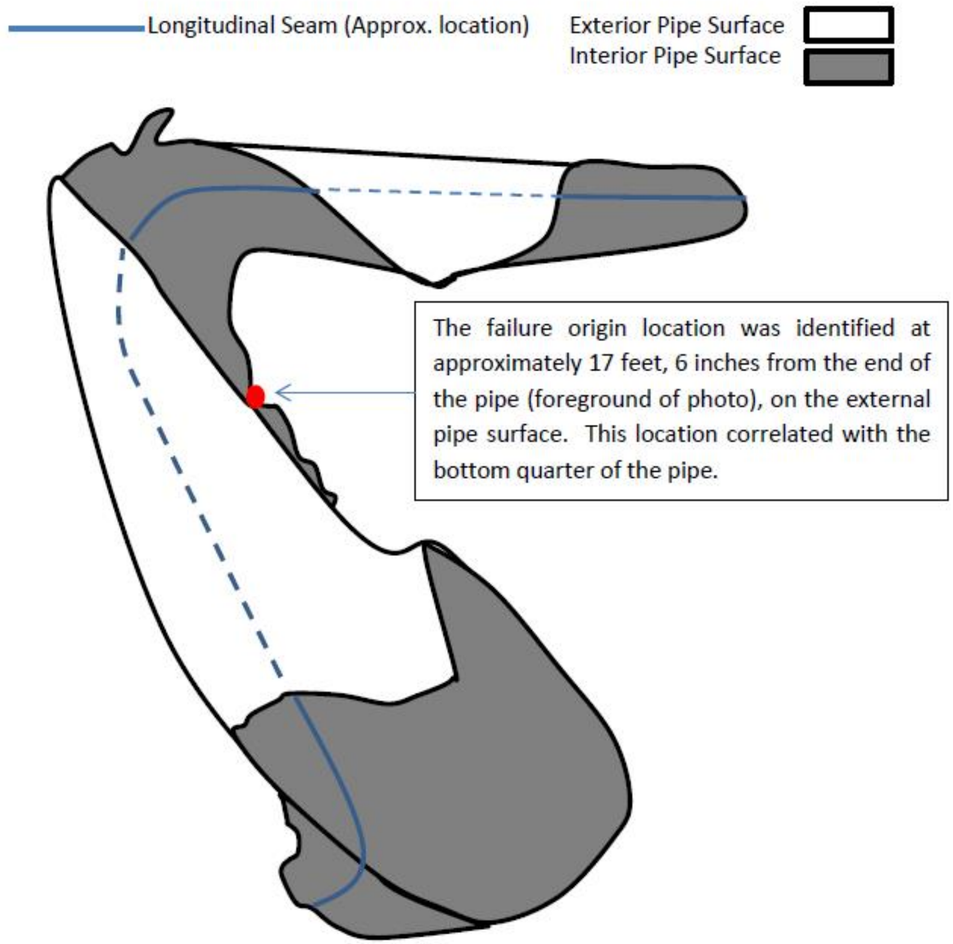
Investigation Details

At 7:30 a.m. CT on September 10, 2015, the PHMSA Southwest Region accident investigator arrived at the failure site, which he toured after meeting operator personnel. At approximately 12:00 p.m. CT a staff consultant/metallurgist from Stress Engineering Services, Inc. (SES), arrived onsite to begin evidence collection and to perform a site survey. PHMSA accompanied the SES metallurgist during the site survey to monitor field measurements and observations.

The origin of failure was identified on the bottom quarter of the segment of pipe that was ejected from the ditch, as depicted in a diagram sketched by PHMSA and shown in Figure 3:

Figure 3 - Failure Origin Location Sketch by PHMSA

Pipe ejected from the ditch and rotated 180 degrees such that the east end of the pipe as found in the woods was the failure surface that matched the west end of the rupture site. The approximate total length of the ejected pipe segment was 45 feet, 10 inches.



Measurements were taken after the origin of failure was located. The photographs in Figure 4 depict the correlation of the ejected pipe with the in-situ pipe and ditch location:

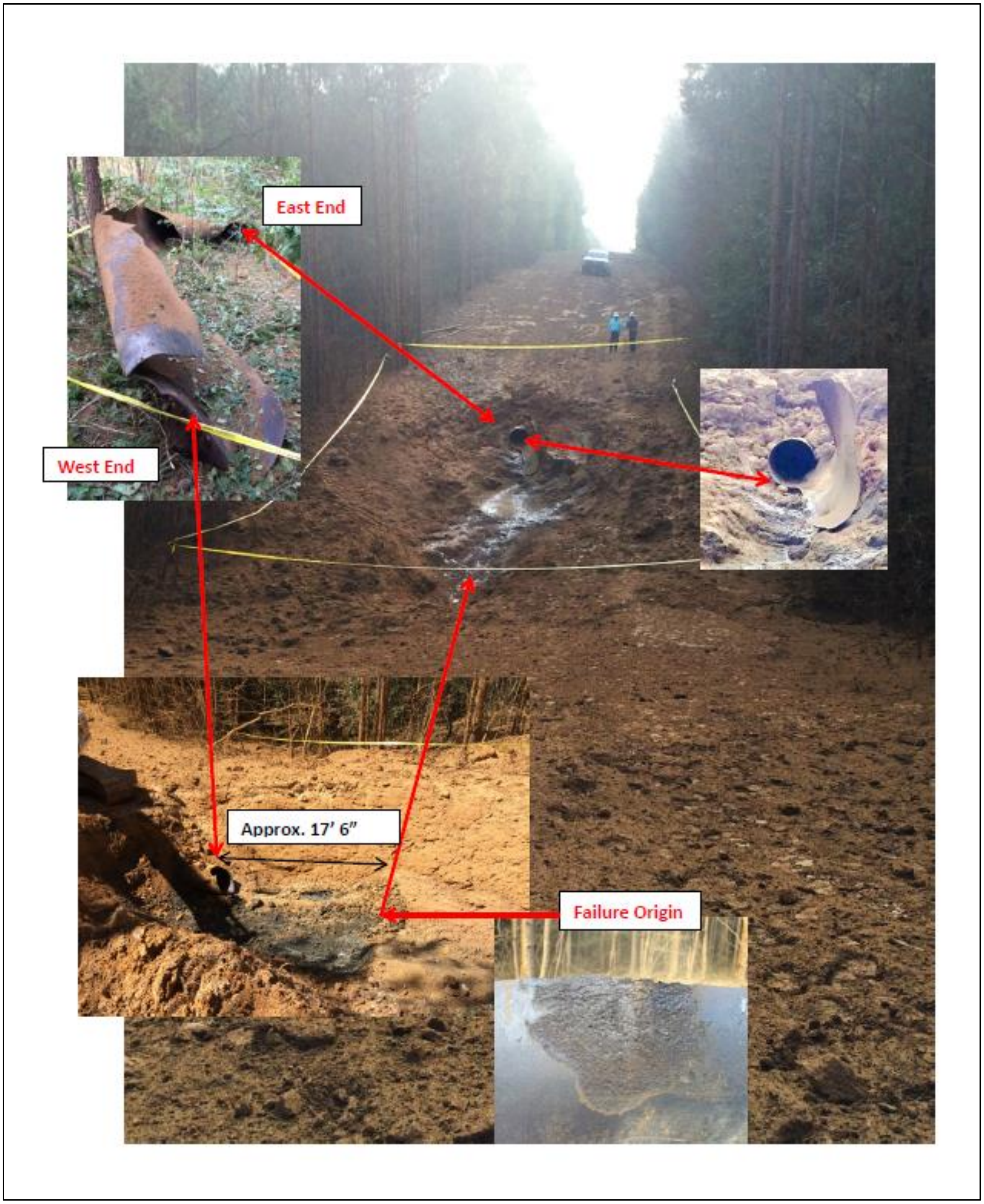


Figure 4 - Correlation of Ejected Pipe Segment with the Ditch and In Situ Pipe

Based on field observations, the SES and PHMSA stated that the preliminary determination of the cause of failure was localized environmental cracking in combination with external corrosion. The failure originated on the bottom of the pipe where it rested on a rock ledge outcrop in the otherwise relatively homogenous clay-like material of the ditch. The photos in Figure 4 show this outcropping, which is the dark grey, rocky material surrounded by orange clay soil. A more detailed description of the soil conditions can be found in the metallurgical failure analysis report in Appendix D.

The affected pipe sections were identified, their edges protected, and the segments prepared for transport to the SES laboratory in Houston, Texas. After that was accomplished the PHMSA investigator left the site.

The pipeline was located in a Class 1 rural area and no High Consequence Areas (HCA) were affected by the incident.

Metallurgical Examination

The SES completed a metallurgical failure analysis of the pipe from the incident and issued their findings in a report dated November 6, 2016. The report, which can be found in Appendix D, summarized the findings as follows:

> *Based on visual examination and metallurgical analyses of the pipe samples provided to SES along with information gathered during a visit to the Monroe failure site, SES concluded that the subject failure was the result of external corrosion in combination with near-neutral pH stress corrosion cracking (SCC). This damage occurred at about the 6:00 o'clock orientation where the soil supporting the pipeline contained rocky material that damaged the coating and likely shielded this area, rendering it difficult to maintain the CP potential. This rocky material supporting the pipe was part of a black layer of sedimentary deposits (which were readily seen in the ditch). The soil above and below this black layer consisted of sandy clay material and was not compacted to form hard or rock-like material.*
>
> *. . . .*
>
> *Based on SES's visual examination and metallurgical analyses of the samples provided, along with observations from a visit to the site, SES concluded that the Monroe failure was caused by a combination of corrosion and near-neutral pH stress corrosion cracking. The information available to SES did not allow a determination of the precise timing or exact conditions that led to the failure. However, it was apparent that corrosion enlarged cracks in the pipe, thereby significantly contributing to the failure.*
>
> *The mechanical properties of the pipe material were tested and found to meet the requirements of API 5LX in effect in 1948 (as well as current requirements). While the material toughness was low, this property alone did not play a significant role in the failure.*

PHMSA concurs with the findings in SES's metallurgical failure analysis report.

Investigation Findings & Contributing Factors

The failure was caused by a combination of factors that exacerbated localized corrosion in a limited area of low-pH stress corrosion cracking, thereby expanding the cracks until they led to failure. The failure, which was not readily apparent from the surface of the ground, was likely related to placement of the pipe on an area of rocky material that damaged the pipe's coating and thus contributed to external corrosion.

The TGT's subsequent examination of the MFL and TFI ILI data for 14 sites with similar signal indications revealed no SCC. These findings reinforce the difficulty in finding or predicting the conditions or locations that result in the combination of this type of low-level corrosion with SCC.

Appendixes

A Maps

B NRC Report

C Operator Incident Reports to PHMSA

D Metallurgical Failure Analysis Report

Pipeline and Hazardous Materials Safety Administration

NATIONAL PIPELINE MAPPING SYSTEM

FOR OFFICIAL USE ONLY

(b) (7)(F)

[redacted]

Legend

- Queried Incidents (Gas)
- Incidents (Gas)
- Gas Transmission Pipelines

500 m
1000 ft

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

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

Questions regarding this map or its contents can be directed to npms@dot.gov.

Projection: Geographic

Datum: NAD83

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

Date Printed: May 25, 2016

811 Know what's below. Call before you dig.

From: CMC-01 (OST)

Sent: Wednesday, September 09, 2015 5:43 PM

To: PHMSA PHP80 Response; PHMSA PHP400 SOUTHWEST

Subject: NRC#1128025: Pipeline - Union County, LA (176 miles NW of Baton Rouge, LA), natural gas release

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

NATIONAL RESPONSE CENTER 1-800-424-8802

GOVERNMENT USE ONLYGOVERNMENT USE ONLY***

Information released to a third party shall comply with any

applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1128025

INCIDENT DESCRIPTION

*Report taken by: CIV ANTONAY GREER at 18:22 on 09-SEP-15

Incident Type: PIPELINE

Incident Cause: UNKNOWN

Affected Area:

Incident occurred on 09-SEP-15 at 16:30 local incident time.

Affected Medium: AIR /ATMOSPHERE- NO OFF SITE IMPACT

REPORTING PARTY

Name: JAY JONES

Organization: BOARDWALK PIPELINES/ TEXAS GAS

Address: 610 WEST 2ND ST.

OWENSBORO, KY 42301

Email Address: jay.jones@bwpmlp.com

PRIMARY Phone: (270)6886800

Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY

Name: JAY JONES

Organization: BOARDWALK PIPELINES/ TEXAS GAS

Address: 610 WEST 2ND ST.

OWENSBORO, KY 42301

PRIMARY Phone: (270)6886800

INCIDENT LOCATION

County: UNION

State: LA

Latitude: 38° 50' 53" N

Longitude: 092° 28' 00" W

NEAR FOWLER RD. & TIGER BEND

RELEASED MATERIAL(S)

CHRIS Code: ONG Official Material Name: NATURAL GAS

Also Known As:

Qty Released: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

NATURAL GAS IS RELEASING FROM A 26" TRANSMISSION PIPELINE, DUE TO UNKNOWN CAUSES.

SENSITIVE INFORMATION

OSC,

THE POSITION THE RP PROVIDED IS INACCURATE. GIS PLACED THE NEAREST COORDINATES AT

LATITUDE: 32.844491N

LONGITUDE: -92. 283871

INCIDENT DETAILS

Pipeline Type: TRANSMISSION

DOT Regulated: YES

Pipeline Above/Below Ground: BELOW

Exposed or Under Water: NO

Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO   Fire Extinguished: UNKNOWN

INJURIES: NO   Hospitalized: Empl/Crew: Passenger:

FATALITIES: NO   Empl/Crew: Passenger: Occupant:

EVACUATIONS:NO   Who Evacuated: Radius/Area:

Damages: NO

Hours Direction of

Closure Type Description of Closure Closed Closure

N

Air:

N Major

Road: Artery:N

N

Waterway:

N

Track:

Environmental Impact: NO

Media Interest: UNKNOWN Community Impact due to Material:

REMEDIAL ACTIONS

BLOCK VALVES ARE BEING CLOSED, CREW ONSITE.

Release Secured: NO

Release Rate:

Estimated Release Duration:

WEATHER

Weather: UNKNOWN, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal:

State/Local:

State/Local On Scene:

State Agency Number:

NOTIFICATIONS BY NRC

AR DEPT OF ENVIRONMENTAL QUALITY (COMMAND CENTER)

09-SEP-15 18:37 (501)6820713

ARKANSAS POISON CENTER (MAIN OFFICE)

09-SEP-15 18:37 (501)6866161

AR STATE EMERGENCY SERVICES (MAIN OFFICE)

09-SEP-15 18:37 (501)6836700

CENTERS FOR DISEASE CONTROL (GRASP)

09-SEP-15 18:37 (770)4887100

DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)

09-SEP-15 18:37 (202)3661863

U.S. EPA VI (MAIN OFFICE)

(866)3727745

FLD INTEL SUPPORT TEAM NEW ORLEANS (SUPERVISOR, FIST NEW ORLEANS)

09-SEP-15 18:37 (504)5894224

JFO-LA (COMMAND CENTER)

09-SEP-15 18:37 (225)3366513

JFO-LA (FEMA JFO LA)

09-SEP-15 18:37 (225)3366513

LA DEPT OF ENV QUAL (MAIN OFFICE)

09-SEP-15 18:37 (225)2193640

LA DEPT OF NATURAL RESOURSES (OFFICE OF CONSERVATION)

09-SEP-15 18:37 (225)3425524

LA DEPT OF WILDLIFE AND FISHERIES (MAIN OFFICE)

09-SEP-15 18:37 (337)

LA GOV OFFICE HS AND EMERGENCY PREP (MAIN OFFICE)

09-SEP-15 18:37 (225)9257500

LA GOV OFFICE HS AND EMERGENCY PREP (SITUATIONAL AWARENESS N.E. LOUISIA

09-SEP-15 18:37 (225)9257500

LA OFFICE OF GOV (MAIN OFFICE)

09-SEP-15 18:37 (225)2195800

LA OFFICE OF PUBLIC HEALTH (MAIN OFFICE)

09-SEP-15 18:37 (888)2937020

NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)

09-SEP-15 18:37 (202)2829201

NOAA RPTS FOR LA (MAIN OFFICE)

09-SEP-15 18:37 (206)5264911

NATIONAL RESPONSE CENTER HQ (AUTOMATIC REPORTS)

09-SEP-15 18:37 (202)2671136

NTSB PIPELINE (MAIN OFFICE)

09-SEP-15 18:37 (202)3146293

REPORTING PARTY (RP SUBMITTER)

09-SEP-15 18:37

SECTOR LOWER MISSISSIPPI RIVER (AUTO NRC NOTIFICATIONS)

09-SEP-15 18:37 (225)2985400

LA STATE POLICE (MAIN OFFICE)

09-SEP-15 18:37 (225)9256595

LA STATE POLICE (ANALYTICAL AND FUSION EXCHANGE)

09-SEP-15 18:37 (225)9254192

MSU BATON ROUGE (MAIN OFFICE)

09-SEP-15 18:37 (225)2985400

DEPT OF ENERGY STPR (STRATEGIC PETROLEUM RESERVE-EMERGENCY MGMT)

09-SEP-15 18:37 (504)7344113

USCG DISTRICT 8 (MAIN OFFICE)

09-SEP-15 18:37 (504)5896225

USCG DISTRICT 8 (PLANNING)

09-SEP-15 18:37 (504)6712080

ADDITIONAL INFORMATION

*** END INCIDENT REPORT #1128025 ***

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

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

NOTICE: This report is required by 49 CFR Part 191. 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: 2137-0522 EXPIRATION DATE: 10/31/2017
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	10/08/2015
	No.	20150120 - 17094 (DOT Use Only)

INCIDENT REPORT - GAS TRANSMISSION AND GATHERING 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 2137-0522. All responses to this collection of information are mandatory. Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

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

PART A - KEY REPORT INFORMATION

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

Last Revision Date:	05/23/2016
1. Operator's OPS-issued Operator Identification Number (OPID):	19270
2. Name of Operator	TEXAS GAS TRANSMISSION, LLC
3. Address of Operator:	
3a. Street Address	9 GREENWAY PLAZA SUITE 2800
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code:	77046
4. Local time *(24-hr clock)* and date of the Incident:	09/09/2015 16:30
5. Location of Incident:	
Latitude:	32.848632
Longitude:	-92.285693
6. National Response Center Report Number (if applicable):	1128025
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	09/09/2015 17:23
8. Incident resulted from:	Unintentional release of gas
9. Gas released: (select only one, based on predominant volume released)	Natural Gas
- Other Gas Released Name:	
10. Estimated volume of commodity released unintentionally - Thousand Cubic Feet (MCF):	42,100.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	
12. Estimated volume of accompanying liquid release (Barrels):	
13. Were there fatalities?	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 fatalities (sum of above)	
14. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
14a. Operator employees	
14b. Contractor employees working for the Operator	
14c. Non-Operator emergency responders	
14d. Workers working on the right-of-way, but NOT associated with this Operator	
14e. General public	
14f. Total injuries (sum of above)	
15. Was the pipeline/facility shut down due to the incident?	No
- If No, Explain:	Rerouted gas flow

- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	
15b. Local time pipeline/facility restarted	
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	No
17. Did the gas explode?	No
18. Number of general public evacuated:	16
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident– effective 10-2014, changed from "Incident" to "failure"	09/09/2015 16:33
19b. Local time operator resources arrived on site	09/09/2015 17:30

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Incident onshore?	Yes
- Yes (Complete Questions 2-12)	
- No (Complete Questions 13-15)	
If Onshore:	
2. State:	Louisiana
3. Zip Code:	71241
4. City	Farmerville
5. County or Parish	Union
6. Operator designated location	Milepost/Valve Station
Specify:	28+4276
7. Pipeline/Facility name:	Main Line System
8. Segment name/ID:	MLS
9. Was Incident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Incident :	Pipeline Right-of-way
11. Area of Incident (as found) :	Underground
Specify:	Under soil
Other – Describe:	
Depth-of-Cover (in):	48
12. Did Incident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
Name of body of water (If commonly known):	
Approx. water depth (ft) at the point of the Incident:	
Select:	
If Offshore:	
13. Approx. water depth (ft) at the point of the Incident:	
14. Origin of Incident:	
- If "In State waters":	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- If "On the Outer Continental Shelf (OCS)":	
- Area:	
- Block #:	
15. Area of Incident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility: - Interstate - Intrastate	Interstate
2. Part of system involved in Incident:	Onshore Pipeline, Including Valve Sites
3. Item involved in Incident:	Pipe
- If Pipe – Specify:	Pipe Body
3a. Nominal diameter of pipe (in):	26
3b. Wall thickness (in):	.281
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	52,000

3d. Pipe specification:	API 5L
3e. Pipe Seam – Specify:	Flash Welded
- If Other, Describe:	
3f. Pipe manufacturer:	A. O. Smith
3g. Year of manufacture:	1949
3h. Pipeline coating type at point of Incident – 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. Mainline valve manufacturer:	
3j. Year of manufacture:	
- If Other, Describe:	
4. Year item involved in Incident was installed:	1949
5. Material involved in Incident:	Carbon Steel
- If Material other than Carbon Steel or Plastic – Specify:	
6. Type of Incident 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):	26
by in. (length circumferentially or axially):	552
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Class Location of Incident:	Class 1 Location
2. Did this Incident occur in a High Consequence Area (HCA)?	No
- If Yes:	
2a. Specify the Method used to identify the HCA:	
3. What is the PIR (Potential Impact Radius) for the location of this Incident? Feet:	511
4. Were any structures outside the PIR impacted or otherwise damaged due to heat/fire resulting from the Incident?	No
5. Were any structures outside the PIR impacted or otherwise damaged NOT by heat/fire resulting from the Incident?	No
6. Were any of the fatalities or injuries reported for persons located outside the PIR?	No
7. Estimated Property Damage :	
7a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator – effective 6-2011, "paid/reimbursed by the Operator" removed	$ 5,000
Estimated cost of gas released unintentionally – effective 6-2011, moved to item 7f	
Estimated cost of gas released during intentional and controlled blowdown – effective 6-2011, moved to item 7g	
7b. Estimated cost of Operator's property damage & repairs	$ 207,439
7c. Estimated cost of Operator's emergency response	$ 7,500
7d. Estimated other costs	$ 0
Describe:	
7e. Property damage subtotal (sum of above)	$ 219,939
<u>Cost of Gas Released</u>	
7f. Estimated cost of gas released unintentionally	$ 133,367
7g. Estimated cost of gas released during intentional and controlled blowdown	$ 114,655
7h. Total estimated cost of gas released (sum of 7.f & 7.g above)	$ 248,022
Total of all costs	$ 467,961

PART E - ADDITIONAL OPERATING INFORMATION	
1. Estimated pressure at the point and time of the Incident (psig):_	766.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	810.00
Added 10-2014 2a. MAOP established by 49 CFR section:	192.619(a)(1)
- If Other, specify:	
3. Describe the pressure on the system or facility relating to the Incident:	Pressure did not exceed MAOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Incident operating under an established pressure restriction with pressure limits below those normally allowed by the MAOP?	No
- If Yes - (*Complete 4a and 4b below)*	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5e. below):*	
5a. Type of upstream valve used to initially isolate release source:	Manual
5b. Type of downstream valve used to initially isolate release source:	Manual
5c. Length of segment isolated between valves (ft):	52,800
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 build-up	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other	
- If Other, Describe:	
5f. Function of pipeline system:	Transmission System
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Incident?	Yes
- If Yes:	
6a. Was it operating at the time of the Incident?	Yes
6b. Was it fully functional at the time of the Incident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
7. How was the Incident initially identified for the Operator?	Notification from Emergency Responder
- If Other – Describe:	
7a. If "Controller", "Local Operating Personnel, including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 7, specify:	
8. 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 Incident?	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)*	Incident occurred at a pressure below MAOP
- If Yes, Descr be 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 Incident, 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. How many were tested:	
1b. How many failed:	
2. As a result of this Incident, 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. How many were tested:	
2b. How many failed:	

PART G - APPARENT CAUSE

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

Apparent Cause:	G5 - Material Failure of Pipe or Weld

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

Corrosion Failure – Sub-cause:	
- 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 incident?	
- If Yes, Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the incident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the incident?	
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:	
- If Other, Describe:	
7. Cause 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	
- Drop-out	
- Other	
- If Other, Describe:	
10. Was the gas/fluid treated with corrosion inh bitors 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 Incident" (from PART C, Question 3) is Pipe or Weld.	
14. Has one or more internal inspection tool collected data at the point of the Incident?	
14a. 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 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:	
If Other, Describe:	
15. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes,	

Most recent year tested:	
Test pressure (psig):	
16. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
17. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
17a. 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 examined:	
- Guided Wave Ultrasonic	
Most recent year examined:	
- Handheld Ultrasonic Tool	
Most recent year examined:	
- Wet Magnetic Particle Test	
Most recent year examined:	
- Dry Magnetic Particle Test	
Most recent year examined:	
- Other	
Most recent year examined:	
If Other, 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, Descr be:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Descr be:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Descr be:	
- 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 Incident generated in conjunction with an extreme weather event?	
6a. If yes, specify: *(select all that apply)*:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage *only one **sub-cause** can be picked from shaded left-hand column*	
Excavation Damage – Sub-Cause:	
- If Previous Damage Due to Excavation Activity: Complete Questions 1-5 ONLY IF the "Item Involved in Incident" (From Part C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Incident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Year:	
- Ultrasonic	
Year:	
- Geometry	
Year:	
- Caliper	

Year:	
- Crack	
Year:	
- Hard Spot	
Year:	
- Combination Tool	
Year:	
- Transverse Field/Triaxial	
Year:	
- Other:	
Year:	
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 Incident?	
- 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 Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident 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 Incident 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	
Year:	
- Guided Wave Ultrasonic	
Year:	
- Handheld Ultrasonic Tool	
Year:	
- Wet Magnetic Particle Test	
Year:	
- Dry Magnetic Particle Test	
Year:	
- Other	
Year:	
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? - Yes - No	

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 vis ble 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, then one predominant second level CGA-DIRT Root Cause as well*):	
- Predominant first level CGA-DIRT 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 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, Descr be:	
- If Previous Mechanical Damage NOT Related to Excavation: Complete Questions 3-7 ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Incident?	
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 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:	
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 Incident?	
- 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 Incident :	

Most recent year conducted:	
- If Yes, but the point of the Incident 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 Incident 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 - Pipe, Weld, or Joint Failure	**Use this section to report material failures ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is "Pipe" or "Weld."** Only one **sub-cause** can be selected from the shaded left-hand column

Pipe, Weld or Join Failure – Sub-Cause:	Environmental Cracking-related
1. The sub-cause shown above is based on the following *(select all that apply)*:	
- Field Examination	Yes
- Determined by Metallurgical Analysis	Yes
- Other Analysis	
- If "Other Analysis", Describe	
- Sub-cause is Tentative or Suspected; Still Under Investigation *(Supplemental Report required)*	
- If Construction, Installation, or Fabrication-related Or If Original Manufacturing-related:	
2. List contr buting 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:	Stress Corrosion Cracking
- If 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	Yes
- 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	No

the Incident?	
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 Incident?	Yes
- If Yes:	
Most recent year tested:	1976
Test pressure (psig):	1,012.00
7. Has one or more Direct Assessment been conducted on the pipeline segment?	No
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident 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 Incident since January 1,2002?	No
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 - Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify:	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	

- Stopple/Control Fitting	
- Pressure Regulator	
- ESD System Failure	
- Other	
- If Other, Describe:	
- If Compressor or Compressor-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 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 gas/fluid	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 – Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
- If Underground Gas Storage, Pressure Vessel, or Cavern Allowed or Caused to Overpressure:	
1. Specify:	
- If Other, Describe:	
- If Other Incorrect Operation:	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Incident 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 Incident:	
5. Was the task(s) that led to the Incident 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 Incident Cause - only one **sub-cause** can be selected from the shaded left-hand column	
Other Incident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	

2. Specify:	

PART - H NARRATIVE DESCRIPTION OF THE INCIDENT

Texas Gas experienced a pipeline failure of its Main Line System 26" No. 1 line in Union Parish, Louisiana. There were no injuries. The cause remains under investigation.

3-15-16 Update to finalize report including cost and cause. Based on Stress Engineering's visual examination and metallurgical analyses of the samples provided, along with observations from a visit to the site, SES concluded that the Monroe failure was caused by a combination of corrosion and near-neutral pH stress corrosion cracking. The information available to SES did not allow a determination of the precise timing or exact conditions that led to the failure. However, it was apparent that corrosion enlarged cracks in the pipe, thereby significantly contributing to the failure. The mechanical properties of the pipe material were tested and found to meet the requirements of API 5LX in effect in 1948 (as well as current requirements). While the material toughness was low, this property alone did not play a significant role in the failure.

4-29-16 Revised cause on Part G to reflect laboratory analysis findings.

5-23-16 Revised per PHMSA request to report cause under section G5 instead G1.

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Appendix D

Metallurgical Failure Analysis Report

This document is on file at PHMSA