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

Principal Investigator	Gery Bauman/Public Utilities Commission of Ohio (PUCO)
Senior Accident Investigator	Brian Pierzina/Karen Butler
Region Director	David Barrett/Allan Beshore
Date of Report	7/30/2015
Subject	Failure Investigation Report—Tennessee Gas Pipeline Company—Material Failure—Girth Weld

Operator, Location, & Consequences

Date of Failure	3/1/2011
Commodity Released	Natural Gas
City/County & State	Cumberland/Guernsey, OH
OpID & Operator Name	19160 Tennessee Gas Pipeline Company
Unit # & Unit Name	9413 DIVISION E [IA]
SMART Activity #	133678
Milepost/Location	Line 200-1/209-1 + 2258
Type of Failure	Rupture, Material Failure, Girth Weld
Fatalities	0
Injuries	0
Description of area impacted	Class 1, Rural area, Non-HCA
Total Costs	$ 389,949

Executive Summary

On March 1, 2011, at approximately 7:15 a.m. EST,[1] Tennessee Gas Pipeline Company (TGP) personnel detected a natural gas release on the 26-inch diameter 200-1 pipeline downstream of the 209 Compressor Station in Guernsey County, near Cumberland, Ohio. The employees heard a hissing sound downstream (northeast) of the compressor station when they reported to work in the morning. After investigating, they confirmed a release coming from the 200-1 pipeline approximately 2,250 feet downstream of the compressor station. Immediate measures were taken to shut down and isolate the pipeline, including closing main line block valves (MLBVs) upstream and downstream from the release location.

The failure occurred in a wooded area near a pasture (Class 1 location, Rural, Non-HCA) approximately 1,200 feet from the nearest residence, and was discovered to be the result of a ruptured girth weld. The failed weld was removed—along with the adjacent welds upstream and downstream from the failure location—and sent to an independent metallurgical laboratory for analysis. The metallurgical analysis determined the failure was the result of a crack around the top portion of the girth weld dating back to 1950, the year of the original construction. The crack was what is referred to as an underbead crack, cold crack, or hydrogen-assisted crack. It was approximately 31 inches long circumferentially, centered from the 10:00 o'clock to 2:40 o'clock position on the pipe. Stresses associated with pipe bend, possible ground movement, and/or operational changes may have contributed to the eventual failure of the weld. When the first cut was made to remove the failed pipe the pipe ends shifted, indicating the presence of residual stresses on the pipeline. Additional cracks were identified outside of the failed portion of the girth weld, and the adjacent girth weld upstream from the failure had a similar crack that was determined to date to original construction, but was not leaking.

Based upon information provided by the TGP, it appears the failure occurred at 3:42 a.m. at a pressure of 709 pounds per square inch gage (psig). There were no injuries or evacuations associated with this incident, and the escaping gas did not ignite. The total reported costs associated with emergency response, pipe replacement, and site clean-up were $389,949.

System Details

The TGP is an interstate natural gas transmission pipeline operator with approximately 12,000 miles of pipeline, including 876 miles in Ohio. The TGP system in Ohio consists of four essentially parallel pipelines that travel across the Ohio River near Portsmouth, Ohio, in a northeasterly direction, ending near Boardman, Ohio. The four pipelines generally, but not always, share a common right-of-way. The failure occurred on the Line 200-1 pipeline, a 26-inch diameter, 0.281-inch wall thickness, API 5LX Grade X-52, electric flash-welded (EFW) pipe manufactured by A.O. Smith. The pipeline was coated with coal tar enamel and asbestos wrap, and cathodically protected with impressed current. This pipeline was constructed in 1950 with a maximum allowable operating pressure (MAOP) of 790 psig. The pipeline section containing the girth weld was hydrostatically pressure tested without failure on September 27, 1969, and was in a no-flow condition at the time the leak was discovered due to ongoing downstream pipeline repairs being performed on Line Section 214-1. When the pipeline was constructed in 1950, pipeline girth welds were not typically nondestructively tested. In 2004, the TGP ran a high-resolution Magnetic Flux Leakage (MFL) and Caliper In-line inspection (ILI). The ILI data was examined for

[1] All times are Eastern Standard Time (EST) unless otherwise noted.

indications of dents and metal loss, but was not subjected to an analysis that considered girth weld defects.

Events Leading up to the Failure

On February 10, 2011, at approximately 10:30 p.m., the TGP experienced a pipeline rupture (girth weld failure) on the Line 214-4 pipeline near Hanoverton, Ohio. Station 209 was operating when this failure occurred, but was taken offline as a result of the rupture and subsequent fire approximately 15 minutes later. As the emergency response to the Hanoverton incident progressed, TGP Incident Command determined it would be necessary to bring Station 209 back online to maintain service to customers. The request to bring Station 209 back online (for Lines 1, 2, and 3) was made at at 10:56 p.m. It was unknown at that time that the auto-close valves for all four pipelines at Valve Station 215 had closed due to the rupture and fire. When Station 209 was brought back online, the gas discharge pressure rose rapidly from 740 psig to 765 psig between 12:18 a.m. and 12:23 a.m., then dropping to 743 psig by 12:28 a.m. From that point on discharge pressure rose gradually, reaching a maximum recorded pressure of 782 psig at 1:24 a.m., when Incident Command requested Station 209 be shut down. When it was determined that all four auto-close valves at Valve Station 215 had closed, and the TGP system isolated at that location, alternative means of providing service to distribution customers was established. This allowed Station 209 to remain offline until after the necessary repairs at 215-1 were completed; those repairs were still in process when the March 1, 2011, incident occurred. There were no reported maintenance activities on the section of pipe just downstream of Compressor Station 209 in the area of the leak prior to March 1, 2011.

Emergency Response

The leak was initially discovered by TGP employees when they reported for work at Compressor Station 209 after they investigated a sound of escaping gas that could be heard from the station. Only two of the four pipelines in the area of the failure share a common right-of-way, so the employees were quickly able to determine the release was coming from Line 1. The employees then began the process of isolating the pipeline, closing MLBV 209-1 (upstream from the failure) at Compressor Station 209 at 8:00 a.m. and MLBV 210-1 (downstream from the failure) at 8:20 a.m. This isolated approximately 12 miles of Line 1, including the failure location. The pressure on Line 1 was then monitored for a period of time, with a pressure drop from 658 psig to 464 psig observed from 8:23 a.m. to 9:20 a.m. After receiving this additional confirmation that Line 1 was leaking, the TGP employees prepared to blowdown the section of Line 1 between MLBV 209-1 and MLBV 210-1. The blowdown process began at 10:47 a.m. and was completed by 12:30 p.m. There was no fire or explosion associated with the incident. The TGP notified the National Response Center (NRC) at 10:12 a.m. (NRC Report #968824), reporting that "a 26-inch steel pipeline appears to have a leak due to unknown causes." Both the Public Utilities Commission of Ohio (PUCO) and the Pipeline and Hazardous Materials Safety Administration (PHMSA) Central Region Inspectors were dispatched to investigate. The PUCO inspector was in the area inspecting a different pipeline operator, and arrived on-site at 11:25 a.m. The inspectors were able to provide field observations, gather background information, and monitor investigation and repair activities. Excavation of the failure location did not begin until the morning of March 2, 2011.

Summary of Return-to-Service

PHMSA issued a Notice of Proposed Safety Order (NOPSO) to the TGP (CPF No. 3-2011-1001S) on March 11, 2011, addressing both the failure on February 10, 2011, at Line 214-4, and the failure on March 1, 2011, at 209-1. The NOPSO provisions required a written restart plan, 20% pressure reduction, airborne instrumented leak survey, accelerated patrol surveillance activities, 3rd-party mechanical and

metallurgical testing and failure analysis, historical ILI data re-analysis, performance of additional ILI, evaluation of the results for girth weld anomalies, analysis of Supervisory Control and Data Acquisition (SCADA) activities, root cause analysis, development and implementation of an integrity verification and remedial work plan, and monthly status reports. Good faith settlement discussions between the TGP and PHMSA culminated in a Consent Agreement that described the work to be performed to remediate the integrity risks associated with the pipelines.

On March 22, 2011, the TGP replaced 86 feet of the Line 1 pipe with pre-tested pipe. Even though the pipeline remained out of service, it was purged and loaded with natural gas to facilitate the required leakage survey from 209-1 to 210-1. Following the leakage survey, this section of Line 1 remained out of service, isolated at a pressure of 475 psig. During May 2011, with PHMSA's approval, the TGP temporarily increased the pressure on Line 1 from 209-1 to 214-1 in order to facilitate the cleaning tool, gauge tool, and inspection tool runs required by the Consent Agreement. These activities were completed by May 12, 2011, after which the section between 209-1 and 210-1 was isolated once more and locked in at a pressure of 522 psig. Following investigation and remediation of anomalies reported by the prior and most recent ILI reviews, the TGP requested—and was granted—permission to return the 209 to 210 section of Line 1 to service at full operating pressure. This was completed on October 28, 2011.

Investigation Details

After the area of the rupture was made safe, the rupture site was examined by employees of the TGP, PHMSA, and the Gas Pipeline Safety Section of PUCO. Records were requested regarding the history and operation of the pipeline, and the TGP hired Det Norske Veritas (DNV) to complete a metallurgical investigation of the failure. During the pipe removal process, the upstream and downstream welds were radiographed and crack-like indications were observed in the upstream weld. As a result, the failed girth weld and both the upstream and downstream welds were sent to the DNV for metallurgical investigation.

Pipe sections involving the three girth welds were removed and shipped to the DNV's Columbus location for a metallurgical investigation to determine the cause of the failure. The TGP expanded their root cause analysis (RCA) associated with the February 10, 2011, incident to include this girth weld failure. The RCA team was comprised of subject matter experts from the TGP and outside contractors. Additionally, soil scientists from Battelle Memorial Institute conducted a geologic and soil investigation into the failure.

The results of the metallurgical analysis[2] offered the following conclusions and discussion:

> The results of the metallurgical analysis indicate that the leak initiated at a pre-existing crack in a field girth weld. The crack was 2.6 feet long, circumferentially, and was located on the inside of the pipe between the 10:00 and 2:40 o'clock orientations. The maximum depth of the crack was 0.317 inches (79% through wall based on a pipe wall/girth weld thickness of 0.399 inches). The pre-existing crack initiated at the toe of the root pass in the heat-affected zone of the weld. The crack propagated primarily in the weld metal. The crack did alternate between the upstream and downstream root pass as it propagated. This type of crack is referred to as an under-bead crack, cold crack, or hydrogen assisted crack. A discussion of the factors related to hydrogen-assisted cracking is given in Appendix B of the metallurgical report.

[2] DNV Final Report—Metallurgical Analysis of Girth Weld Leak on Tennessee Gas Pipeline's 200-1 Line at Milepost 209-1 + 0.44—May 20, 2011.

The primary cause of the leak was the presence of the pre-existing weld crack. A contributing factor in the failure was tensile axial stresses acting on the girth weld. The presence of the weld crack near the top of the pipe suggests that bending stresses acted on the pipe to place the crack in tension. This is consistent with shifting of the pipe after the initial field cut, in which the upstream end shifted upwards approximately 2.5 inches. Approximately 91 feet of the pipeline was excavated (approximately 45.5 feet on both sides of the failed girth weld) at the time of the initial cut.

Below is a summary of observations from the metallurgical analysis.

- The leak occurred at a field girth weld.
- A pre-existing weld crack was associated with the leak.
- The pre-existing crack was approximately 2.6 feet long, circumferentially, and located
- between the 10:00 and 2:40 o'clock orientations.
- The maximum depth of the crack was approximately 0.317 inches, corresponding to 79% through wall based on a pipe wall/girth weld thickness of 0.399 inches. The final brittle fracture was approximately 0.08 inches deep corresponding to 21% of the pipe wall / girth weld thickness.
- The crack originated at the toe of the weld root pass and extended through the weld metal of the girth weld.
- Intergranular fractographic features were present in Regions 1 and 2 of the crack.

Findings and Contributing Factors

1. There was a change in the operational history of the Cumberland Compressor Station immediately upstream of the failed girth weld. The pipeline was shut-in due to the repair of the downstream girth weld failure, and the ambient temperature at the time of failure was 24 degrees Fahrenheit. The cooler operating temperature of the pipeline could have increased tensile stresses due to thermal contraction of the pipe.
2. Typically, pipelines are bent during construction to conform to local topography. The section of pipe in the immediate vicinity of the girth weld contained a 7.9-degree sag bend; upon replacement of the pipeline section, however, a sag bend of 5.5 degrees was installed to fit the topography. The difference of 2.4 degrees between the original and replacement construction indicates the possibility of bending stresses acting across the weld.
3. A geological analysis of the soil and the topography of the pipeline right-of-way in the vicinity of the failed weld indicated soil creep perpendicular to the pipeline. This extremely slow ground movement could increase the tensile stresses across the girth weld over time, leading to its failure.
4. The results of the DNV metallurgical investigation showed the failed girth weld contained a preexisting crack that extended through part of the girth weld. The preexisting crack initiated at the toe of the root bead and penetrated through part of the weld. The crack was 2.6 feet long circumferentially, and had a maximum depth of 0.317 inches (79% of the way through the wall based on a total weld thickness of 0.399 inches). The laboratory classified the crack as a hydrogen crack, also known as an under-bead crack, cold crack, or hydrogen-assisted crack. The conculsion that it was a hydrogen crack that led to this failure is supported by the metallurgy of the pipe and the welding electrodes used to complete the weld, as well as experience gained

regarding welding since the pipeline was built in 1950. No signs of fatigue were observed; the crack formed during construction of the pipeline and remained dormant from the date of construction until the time of failure.

5. The restart of Station 209 during the Line 214-4 incident on February 10-11, 2011, was initiated shortly after the incident. Fires were still burning at this time, and the status of Lines 1, 2, and 3 was unconfirmed. As a result of all four pipelines being isolated at Valve Station 215, the discharge pressure at 209-1 reached at least 782 psig prior to the station being shut down again. The pressure records provided by the TGP for the period following this event show that the pressure at 209 was maintained between 630 psig and 670 psig until the end of February. The pressure began to increase steadily on February 28th, rising from 670 psig to 709 psig, at which point the failure occurred. It's possible this pressure cycle, just 18 days before the failure, may have been sufficient to destabilize the previously dormant defect.

Appendices

A Map and Photographs

B NRC Report

C Operator's Report

D Metallurgical Analysis

E Root Cause Analysis (RCA)

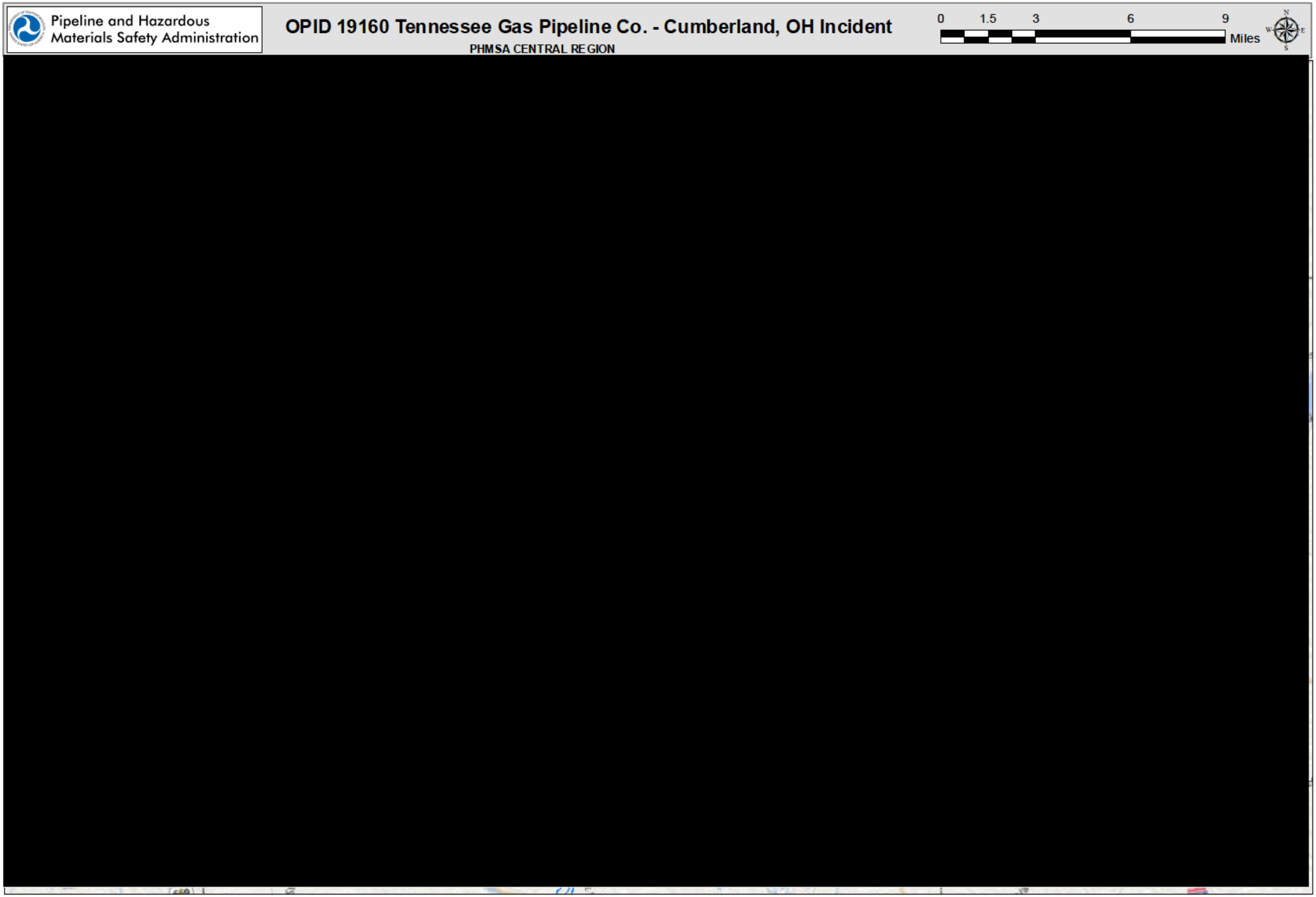
Pipeline and Hazardous Materials Safety Administration
OPID 19160 Tennessee Gas Pipeline Co. - Cumberland, OH Incident
PHMSA CENTRAL REGION
0 1.5 3 6 9
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Photo 1 view of leak site looking south down the right-of-way. The compressor station can be seen in the distance. The disturbed soil was blown from the ground as a result of the failed girth weld.

Photo 2 shows the excavation around the failed girth weld.

Photo 3 shows the failed girth weld.

Photo 4 shows a close-up of the top of the failed girth weld.

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 # 968824

INCIDENT DESCRIPTION

*Report taken at 10:12 on 01-MAR-11
Incident Type: PIPELINE

Incident Cause: UNKNOWN
Affected Area:
The incident was discovered on 01-MAR-11 at 09:15 local time.

Affected Medium: AIR INTO THE AIR

SUSPECTED RESPONSIBLE PARTY

Organization: TENNESSEE GAS PIPELINE
HOUSTON, TX 77046

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

SEE LAT/LONG County: GUERNSEY
COUNTY RD 15
CLAYSVILLE RD
City: CLAYSVILLE State: OH Zip: 77046
Latitude: 39 57' 12" N

Longitude: 081 40' 33" W

RELEASED MATERIAL(S)

CHRIS Code: ONG Official Material Name: NATURAL GAS

Also Known As:
Qty Released: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

THE CALLER IS REPORTING THAT A 26 INCH STEEL PIPELINE APPEARS TO HAVE A LEAK DUE TO UNKNOWN CAUSES. AN UNKNOWN AMOUNT OF NATURAL GAS WAS RELEASED TO THE ATMOSPHERE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
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				Major Artery: N
Waterway:	N				
Track:	N				

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

THEY HAVE ISOLATED THE PIPELINE AND WILL DEPRESSURE IT.

Release Secured: NO

Release Rate:
Estimated Release Duration:

WEATHER

Weather: PARTLY CLOUDY, 32°F Wind speed: 2 MPH Wind directi

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE

State/Local: OH PUC

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

NOTIFICATIONS BY NRC

ATLANTIC STRIKE TEAM (MAIN OFFICE)
01-MAR-11 10:19

USCG ICC (ICC ONI)
01-MAR-11 10:19

CGIS RAO ST. LOUIS (COMMAND CENTER)
01-MAR-11 10:19

DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
01-MAR-11 10:19

U.S. EPA V (MAIN OFFICE)
01-MAR-11 10:21

NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
01-MAR-11 10:19

NOAA RPTS FOR OH (MAIN OFFICE)
01-MAR-11 10:19

OHIO DEPARTMENT OF HEALTH (OHDOH)
01-MAR-11 10:19

SECTOR OHIO VALLEY (COMMAND CENTER)
01-MAR-11 10:19

OH EPA ATTN: DUTY OFFICER (MAIN OFFICE)
01-MAR-11 10:19

OH EPA ATTN: DUTY OFFICER (SOUTHEAST DISTRICT OFFICE)
01-MAR-11 10:19

ADDITIONAL INFORMATION

NO ADDITIONAL INFORMATION.

***** END INCIDENT REPORT # 968824 *****

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 viola ion 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: 10/31/2016
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	03/28/2011
	No.	20110036 - 16819 --- (DOT Use Only)

INCIDENT REPORT - GAS TRANSMISSION AND GATHERING 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/library/forms.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	**Yes**
Last Revision Date:	07/20/2015		
1. Operator's OPS-issued Operator Identification Number (OPID):	19160		
2. Name of Operator	TENNESSEE GAS PIPELINE COMPANY		
3. Address of Operator:			
3a. Street Address	1001 LOUISIANA ST SUITE 1000		
3b. City	HOUSTON		
3c. State	Texas		
3d. Zip Code:	77002		
4. Local time *(24-hr clock)* and date of the Incident:	03/01/2011 07:15		
5. Location of Incident:			
Latitude:	39.945198		
Longitude:	-81.680369		
6. National Response Center Report Number (if applicable):	968824		
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	03/01/2011 10:12		
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):	29,745.00		
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	13,338.00		
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?	Yes		
- If No, Explain:			

- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	03/01/2011 08:20
15b. Local time pipeline/facility restarted	03/22/2011 16:09
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	No
17. Did the gas explode?	No
18. Number of general public evacuated:	0
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident– effective 10-2014, changed from "Incident" to "failure"	03/01/2011 07:15
19b. Local time operator resources arrived on site	03/01/2011 08:00
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:	Ohio
3. Zip Code:	43732
4. City	Cumberland
5. County or Parish	Guernsey
6. Operator designated location	Milepost/Valve Station
Specify:	209-1@2258
7. Pipeline/Facility name:	Line 200-1
8. Segment name/ID:	Valve Section 209-1
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 – Descr be:	
Depth-of-Cover (in):	33
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:	Weld, including heat-affected zone
- If Pipe – Specify:	
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:	Exceeds API 5L
3e. Pipe Seam – Specify:	Flash Welded
- If Other, Describe:	
3f. Pipe manufacturer:	A.O. Smith
3g. Year of manufacture:	1950
3h. Pipeline coating type at point of Incident – Specify:	Coal Tar
- If Other, Describe:	
- If Weld, including heat-affected zone – Specify:	Pipe Girth Weld
- If Other, Describe:	
- If Valve – Specify:	
- If Mainline – Specify:	
- If Other, Describe:	
3i. Mainline valve manufacturer:	
3j. Year of manufacture:	
- If Other, Descr be:	
4. Year item involved in Incident was installed:	1950
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:	Circumferential
- If Other – Descr be:	
Approx. size: in. (widest opening):	.4
by in. (length circumferentially or axially):	31.2
- 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:	504
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	$ 10,000
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	$ 200,825
7c. Estimated cost of Operator's emergency response	$ 6,800
7d. Estimated other costs	$ 0
Describe:	
7e. Property damage subtotal (sum of above)	$ 217,625
Cost of Gas Released	
7f. Estimated cost of gas released unintentionally	$ 118,980
7g. Estimated cost of gas released during intentional and controlled blowdown	$ 53,344
7h. Total estimated cost of gas released (sum of 7.f & 7.g above)	$ 172,324
Total of all costs	$ 389,949

PART E - ADDITIONAL OPERATING INFORMATION	
1. Estimated pressure at the point and time of the Incident (psig):_	709.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	790.00
Added 10-2014 2a. MAOP established by 49 CFR section:	192.619(a)(3)
- If Other, specify:	
3. Descr be 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):	63,307
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?	No
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	No
7. How was the Incident initially identified for the Operator?	Local Operating Personnel, including contractors
- 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:	Operator employee
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)*	Pressures were never abnormal or in excess of MAOP.
- If Yes, Describe 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 inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in 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, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If Other Natural Force Damage:	
5. Descr be:	
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 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, 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, Describe:	
- 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:	Construction-, Installation-, or Fabrication-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	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress	Yes
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- If Other, Descr be:	
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	Yes
- Arc Burn	
- Crack	Yes
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other	
- If Other, Descr be:	
5. Has one or more internal inspection tool collected data at the point of	Yes

the Incident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	Yes
Most recent year run:	2004
- Ultrasonic	
Most recent year run:	
- Geometry	Yes
Most recent year run:	2004
- 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:	
Descr be:	
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:	1969
Test pressure (psig):	1,054.00
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:	
Descr be:	
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

On March 1, 2011, Tennessee Gas Pipeline (TGP) Company personnel arrived to begin their work day at Compressor Station 209 near Cumberland, Ohio, and noticed an audible sound like releasing gas just northeast of the station yard. Upon investigation, the point of the release was found in TGP's 26" 200-1 pipeline. Isolation valves were closed and the section of pipe was depressurized. There was no associated fire or explosion. A root cause analysis has determined the cause to be the failure of a girth weld in the form of a crack that originated at internal undercutting at the toe of the girth weld root pass and extending through the weld metal of the weld, also assisted by tensile axial stresses due to thermal stress at the low ambient temperature with no gas flow and bending stress at the sag bend.. The crack was likely produced during the initial welding process and ran from the 9 o'clock position to the 3 o'clock position around the pipe. The deficient weld was removed, new pipe installed, and the section has been placed back into service.
Year of pipe manufacture is assumed to be commensurate with year of installation

2/10/2015 - Part C - Type of incident changed from "Leak" to "Rupture".

3/27/2015 - Part E - Updated MAOP determination method to 192.619(a)(3).

7/20/2015 - Part A - Local time of incident revised from time of determination at 8:00 to time that TGP personnel heard hissing at 7:15 am. Time of telephonic report to the NRC revised from 9:15 to 10:12. Both revisions based upon input from PHMSA.

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Date	07/20/2015

Appendix D

Metallurgical Analysis

This document is on file at PHMSA

Appendix E

Root Cause Analysis

This document is on file at PHMSA