DOT	US Department of Transportation
PHMSA	Pipeline and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety
	Southern Region

Principal Investigator	Chris Taylor
Region Director	Wayne T. Lemoi
Date of Report	March 21, 2013
Subject	Failure Investigation Report – Tennessee Gas Pipeline Line 100-1, Batesville, Mississippi

Operator, Location, & Consequences

Date of Failure	11/22/2011
Commodity Released	Natural Gas
City/County & State	Batesville/Panola, Mississippi
OpID & Operator Name	19160 & Tennessee Gas Pipeline Company
Unit # & Unit Name	8762 & MS-3 (TGP District 63)
SMART Activity #	136736
Milepost / Location	Milepost 63-1+2.391/ 34.31776N, -90.04881W
Type of Failure	Rupture and fire due to failed repair sleeve installed over a wrinkle bend
Fatalities	None
Injuries	None
Description of area impacted	The pipeline ruptured and ignited the natural gas, creating a fireball that burned for several hours. The fire destroyed one wooden high voltage transmission tower owned by Entergy Mississippi. The explosion displaced large quantities of soil, creating a crater approximately 78 feet wide and 15 feet deep. The pipeline failure did not occur in a high consequence area (HCA).
Total Costs	$734,698

Executive Summary

On November 21, 2011, at approximately 8:15 p.m. Central Standard Time (CST), Tennessee Gas Pipeline Company (TGP) experienced a rupture on its Line 100-1 at Milepost 63-1+2.3988, which resulted in the release of natural gas. The line ruptured, as the result of a failed pressure containing repair sleeve, in a Class 1 location slightly downstream of TGP's Line 100-1 crossing with Levee Road, 1¾ miles north of U.S. Highway 278 (MS Highway 6), and approximately 7 miles west of Batesville, Mississippi.

The released natural gas ignited and burned for several hours. There were no reported injuries or fatalities; however, as a precaution, the local Panola County authorities evacuated approximately 20 nearby homes and rerouted traffic. Property damage was limited to displaced soil that created a large crater, exposed the pipeline, and incinerated one wooden high voltage transmission tower owned by Entergy Mississippi.

At approximately 8:45 p.m., TGP personnel responded to the rupture by activating the emergency shutdown device (ESD) of the Batesville Compressor Station (Station 63) to automatically stop the natural gas flow into and out of the compressor station. TGP personnel manually closed valves MLV 63-1D, 63-1BL, and 63-2BL to isolate Line 100-1 upstream of the leaking pipeline. TGP completed the isolation of the ruptured segment by shutting the downstream valves MLV-64-1 and MLV-64-2 at 9:20 p.m. and 9:30 p.m. respectively. At 10:03 p.m., TGP made a telephonic notification of this incident to the National Response Center (NRC). The NRC report number for this incident was 996191.

On November 22, 2011, the Pipeline and Hazardous Materials Safety Administration (PHMSA) Southern Region Office of Pipeline Safety dispatched an engineer to the incident location to investigate the pipeline failure. On November 28, 2011, PHMSA issued a Corrective Action Order (CAO)[1] to TGP as the result of this rupture, which required the operator to take immediate corrective actions on its Line 100-1. This included performing a metallurgical analysis, a root cause analysis, and a pipeline integrity verification on the pipeline segment affected by the failure defined by PHMSA in the CAO.

The metallurgical report indicated "*the* [Line 100-1] *failure consisted of a 57-inch long circumferential fracture in the body of the carrier pipe and a 61-inch long circumferential fracture in the body of the repair sleeve*"[2] and the subsequent root cause analysis indicated [Line 100-1] failed at this location due to a "*progressive buildup of stress*"[3] on a welded repair sleeve installed in 1946. The contributors to the stresses were the 1946 repair, vertical movement of the pipeline at this location, and external loads imparted on the repair sleeve. Based on these contributors, the root causes to the November 21, 2011, failure were determined to be the following:

- TGP had inadequate procedures for restoring proper support under Line 100-1 at the rupture location after an excavation in the year 2000;
- TGP failed to perform an engineering analysis of the repair once the pipeline was exposed after the excavation; and
- TGP gave inadequate guidance to its field personnel, through written procedures, to determine when engineering analysis may be required for repairs excavation.

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[1] PHMSA Compliance Progress File (CPF) No. 2-2011-1010H
[2] Excerpt from the El Paso Metallurgy Report, Conclusion #1
[3] TGP Root Cause Analysis, Section 6.1 Conclusions

System Details

At the time of the November 21, 2011, natural gas pipeline failure, the El Paso Corporation owned the Tennessee Gas Pipeline Company (TGP)[4] as well as the pipeline operators listed below, and it accounted for approximately 43,000 miles of natural gas pipelines across the United States:

- Tennessee Gas Pipeline Company
- Southern Natural Gas Company
- Colorado Interstate Gas Company
- Ruby Pipeline
- Wyoming Interstate Company
- El Paso Natural Gas Company
- Mojave Pipeline Company

TGP is a large, natural gas transmission pipeline system that generally extends from the southwest to the northeast United States (Appendix A, Figure 1). The system is divided into five pipelines designated as Line 100, Line 200, Line 300, Line 500, and Line 800.

The failure addressed in this report occurred on TGP's Line 100 pipeline, which begins in Texas and terminates in West Virginia. It is approximately 1,400 miles long and consists of four looped lines: Line 100-1, 100-2, 100-3, and 100-4.

The November 21, 2011, failure occurred on Line 100-1 at Milepost 63-1+2.3988 at a pressure-containing repair sleeve installed over a previously repaired wrinkle bend[5]. During the original construction in 1944, a crack developed in the center wrinkle of a three-wrinkle pipe bend (Appendix A). TGP repaired the crack with a repair-weld.[6] Additional reinforcement was provided by a 10-inch (axially) by 24-inch (circumferentially) metal patch welded over the repaired crack. In 1946, an additional crack developed in the same wrinkle, and TGP repaired it by installing a clamp over the leak and then enclosing the clamp with the pressure containing welded repair sleeve.

The welded repair sleeve had the following specifications:

- Longitudinal length: 15 inches
- Outside diameter: 31.8 inches
- Wall thickness: Approximately 0.50-inch
- Yield Strength: 49,700 psi (Note - TGP opines that the lower yield strength of the welded repair sleeve might have been lower than the carrier pipe (50,000 psi) due to the effects of the November 21, 2011 fire, assuming that the carrier pipe and repair sleeve materials were the same.)

The maximum allowable operating pressure (MAOP) of Line 100-1 at the failure location was 750 psig, and the operating pressure at the time of the failure was approximately 748 psig.

The failed carrier pipe section had the following specifications:

- Manufacturer and year: A.O. Smith, 1944
- Outside diameter: 24-inch
- Wall thickness: 0.250-inch
- Yield Strength: 50,000 psi
- Longitudinal seam: Electric Flash Welded (EFW)

[4] Kinder Morgan Energy Partners (KMEP) purchased El Paso Corp in 2011. KMEP fully integrated El Paso into its natural gas operations effective May 25, 2012

[5] The wrinkle bend was in an under-bend configuration (also known as a sag bend)

[6] Filling the crack with molten filler metal

- Coating: Coal tar enamel

TGP System Incident History

TGP experienced 3 incidents on its pipeline system within the 12 months immediately preceding the November 21, 2011, failure. The incidents are listed below in reverse chronological order:

- Line 200-4: On November 16, 2011, TGP's 36-inch diameter pipeline exploded and burned near Glouster, Ohio (Morgan County). The release and ignition produced a fireball that destroyed two homes and one other structure, damaged three other homes, and caused three injuries.
- Line 200-4: On February 10, 2011, TGP's 36-inch diameter pipeline failed at a cased road crossing, resulting in the release of natural gas and fire near Lisbon, Ohio (Columbiana County). There were no reported injuries or fatalities.
- Line 100-2: On November 30, 2010, TGP's 30-inch diameter pipeline failed in Natchitoches, Louisiana (Natchitoches Parish), resulting in the release of natural gas. There were no reported injuries or fatalities.

Events Leading up to the Failure

1. In 1944, during the original construction of Line 100-1, the center wrinkle of a three-wrinkle under-bend failed and formed a small crack. TGP repaired the crack with a repair-weld.
2. Two years later in 1946, due to additional pipe strain[7], Line 100-1 failed at the same location as the 1944 repair. TGP attempted to repair this failure with a repair weld as it had done previously but was unsuccessful. TGP then installed a leak clamp over the repair and a placed a full encirclement sleeve (welded repair sleeve) over the leak clamp to contain the natural gas. A 2-inch pipe nipple and valve were installed on the outside of the sleeve.
3. In 1999, TGP ran an inline inspection tool (ILI) through Line 100-1 and received a dent "call-out" in the area of the 1944 and 1946 repairs. In 2000, TGP excavated the area to investigate the call-out and discovered the repair sleeve, as well as two wrinkle bends and two river weights. During the excavation, TGP's excavation contractor struck the 2-inch pipe nipple (or valve) on the repair sleeve with a backhoe bucket and caused a gas leak. TGP replaced the nipple/valve assembly with a bull plug[8] (Appendix A, Figure 14) and continued to inspect the exposed wrinkle bends. TGP recoated and backfilled the pipeline.
4. At some point in the operational history of this pipeline prior to the sleeve failure, the carrier pipe experienced a through-wall crack in the fillet weld between the repair sleeve and the pipe.

It should also be noted that TGP hydrostatically pressure tested the Line 100-1 segment containing the repair sleeve five times and ran inline inspection tools two times over the life of the pipeline.

Emergency Response

On Monday November 21, 2011, at approximately 8:30 p.m. Central Standard Time (CST)[9], a TGP pipeline controller at the Batesville Compressor Station near Batesville, Mississippi, noticed a pressure

[7] The sources and magnitude of these pipe strains were postulated during the root cause analysis by TGP
[8] A "bull plug" is a threaded nipple with a rounded, closed end used to stop up a hole or close off the end of a pipeline.
[9] All times in this report are in Central Standard Time (CST)

drop from 748 psig to 710 psig on TGP's Line 100 system. Shortly afterward, a local resident called the TGP controller at the Batesville Compressor Station to report the sound of escaping gas.

At 8:41 p.m., a TGP employee en route to the scene witnessed a large fireball, which was the result of the igniting natural gas. The ignition source remains unknown. The ignited natural gas burned for several hours. Property damage was limited to displaced soil that created a large crater exposing the pipeline and one burned wooden electrical power transmission tower owned by Entergy Mississippi, Inc. (Appendix A, Figures 6-9)

At approximately 8:45 p.m., TGP personnel responded to the rupture by activating the emergency shutdown device (ESD) of the Batesville Compressor Station (Station 63) upstream of the leak location. This stopped the flow of natural gas into and out of the compressor station and isolated Line 100-1 upstream of the leak. TGP personnel blocked-in the leak by shutting the downstream valve on Line 100 (MLV-64-1) at 9:30 p.m. At 10:03 p.m., TGP made a telephonic notification to the National Response Center (NRC). The NRC report number for this incident was 996191 (Appendix B).

There were no reported injuries or fatalities; however, as a precaution, the local Panola County authorities evacuated approximately 20 nearby homes[10] and rerouted traffic[11]. The nearest house was approximately 1,600 ft. away from the pipeline failure.

Summary of Return-to-Service

On November 28, 2011, the PHMSA Office of Pipeline Safety issued a Corrective Action Order (CAO)[12] to TGP, requiring it to take corrective actions on the Line 100-1 pipeline system. PHMSA issued the CAO based on the following pipeline safety concerns:

- The Line 100 portion that failed was more than 60 years old;
- The construction and repairs to Line 100 occurred more than 20 years before the promulgation of the Federal minimum safety standards for natural gas pipeline systems; and
- At the time of the November 21, 2011, incident, the TGP pipeline system was the subject of on-going failure investigations by PHMSA's Central and Southwest Regions for recent natural gas pipeline explosions and/or fires (see *TGP System Incident History* above).

The CAO included 19 corrective actions (Appendix F). The return-to-service requirements were addressed in CAO Items 4, 5, and 6 as follows:

4. *TGP must not operate the isolated segment*[13] *until authorized to do so by the Director,* [PHMSA] *Southern Region.*
5. *Prior to resuming operation of the Isolated Segment, TGP must develop and submit a written restart plan for prior approval to the Director, OPS Southern Region, Pipeline and Hazardous Materials Safety Administration...The restart plan must include actions to confirm the integrity of the Isolated Section.*

[10] Nearest house was approximately 1,600 ft. away from the pipeline failure

[11] U.S. Highway 278 was closed for approximately one hour and Macedonia Road was closed until 8:00 am the next day

[12] PHMSA Compliance Progress File (CPF) No. 2-2011-1010H. When applicable, a CAO requires the pipeline operator to submit a pipeline restart plan to PHMSA for approval, prior to restarting the failed segment.

[13] The "Isolated Segment" was the 9.16-mile section of Line 100-1 that extends from the Batesville Compressor Station to MLV-64-1. This section of pipeline was removed from service immediately after the November 21, 2011 rupture.

6. *After receiving authorization from the Director to restart the Isolated Segment, the pressure must not exceed 598 psig at any point along the Affected Pipeline[14]. This pressure restriction will remain in effect until written approval to increase the pressure or return the pipeline to its pre-failure operating pressure is obtained from the Director...*

Pipeline Repair

On March 5, 2012, TGP began replacing approximately 980 feet of 24-inch pipe from station number 121+90 to 131+60. By replacing this length of pipe, TGP was able to remove 7 field wrinkle bends, 3 field miter bends, and increase the depth of cover of approximately 520 feet of shallow pipe within its right-of-way through cultivated fields.[15] The replacement pipe had the following specifications:

- Outside diameter: 24-inch
- Wall thickness: 0.343-inch (thicker wall than the original pipe)
- Grade: X-70

On March 22, 2012, TGP completed the hydrostatic pressure test of the replaced section of pipe, and on March 30, 2012, the Southern Region Director approved TGP's restart plan for the isolated segment. On April 20, 2012, TGP restarted the isolated segment to a pressure of 598 psig, which represented 80 percent of the pressure at this location prior to the failure.

Field Observations

On November 22, 2011, the PHMSA inspector arrived at the failure site and, accompanied by TGP personnel, observed Line 100-1 intact, with the exception of a failed welded repair sleeve. The repair sleeve, which failed at the 6 o'clock pipe position, was one of five features along this pipeline in the failure area. The additional features, including the failed repair sleeve, were as follows (upstream to downstream – see Appendix A, Figures 11 and 12):

- River weight
- Wrinkle bend in an under-bend configuration
- Failed welded repair sleeve
- Wrinkle bend in the under-bend configuration
- River weight

The high pressure natural gas escaping from the failed repair sleeve displaced the soil, formed a crater approximately 78 feet in diameter, and exposed approximately 40 feet of the 24-inch pipeline. The depth of cover at this location was approximately 12 feet.

Findings and Contributing Factors

TGP examined the incident from three key perspectives:

1) Metallurgically, to describe the apparent cause of the pipe rupture;
2) Root cause, to analyze cause(s) and/or events that led to the failure; and
3) Pipeline integrity, to determine if the conditions similar to those contributing to the failure existed elsewhere on the Line 100-1 pipeline system.

[14] The "Affected Pipeline" was an 89.4-mile portion of Line 100-1 that included the "Isolated Segment." It originally extended from the outlet of the Greenville Compressor Station to MLV 68-1 and passes through Washington, Sunflower, Tallahatchie, Panola, Lafayette, and Marshal Counties in Mississippi.
[15] From the CAO, Operator's Response, *Re: CPF No. 2-2011-1010H, Item 5 (Batesville)*, dated March 9, 2011

Metallurgical Lab Findings

The metallurgical analysis was performed by the El Paso Metallurgy Group at the El Paso Metallurgical Laboratory in Houston, Texas. The metallurgical analysis of the failed welded sleeve and carrier pipe confirmed the November 22, 2011, field observations that Line 100-1 failed at MP 63-1+2.3988 as a result of the failed welded repair sleeve. The metallurgical report indicated the failure occurred at the 6 o'clock position on the 24-inch carrier pipe's outside diameter (OD) and at the same clock position on the repair sleeve's inside surface. More specifically, "*Opposing chevron marks along the fracture surface on the carrier pipe pointed toward the 6 o'clock position. River marks or a "V" pattern emanated from the [carrier pipe] OD surface to the inside diameter (ID), indicating the [carrier pipe] OD as the origin of the failure*."[16]

Further analysis indicated the carrier pipe likely failed before the repair sleeve failed for two reasons:
1) The presence of dark corrosion products within a through-wall crack in the carrier pipe indicated the presence of an old crack; and
2) The laboratory's analysis of the shear lips between the carrier pipe and repair sleeve indicated there was a minimal shear lip[17] on the carrier pipe, while there was a presence of a larger, sharper, shear lip at the origin of the repair sleeve. The analysis did not indicate the time interval between the carrier pipe and repair sleeve failures.

The carrier pipe failed at this location due to *"cumulative bending and axial overload stresses"* that created through-wall cracks at the toe of the fillet weld's[18] heat-affected zone. Higher steel hardness was measured at the heat-affected zone compared to a lower average hardness measured at the repair sleeve, weld metal, and pipe base metal.

Root Cause Analysis Findings

Kiefner & Associates, Inc., in conjunction with TGP, facilitated and led the root cause analysis for the November 21, 2011, incident. According to the root cause analysis, the failure occurred as a result of the existence of the four factors below acting concurrently at the failure location.

The four factors[19] that contributed to the failure were as follows:

- The 1946 repair sleeve was designed for the pipeline's internal pressure only. It was not designed for the combined internal and external loads imparted on the pipe.
- A depth of cover at this location of approximately 12 feet imparted an external load on the pipe sag bend.
- The pipeline was given less than adequate backfill support following a TGP field excavation in the year 2000. This resulted in additional external loading at the rupture locations.
- There were thermal expansion/contraction loads due to high natural gas temperature from the upstream Batesville Compressor Station versus the relatively lower ambient temperatures during the time of the Line 100 pipeline construction. The high temperature range was measured between 120-130 degrees Fahrenheit, and the lower ambient temperature at the time of construction was an assumed 70 degrees Fahrenheit.

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[16] From the *Analysis* section of the TGP Metallurgy report, *TGPUS-0000127, (11/21/11/ Line 1 MLV 63 incident)*

[17] A shear lip is a narrow, slanting ridge (approximately 45^{o} angle to the applied stress) along the edge of a ductile metal fracture. Typical cup and cone fractures exhibit a shear lip.

[18] The fillet weld joining the welded sleeve and 24-inch pipe

[19] TGP refers to these as Primary Causal Factors in the root cause analysis report

The TGP actions that contributed to the failure were as follows:

- *"At the time of the excavation in the year 2000, TGP field personnel did not recognize that the combination of the large amount of soil in the overburden, the poor soil properties of the soil at that location, the stresses associated with the configuration of the piping at that the location, and the stresses associated with the variance between the temperature at the time of construction as compared with the normal operating temperatures represented a set of circumstances that warranted an engineering evaluation.*
- *The pipeline was likely backfilled in a manner and with soil that did not provide sufficient support for the pipe configuration at that location."*

Line 100-1 Integrity Verification

Pre-Failure Integrity Verification

After the original construction in 1944, TGP pressure tested the Line 100-1 segment that included the failure with natural gas to a pressure of 765 psig. The subsequent tests along this segment were hydrostatic tests, as described below. Additionally, TGP ran inline inspection tools through this segment on three occasions since its original construction, also as described below:

a. Hydrostatic Pressure Test History
    - Hydrostatic test in 1966 up to 1,000 psig for 24 hours
    - Hydrostatic test in 1967 of 1,042 psig for 24 hours
    - Hydrostatic test in 1989 of 1,017 psig for 1 hour
    - Hydrostatic spike test[20] in 2005 of 1,144 psig for 1 hour
    - Hydrostatic spike test in 2011 of 1,135 for 1 hour
b. In-line Inspection (ILI) History
    - In 1999, the pipe segment was subject to ILI testing using the TDW Kaliper tool and the Tuboscope magnetic flux leakage (MFL) tool.
    - In 2000, TGP excavated the failure location and visually inspected the pipeline for a possible dent, which was identified in the ILI feature list. TGP did not find a dent but instead found the welded repair sleeve. TGP subsequently backfilled the pipeline as discussed earlier.
    - In September 2011, TGP ran a MFL tool. The tool identified the field fabricated repair sleeve and the wrinkle in between the sleeve. No metal loss was identified in this area.

Post Failure Integrity Verification

TGP reviewed the ILI data from the ILI runs described above to locate additional weld sleeves along Line 100-1 and to verify the intended purpose of the sleeve installation. TGP reviewed its 2008 Tuboscope High Resolution Magnetic Flux Leakage (MFL) ILI data and its 2011 Rosen High Resolution MFL ILI data that covered the entire affected area and found 11 weld reinforcing sleeves along Line 100-1. A total of 10 sleeves were installed during the original construction.

TGP cross-referenced the ILI data with its pipeline drawings and other records and determined those locations along the Line 100-1 pipeline that contained the welded repair sleeves did not have similar, additional characteristics that existed at Milepost MP 63-1+2.3988 and contributed to the failure on November 21, 2011.

[20] A spike test is a hydrostatic pressure test in which the test-pressure-to-operating-pressure ratio significantly exceeds the minimum value of 1.25 required by federal regulations and the duration of which is considerably shorter than the minimum time of 8 hours also required by federal regulations.

TGP extended the review of the ILI data and ILI features to Lines 100-2, 100-3, and 100-4 along the 89.4-mile Affected Area and did not discover pipeline features or conditions similar to the one responsible for the pipeline failure of November 21, 2011.

Conclusion

The incident of November 21, 2011, occurred on TGP's Line 100-1 at a pressure-containing welded repair sleeve. The failure originated at a through-wall crack at the toe of the fillet weld joining the carrier pipe and the welded repair sleeve. The crack developed at this location due to external forces acting at the fillet weld's heat-affected zone.

The sources of the external forces were as follows:

- There was a depth of cover of 12 feet at this location.
- There was an inadequate original welded repair sleeve design. The welded repair sleeve, which was installed in 1946, was not designed for the loads experienced at this location over the life of the sleeve.
- There were higher operational temperatures compared to the installation temperature, which resulted in thermal expansion and contraction.
- There was improper backfill or low soil strength after TGP excavated at this location in 2000.

The root causes of this pipeline failure focus on the excavation that occurred in 2000. The root causes were determined to be the following:

- *There were inadequate procedures for restoring the proper support under the pipe following the excavation in 2000;*
- *There was inadequate guidance to field personnel to assist them in recognizing when a set of circumstances exists that requires an engineering analysis before proceeding with the repair; and*
- *There was a failure to obtain an engineering analysis of the appropriate repair to meet the varied circumstances.*

TGP confirmed through the Integrity Verification and Remediation Plan required by the CAO that the conditions that combined to create the failure environment at the welded repair sleeve that failed on November 21, 2011, do not exist at the locations of the other repair sleeves along the Line 100-1, 100-2, 100-3, and 100-4 pipelines, within the limits of the affected pipeline[21], as defined by the CAO.

[21] The "Affected Pipeline" was an 89.4-mile portion of Line 100-1 that included the "Isolated Segment." It originally extended from the outlet of the Greenville Compressor Station to MLV 68-1 and passes through Washington, Sunflower, Tallahatchie, Panola, Lafayette, and Marshal Counties in Mississippi.

Appendices

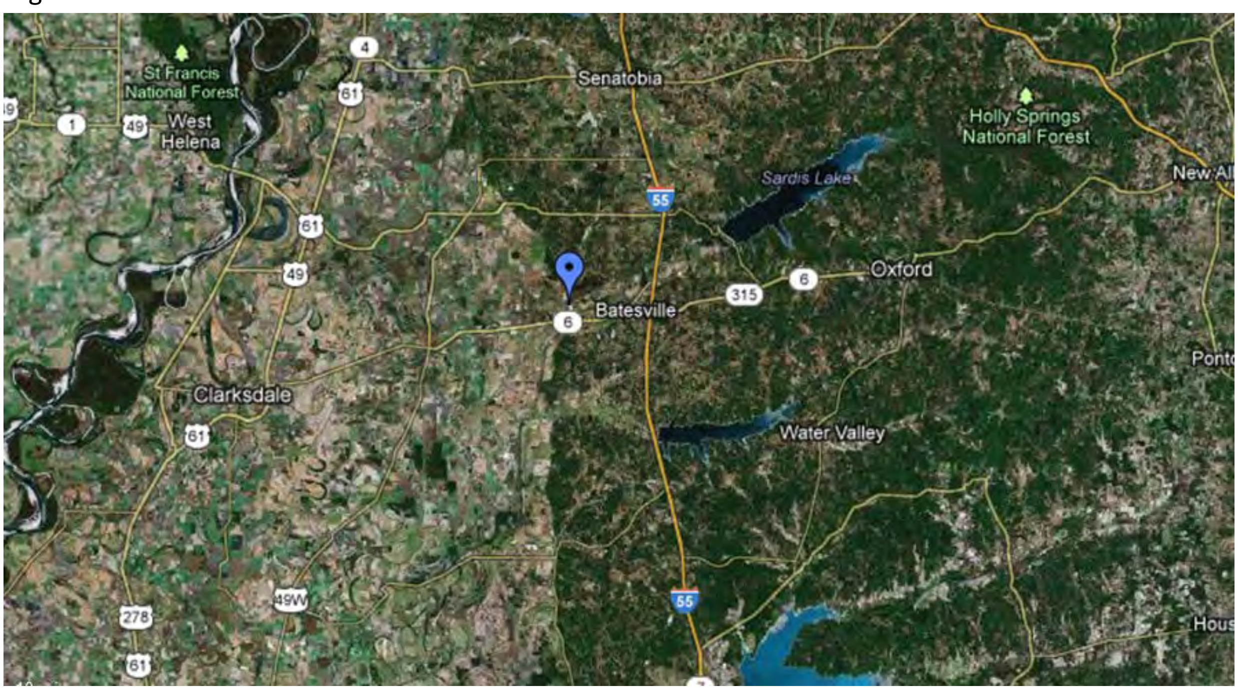
Map Redacted

These documents are on file at PHMSA

Appendix A Maps and Photographs

Figure 2. Blue Marker Indicates the TGP Line 100-1 Failure Location

Figure 3. Blue Marker Indicates the TGP Line 100-1 Failure Location



Appendix A Maps and Photographs

Figure 4. Failure Occurred North of US Highway 278/MS Highway 6

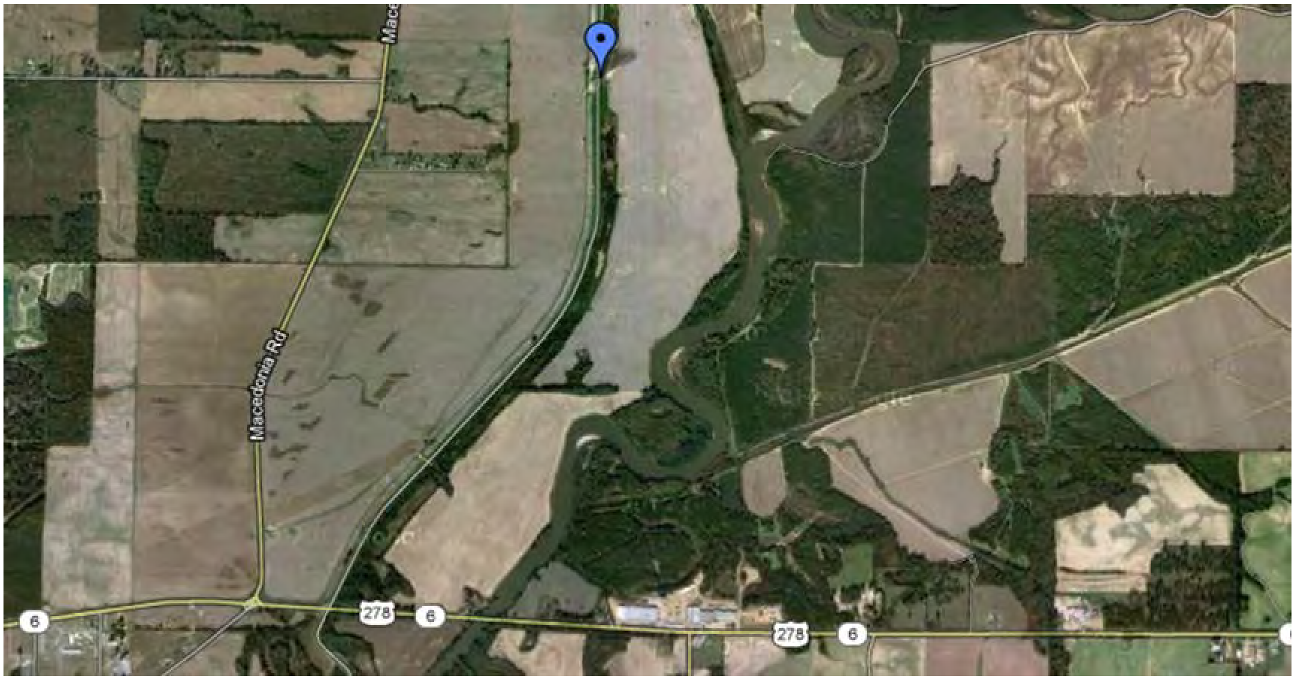


Figure 5. Blue Marker Indicates the Line 100-1 and Levee Road Crossing

Figure 6. The Line 100-1 rupture resulted in a 78-foot diameter crater. The ensuing fire burned a wooden high voltage tower owned by Entergy Mississippi (left of crater).

Figure 7. Burned wooden high voltage tower

Figure 8. West of crater – facing east is the Line 100-1 right-of-way direction

Figure 9. Closer view of the Line 100-1 pipeline within the crater facing east

Figure 10. Standing north of crater - gas flow from the Batesville Compressor Station was right to left (from approximate southwest to northeast). Batesville Compressor Station was approximately 2 miles upstream of the failure location.

Figure 11. Standing north of crater – Positioned right to left on the pipeline in this photograph, is a river weight, a pipe wrinkle (indistinct in this view) , a failed 1946 vintage welded repair sleeve, a pipe wrinkle (indistinct in this view), and a river weight.

Figure 12. Standing south of crater - Zoomed view of the failed 1946 field fabricated welded repair sleeve and adjacent wrinkle bends (gas flow from left to right).

Figure 13. Zoomed view of welded repair sleeve from south of crater, showing the 6 o'clock failure location. The carrier pipe failed at the same 6 o'clock position

Figure 14. Zoomed view of welded repair sleeve. The sleeve was installed over a barely visible leak clamp and a previously repaired failed wrinkle bend.
A 2-inch pipe nipple and bull plug are shown.

APPENDIX B

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 # 996191

INCIDENT DESCRIPTION

*Report taken at 23:03 on 21-NOV-11
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
The incident was discovered on 21-NOV-11 at 20:40 local time.
Affected Medium: AIR ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

XX

Type of Organization: UNKNOWN

INCIDENT LOCATION

SEE BELOW County: PANOLA
City: BATESVILLE State: MS
Section: 17 Township: 9S Range: 8W

RELEASED MATERIAL(S)

CHRIS Code: ONG Official Material Name: NATURAL GAS
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

CALLER IS REPORTING A RELEASE OF NATURAL GAS FROM A PIPELINE DUE TO UNKNOWN CAUSES. CALLER STATES THERE WERE EVACUATIONS BUT THE AMOUNT AND WHO WAS EVACUATED IS UNKNOWN AT THIS POINT.

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:	YES	Who Evacuated:		Radius/Area:			

Damages: NO

Closure Type		Description of Closure	Length of Closure	Direction of Closure	
Air:	N				
Road:	Y	HIGHWAY 6	2	E/W	Major Artery: Y
Waterway:	N				
Track:	N				

Passengers Transferred: NO

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

REMEDIAL ACTIONS

VALVE WAS SECURED.

Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: RAINY, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE

State/Local: EMA, FIRE AND POLICE DEPT.

State/Local On Scene: EMR, FIRE AND POLICE DEPT.
State Agency Number: NO REPORT#

NOTIFICATIONS BY NRC

CALCASIEU PARISH SHERIFF'S DEPT (CRIMINAL INTELLIGENCE UNIT)
21-NOV-11 23:13

USCG ICC (ICC ONI)
21-NOV-11 23:13

CGIS RAO ST. LOUIS (COMMAND CENTER)
21-NOV-11 23:13

DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
21-NOV-11 23:13

U.S. EPA IV (MAIN OFFICE)
21-NOV-11 23:16

USCG NATIONAL COMMAND CENTER (MAIN OFFICE)
21-NOV-11 23:16

JFO-LA (COMMAND CENTER)
21-NOV-11 23:13

MEMPHIS POLICE DEPT (COMMAND CENTER)
21-NOV-11 23:13

MS DEPARTMENT OF HEALTH (MAIN OFFICE)
21-NOV-11 23:13

NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
21-NOV-11 23:13

NOAA RPTS FOR MS (MAIN OFFICE)
21-NOV-11 23:13

NATIONAL RESPONSE CENTER HQ (MAIN OFFICE)
21-NOV-11 23:15

HOMELAND SEC COORDINATION CENTER (MAIN OFFICE)
21-NOV-11 23:13

PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
21-NOV-11 23:13

PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY WEEKDAYS (VERBAL))
21-NOV-11 23:15

SHELBY SHERIFF'S OFFICE (CRIMINAL INTELLIGENCE UNIT)
21-NOV-11 23:13

MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
21-NOV-11 23:13

STEVE SPURLIN EPAIV (MAIN OFFICE)
21-NOV-11 23:13

USCG DISTRICT 8 (MAIN OFFICE)
21-NOV-11 23:13

ADDITIONAL INFORMATION

CALLER HAD NO ADDITIONAL INFORMATION.

***** END INCIDENT REPORT # 996191 *****

APPENDIX B

The National Response Center is strictly an initial report taking agency and does not participate in the investigation or incident response. The NRC receives initial reporting information only and notifies Federal and State On-Scene Coordinators for response. The NRC does not verify nor does it take follow-on incident information. Verification of data and incident response is the sole responsibility of Federal/State On-Scene Coordinators. Data contained within the FOIA Web Database is initial information only. All reports provided via this server are for informational purposes only. Data to be used in legal proceedings must be obtained via written correspondence from the NRC.

APPENDIX C

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: 01/31/2014

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Report Date:**	12/15/2011
	No.	20110396 - 15546 (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. Public reporting for this collection of information is estimated to be approximately 10 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

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

PART A - KEY REPORT INFORMATION

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

Last Revision Date:	06/21/2012
1. Operator's OPS-issued Operator Identification Number (OPID):	19160
2. Name of Operator	TENNESSEE GAS PIPELINE CO (EL PASO)
3. Address of Operator:	
3a. Street Address	569 Brookwood Village
3b. City	BIRMINGHAM
3c. State	Alabama
3d. Zip Code:	35209
4. Local time *(24-hr clock)* and date of the Incident:	11/21/2011 20:14
5. Location of Incident:	
Latitude:	34.31776
Longitude:	-90.04881
6. National Response Center Report Number (if applicable):	996191
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	11/21/2011 22:00
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):	83,487.00
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?	Yes

- If No, Explain:	
- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	11/21/2011 21:30
15b. Local time pipeline/facility restarted	04/20/2012 18:00
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	Yes
17. Did the gas explode?	No
18. Number of general public evacuated:	71
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	11/21/2011 20:30
19b. Local time operator resources arrived on site	11/21/2011 20:45

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:	Mississippi
3. Zip Code:	38606
4. City	Batesville
5. County or Parish	Panola
6. Operator designated location	Milepost/Valve Station
Specify:	2.391
7. Pipeline/Facility name:	100-1
8. Segment name/ID:	63-1D
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):	120
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:	Repair Sleeve or Clamp
- If Pipe – Specify:	
3a. Nominal diameter of pipe (in):	
3b. Wall thickness (in):	
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	

3d. Pipe specification:	
3e. Pipe Seam – Specify:	
- If Other, Describe:	
3f. Pipe manufacturer:	
3g. Year of manufacture:	
3h. Pipeline coating type at point of Incident – Specify:	
- 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:	1944
5. Material involved in Incident:	Carbon Steel
- If Material other than Steel or Plastic – Specify:	
6. Type of Incident involved:	Leak
- If Mechanical Puncture – Specify Approx. size:	
Approx. size: in. (in axial) by	
in. (circumferential)	
- If Leak - Select Type:	Other
- If Other – Describe:	From under a weld sleeve.
- If Rupture - Select Orientation:	
- If Other – Describe:	
Approx. size: in. (widest opening):	
by in. (length circumferentially or axially):	
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. 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:	454
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	$ 1,000
7b. Estimated cost of Operator's property damage & repairs	$ 450,000
7c. Estimated cost of Operator's emergency response	$ 10,000
7d. Estimated other costs	$ 0
Describe:	
7e. Total estimated property damage (sum of above)	$ 461,000
Cost of Gas Released	
7f. Estimated cost of gas released unintentionally	$ 273,698
7g. Estimated cost of gas released during intentional and controlled blowdown	$ 0
7h. Total estimated cost of gas released (sum of 7.f & 7.g above)	$ 273,698

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	748.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	750.00
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. - 5f. below):*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Manual
5c. Length of segment isolated between valves (ft):	48,365
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?	SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations)
- 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 the following:	
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)*	Pressure at the time of the incident nor prior to the incident was not beyond normal operating limits.
- 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?	Yes
- If Yes:	
1a. Describe how many were tested:	4
1b. Describe how many failed:	0
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. Describe how many were tested:	
2b. Describe 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:	G4 - Other Outside Force Damage

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 High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the 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 Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage Due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in 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:	Other Outside Force Damage
- If Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation:	
- If Electrical Arcing from Other Equipment or Facility:	
- If Previous Mechanical Damage NOT Related to Excavation:	
Complete Questions 3-7 ONLY IF the "Item Involved in 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 **- If Intentional Damage:**	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	An existing sag condition in the pipeline under an unusually large depth of soil that imposed a high load stress on the sag condition, the pipeline being unable to withstand said load.

G5 – Material Failure of Pipe or Weld	**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
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-case selected below is based on the following *(select all that apply)*:	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe	
- Sub-cause is Tentative or Suspected; Still Under Investigation *(Supplemental Report required)*	
- If Construction-, Installation- or Fabrication- related:	
2. List contributing factors: *(select all that apply)*	
- If Fatigue or Vibration related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress	
- Other	
- If Other, Describe:	
- If Original Manufacturing-related (NOT girth weld or other welds formed in the field):	
2. List contributing factors: *(select all that apply)*	
- If Fatigue or Vibration related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	

APPENDIX C

3. Specify:	
- 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	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the 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?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the 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?	
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 Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Compressor), Vessel Plate, or other Material:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported 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 Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage:	

APPENDIX C

- If Underground Gas Storage, Pressure Vessel, or Cavern Allowed or Caused to Overpressure:	
1. Specify:	
- If Other, Describe:	
- If Valve Left or Placed in Wrong Position, but NOT Resulting in an Overpressure:	
- If Pipeline or Equipment Overpressured:	
- If Equipment Not Installed Properly:	
- If Wrong Equipment Specified or Installed:	
- 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

Tennessee Gas Pipeline (TGP) operations and gas control personnel noticed a pressure drop near Batesville Compressor Station (Station 63) near Batesville, MS, on November 21, 2011. Shortly thereafter, TGP was notified by a member of the general public about a leak just downstream of the compressor station. The gas ignited and although several homes were evacuated, no damage was incurred by the structures. The leak was isolated, the fire extinguished, with no injuries or fatalities. A root cause analysis was performed with the results now added to this report in Part G.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Date	06/21/2012

APPENDIX D

Required Corrective Action for Line 100-1
Corrective Action Order CPF No. 2-2011-1010H
Issued by PHMSA to TGP on November 28, 2011

1. The "Affected Pipeline" means the 89.4-mile portion of Line 100-1 that extends from the outlet of the Greenville Compressor Station (Station 54) to main line valve MLV 68-1.

2. The "Isolated Segment" means the 9.16-mile section of Line 100-1 that extends from the Batesville Compressor Station to MLV 64-1. The Isolated Segment is the portion of the Affected Pipeline that was removed from service immediately after the November 21, 2011 rupture and which must remain out of service until a restart plan is submitted and approved by the Director, Southern Region in accordance with Items 4 and 5.

3. The operating pressure along the Affected Pipeline must not exceed eighty percent (80%) of the actual operating pressure in effect immediately prior to the rupture (i.e., TGP will reduce, if required, and maintain a 20% pressure reduction in the operating pressure along the entire length of the Affected Pipeline). This pressure restriction will remain in effect until written approval to increase the pressure or return Line 100-1 to its pre-failure operating pressure is obtained from the Director pursuant to Item 17 or 18. By December 1, 2011, TGP must provide the Director with a list of the actual operating pressure at the Greenville and Batesville Compressor Stations on Line 100-1 at the time of failure, and the reduced discharge pressure settings at each compressor station.

4. TGP must not operate the Isolated Segment until authorized to do so by the Director, Southern Region.

5. Prior to resuming operation of the Isolated Segment, TGP must develop and submit a written re-start plan for prior approval to the Director, OPS Southern Region, Pipeline and Hazardous Materials Safety Administration, 233 Peachtree Street, Suite 600, Atlanta, GA 30303. The restart plan must include actions to confirm the integrity of the Isolated Section.

6. After receiving authorization from the Director to restart the Isolated Segment, the pressure must not exceed 598 PSIG at any point in the Affected Pipeline. This pressure restriction will remain in effect until written approval to increase the pressure or return the pipeline to its pre-failure operating pressure is obtained from the Director pursuant to Item 17 or 18.

7. Within 45 days of receipt of this Order, complete mechanical and metallurgical testing and failure analysis of the failed pipe, including analysis of soil samples and any foreign materials. Complete the testing and analysis as follows:
    A. Document the chain-of-custody when handling and transporting the failed pipe section(s) and other evidence from the failure site;
    B. Utilize the mechanical and metallurgical testing protocols, including the testing laboratory approved by the Director;

APPENDIX D

C. Prior to commencing the mechanical and metallurgical testing, provide the Director with the scheduled date, time, and location of the testing to allow a PHMSA representative to witness the testing; and
D. Ensure that the testing laboratory distributes all resulting reports in their entirety (including all media) whether draft or final, to the Director at the same time as they are made available to TGP.

8. Within 15 days following receipt of this Order, submit a report to the Director identifying any sections of the Affected Pipeline where any buildings intended for human occupancy are within the Potential Impact Radius (as defined in 49 C.P.R. § 192.903), all road and railway crossings, all High Consequence Areas (as provided in 49 C.P.R.§§ 192.903-192.905), and all Class 2, 3 and 4 locations.

9. Within 30 days of receipt ofthis Order, perform an aerial instrument or ground instrumented leakage survey of the Affected Pipeline. Investigate all leak indications and remedy all leaks discovered. Submit documentation of this survey to the Director within45 days of receipt of this Order.

10. Within 90 days following receipt of this Order, complete a failure root cause analysis (RCA) for the November 21, 2011 rupture, which is supplemented and facilitated by an independent third-party acceptable to the Director. Elements of the RCA must include but are not limited to: a scoping document of the RCA; procedures associated with the RCA; the methods used for the analysis and updates on each method as it progresses; and a study and analysis of environmental and other factors that may have caused stresses on the pipeline contributing to the failure. The RCA must document all contributory factors and the decision-making process. A final report of the RCA results must be submitted to the Director, including any lessons learned and whether the findings are applicable to other locations and pipelines within the TGP pipeline system.

11. Within 90 days of receipt of this Order, submit to the Director for approval an Integrity Verification and Remediation Plan (IVRP) to investigate, evaluate, and remediate the Line 100-1 pipeline. The IVRP will include, at a minimum, the following actions:

A. Identify all pipe in the Affected Pipeline with characteristics similar to the contributing factors identified for the November 21,2011 failure;
B. Perform an evaluation of the Affected Pipeline based on the findings of the mechanical and metallurgical study performed as required by Item 7 and of the RCA required by Item 10.
C. Determine if conditions similar to those contributing to the failure are likely to exist elsewhere on the Affected Pipeline;
D. Develop and implement an integrity testing plan. The integrity testing plan must address all factors known or suspected in the failure, including, but not limited to, internal inspection tool surveys, pressure testing, and remedial action. The type of internal inspection tools or other testing used must be technologically appropriate for assessing the system based on the types offailure(s) that occurred on November 21, 2011, with an emphasis on identifying and evaluating: 1) anomalies associated

with wrinkle bends repaired by sleeves and 2) dents, gouges, and grooves repaired by sleeves. Previous testing results may be used if approved by the Director.

E. Provide a detailed description of the inspection and repair criteria to be used in the field evaluation of the anomalies that are excavated, to include a description of how any defects are to be graded (if appropriate) and a schedule for repairs or replacement;

F. Remediate any pipe in the Affected Pipeline identified as having the potential to fail as soon as conditions permit, focusing on areas where there is a potential threat to life, property or the environment;

G. A process for extending the IVRP to the entire length of Line 100-1 and to Lines 100-2, 100-3, and 100-4 should the results of the evaluation, testing, and remediation indicate a potential systemic issue on the Line 100 System; and

H. Provide a proposed schedule for completion of the actions required by paragraphs (A) through (G) of this Item.

12. The IVRP will be incorporated into this Order. Revise the IVRP, as necessary, to incorporate the results of actions undertaken pursuant to this Order and whenever necessary to incorporate new information obtained during the failure investigation and remedial activities. Submit any such plan revisions to the Director for prior approval. The Director may approve plan elements incrementally.

13. Implement the IVRP as it is approved by the Director, including any revisions to the plan.

14. Submit quarterly reports to the Director that: (1) include all available data and results of the testing and evaluations required by this Order, and (2) describe the progress of the repairs or other remedial actions being undertaken. The first quarterly report for the period from November 21 through December 31, 2011, must be submitted by January 31, 2012. Each subsequent quarterly report must be submitted by the last day of the month following the last month of the quarter; e.g. April30, 2012, for the first quarter of2012, and July 31, 2012, for the second quarter of 2012.

15. Itis requested but not required that TGP maintain documentation of the costs associated with implementation of this Corrective Action Order. Include in each quarterly report submitted, the to-date total costs associated with: (1) preparation and revision of procedures, studies and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.

16. With respect to each submission that under this Order requires the approval of the Director, the Director may: (a) approve, in whole or part, the submission; (b) approve the submission on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove in whole or in part, the submission, directing that TOP modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, TOP must proceed to take all action required by the submission as approved or modified by the Director. If the Director disapproves all or any portion of the submission, TOP must correct all deficiencies within the time specified by the Director, and resubmit it for approval.

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17. The Director may allow the permanent removal of the pressure restriction set forth in Item 3 upon a written request from TOP demonstrating that the hazard has been abated and that restoring the pipeline to its pre-failure operating pressure is justified based on a reliable engineering analysis showing that the pressure increase is safe considering all known defects, anomalies and operating parameters of the pipeline.

18. The Director may allow the temporary removal or modification of the pressure restrictions set forth in Item 3 upon a written request from TOP demonstrating that temporary mitigative and preventive measures are implemented prior to and during the temporary removal or modification of the pressure restriction. The Director's determination will be based on the failure cause and provision of evidence that preventative mitigative actions taken by the operator provide for the safe operation of the pipeline segment during the temporary removal or modification of the pressure restriction. Appeals of determinations by the Director will be decided by the Associate Administrator for Pipeline Safety.

19. The Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted demonstrating good cause for an extension.

Appendix E and F

These documents are on file at PHMSA