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

Principal Investigators	Don Murphy, Derick Turner and Chris Taylor
Region Director	Wayne T. Lemoi
Date of Report	June 16, 2011
Subject	Failure Investigation Report – Southern Natural Gas, 2nd North Main Pipeline, Louisville, MS

Operator, Location, & Consequences

Date of Failure	January 6, 2010
Commodity Released	Natural Gas
City/County & State	Louisville/Winston County, Mississippi
OpID & Operator Name	18516, Southern Natural Gas
Unit # & Unit Name	1292, MS-2
SMART Activity #	128275
Milepost / Location	MP 50.642 of the 2nd North Main Line -five miles west of Louisville, Mississippi approximatetly 700 feet south of the intersection of Mississippi State Route (SR) 14 and Whitehall Road (33.10762N 89.15281W)
Type of Failure	External corrosion pitting with stress corrosion cracking as second failure mechanism.
Fatalities	0
Injuries	0
Description of area impacted	The incident occurred in a Class 2 location; no high consequence areas (HCAs) were affected. The El Paso metallurgical report and root cause analysis (written for Southern Natural Gas) incorrectly described the incident occuring in a Class 1 location.
Property Damage	The force of the rupture damaged an existing 3-inch PVC municipal water line serving a 20-house community south of the rupture location.

Executive Summary

On Wednesday, January 6, 2010, at approximately 4:26 am CST, an in-service pipeline rupture occurred on Southern Natural Gas' (SNG) 24-inch diameter, 2nd North Main Pipeline (Line) at MP 50.642 in Winston County, Mississippi, approximately 5 miles west of the town of Louisville, Mississippi. The rupture occurred on a pipeline segment approximatetly 700 feet south of the intersection of Mississippi State Route (SR) 14 and Whitehall Road (Appendix A).

SNG Gas Control observed a pressure drop on its SCADA system shortly after the Louisville Compressor Station received a notification from a local resident. SNG staff were dispatched and responded to the incident by closing the Center Ridge Gate valve (MP 45.683) at approximately 4:55 am CST (located immediately upstream of the rupture) and by closing the Louisville Compressor Station's valve number 6 (MP 55.997) at approximately 4:46 am CST (located immediately downstream of the rupture).

SNG notified the National Response Center (NRC) on January 6, 2010, at 5:27 am CST (6:27 am Eastern Standard Time on the NRC report). (Appendix B). There was no fire associated with the rupture, nor were there any fatalities or injuries; however, there was one self-evacuation of a household (2-3 people total) located approximately 600 feet north of the rupture.

The force of the rupture affected three pipe joints; one complete joint and two partial joints (one downstream and one upstream). Approximately 53 ft 4 in of pipe was expelled from the ground in six pieces.

The 24-inch 2nd North Main Line failed due to external corrosion with near-neutral pH stress corrosion cracking (SCC) as the secondary failure mechanism. The SCC was located in an area of the most severe corrosion.

System Details

Southern Natural Gas operates pipelines under the El Paso Pipeline Group (El Paso), which consists of several operating subsidiaries with approximately 42,000 miles of interstate natural gas transmission pipelines throughout the United States. The January 6, 2010, rupture occurred on SNG's 2nd North Main Line.

The SNG 2nd North Main Line is part of the SNG North Main Pipeline System, which is comprised of three parallel lines at the failure location:

- 22-inch North Main Line
- 24-inch North Main Loop
- 24-inch 2nd North Main Line (The January 6, 2010, rupture occurred on this pipeline)

The 2nd North Main line was installed in 1952-53, and is approximately 236 miles long with five sections capable of receiving and launching in-line inspection (ILI) and pipeline cleaning tools. The 2nd North Main line originates at the Pickens Compressor Station (MP 0.00) in Pickens, Holmes County, Mississippi, and traverses several Mississippi and Alabama counties before terminating at Rowe Gate (MP 236.745) near Lincoln, Talledega County, Alabama.

Natural gas can flow bidirectionally through certain sections of the 2nd North Main line due to natural gas injections into and withdrawals from the Muldon Gas Storage field located downstream of the Louisville Compressor Station in Monroe County Mississippi. The failure segment was located within this bidirectional section.

The maximum allowable operating pressure (MAOP) along this pipeline segment at the time of failure was 750 psig. SNG established the MAOP along this segment in accordance with 49 Code of Federal Regulations (CFR) §192.619(c), *Maximum Allowable Operating Pressure-Steel or Plastic Pipelines* (grandfathered). The pipeline was operating at 740 psig at the time of failure; 10 psig below its MAOP.

The failed 24-inch 2nd North Main line had the following specifications:

- Manufacturer and Year: Republic Steel manufactured in 1952
- Wall thickness: 0.25-inch
- Grade: X52
- Longitudinal seam: doubled submerged arc welded (DSAW)
- Coating: coal tar enamel

Events Leading Up to the Failure

Prior to the January 6, 2010, 2nd North Main line failure, SNG experienced two reportable incidents on the 2nd North Main pipeline and one reportable incident on the North Main Loop, in which corrosion and/or SCC was the failure mechanism. Additionally, SNG ran in-line inspection (ILI) tools that revealed possible anomalous conditions at the failure location.

Related Pipeline Failures

- January 14, 1994, at MP 39.17 on the 2nd North Main in Attala County, Mississippi.
- June 5, 1996, at MP 399.824 of the 24-inch North Main Loop in Heflin, Cleburne County, Alabama.
- December 21, 2007, at MP 193.3, in Fultondale, Jefferson County, Alabama (north of Birmingham)

In-line Inspections

- 2005 high resolution magnetic flux leakage (HRES MFL) and geometry tools identified the feature that failed January 6, 2010
- 2009 HRES MFL and geometry tools identified the feature that failed January 6, 2010

Emergency Response

SNG Gas Control observed a pressure drop on the SCADA system shortly after the Louisville Compressor Station received a notification from a local resident indicating a “loud noise from Highway 14.” SNG staff were dispatched and responded to the incident by closing the Center Ridge Gate valve (MP 45.683), located immediately upstream of the rupture, at approximately 4:55 am CST; and by closing Louisville Compressor Station’s valve number 6 (MP 55.997), located immediately downstream of the rupture, at approximately 4:46 am CST. SNG notified the National Response Center (NRC) on January 6, 2010, at 5:27 am CST (6:27 am Eastern Standard Time on the NRC report).

This event did not require any county or city emergency response because there was no fire associated with the rupture, nor were there fatalities or injuries. However, there was one self-evacuation of a household (2-3 people total) located approximately 600 feet north of the rupture.

Summary of Initial Start-Up Plan and Return-to-Service, Including Preliminary Safety Measures

PHMSA issued a Corrective Action Order (CAO) to SNG on January 13, 2010. The CAO was applied to the 56-mile pipeline segment between Pickens Compressor Station (MP 0.0) and Louisville Compressor Station (MP 55.997). Below is a condensed description of significant CAO requirements:

- Maintain 20% pressure reduction between the Pickens Compressor Station (MP 0.0) and the Louisville Compressor Station (Mile Post 55.997); specifically the operating pressure shall not exceed 592 psig when returned to service. Obtain written approval from PHMSA Southern Region before any pressure increase.
- Complete mechanical and metallurgical testing and failure analysis of the failed pipe within 30 days of receipt of CAO.
- Develop a return-to-service plan and submit it to the Director for prior approval, within 60 days of receipt of the CAO. The return-to-service plan must address incremental pressure increases and patrolling of the pipeline segment following each pressure increment. The return-to-service plan should specify a day-light restart and detail advance communications with local emergency response officials.
- Perform a root cause analysis to determine the cause of the failure, including a study and analysis of the Action Plan SNG implemented on the 2nd North Main Pipeline subsequent to the December 21, 2007incidnet, within 60 days of receipt of this CAO, with a report to follow within 90 days of receipt of this CAO.
- Develop and implement an Integrity Verification and Remediation Plan (IVRP) to assure the causal factors identified in the root cause analysis were used as integrity management program (IMP) inputs to improve the SNG IMP overall, and to help prevent similar pipeline failures in the future.

The rupture force expelled a total of 53 ft 4 in of pipe from the ground; SNG flame cut an additional 5 ft of pipe from both the upstream and downstream termini which was used for metallurgical sampling for a total of 63 ft 4 in. The complete repair required SNG to replace 100 feet of pipe. The replacement pipe specifications are as follows:

- Manufacturer and Year: Stupp in 2008
- Wall Thickness: 0.375-inch
- Grade: X70 API-5L
- Longitudinal seam: High frequency electric resistance welded (HF ERW)
- Coating: Fusion Bond Epoxy (FBE)

On January 15, 2010, SNG submitted a purge plan and a return-to-service plan to PHMSA for review and approval. PHMSA approved the plan with no additional recommendations. SNG purged the pipeline on January 19, 2010, and returned it to service with the 20% pressure reduction shortly afterwards.

Investigation Findings & Contributing Factors

The CAO required SNG to perform a root cause analysis to establish causal factors for the 2010 incident based on the 2nd North Main Line's operations and maintenance history, as well as the incident history over the operating life of the pipeline system. The reports required by the CAO were written under the SNG and El Paso cover and are referenced below as they were titled.

The El Paso Metallurgical Analysis for the January 6, 2010, Failure

The 24-in 2nd North Main Line failure was caused by a cluster of external corrosion pits with subsequent near-neutral pH stress corrosion cracking (SCC) confined within a localized area of the most severe corrosion.

External corrosion initiated this failure and allowed electrochemical corrosion to reduce the pipe wall, increasing the localized stresses. This crossed the threshold for SCC to initiate and propogate until the remaining pipe wall could no longer support the operating pressure of 740 psig and ruptured.

Previous SNG 2nd North Main Failures

SNG experienced two reportable incidents on the 2nd North Main pipeline and one reportable incident on the North Main Loop, in which external corrosion and/or SCC was the failure mechanism.

- On January 14, 1994, SNG experienced an in-service failure at MP 39.17 on the 2nd North Main in Attala County, Mississippi, approximately 12 miles upstream from the January 6, 2010, failure and within the same valve segment. Battelle investigated the failure and determined the cause was near-neutral pH SCC and corrosion fatigue associated with a dent and corrosion pitting.
- On June 5, 1996, SNG experienced an in-service failure at MP 399.824 of the 24-inch North Main Loop in Heflin, Cleburne County, Alabama. SNG investigated the failure and determined the cause was SCC. SNG determined the 1996 failure pipe had a microstructure more susceptible to SCC and similar to the microstructure of the January 1994 failed pipe.
- On December 21, 2007, SNG experienced an in-service failure at MP 193.3, in Fultondale, Jefferson County, Alabama (north of Birmingham). The El Paso Metallurgical Laboratory investigated the failure and determined the cause was external corrosion.

Integrity Management - Historical In-Line Inspections

SNG's integrity management program (IMP) threat analysis for high consequence areas (HCAs)within this pipeline segment identified external corrosion as a threat. Based on this threat, SNG used geometry and a high resolution magnetic flux leakage (HRES MFL) ILI as the IMP integrity assessment tools for this pipeline segment.

- A 2005 ILI identified the feature that failed on January 6, 2010, but defect clustering and reported depth, length, and the corresponding predicted failure pressure ratio of 1.55 times MAOP did not require SNG to complete an in-field investigation.
- A 2009 ILI also identified the feature that failed on January 6, 2010, but again defect clustering and reported depth, length, and corresponding predicted failure pressure ratio of 1.37 times MAOP did not require SNG to complete an in-field investigation.

A RUNCOM[1] analysis of the 2005 and 2009 inspections performed by the ILI vendor subsequent to the 2009 run indicated no statistical growth[2] which was the basis for SNG's decision not to field investigate the feature that failed on January 6, 2010.

Pressure Cycle Study and SCC

El Paso performed a pressure cycle study related to this incident and found the pressure cycles experienced by this pipeline were within industry norms for the natural gas transmission pipeline. The study also indicated pressure cycles alone do not initiate near-neutral pH SCC but could contribute to the growth once a crack is initiated. Based on the pressure cycle study, El Paso found the 2nd North Main line at the Louisville Compressor Station did not experience extreme pressure cycles. However, the pipe wall reduction due to external corrosion made the area more vulnerable the pressure cycle effects which had an influence on the SCC growth.

Conclusions

The *El Paso Root Cause Analysis Investigation Report*, written for the SNG 2nd North Main line failure, specified the following as causal factors contributing to the January 6, 2010, rupture.

1. External corrosion and subsequent pipe wall loss resulted from insufficient protection from the environment due to ineffective coating and inadequate cathodic protection on the pipe in the failure area.
2. Near neutral pH SCC contributed to the 2nd North Main failure as a secondary failure mechanism. The ideal conditions for near-neutral pH SCC existed in the failure area and are described below:
   a. Wall loss from the external corrosion described in paragraph 1 (above) resulted in localized elevated stress levels where the SCC was discovered
   b. Moist soil and ineffective coating
   c. The failure pipe material and microstructure was similar to pipe within the 2nd North Main line with a previous occurrence of near-neutral pH SCC
3. The ILI anomaly feature that eventually failed was identified in the 2005 and 2009 assessments, but this feature did meet the size and failure pressure ratio thresholds in either assessment to warrant an in-field investigation. The actual corrosion feature growth beween 2005 and 2009 was not large enough to warrant an in-field investigation

[1] RUNCOM is the trade name for the General Electric Company/PII Pipeline Solution's ILI run- comparison software used to analyze data from multiple inline pipe inspections.
[2] Corrosion growth exhibiting a greater than 5% change in reported depth according to RUNCOM.

References

1. El Paso/Southern Natural Gas, Root Cause Analysis Investigation Report, Southern Natural Gas 2nd North Main Line Mile Post 50.8, Winston County, Mississippi, April 7, 2010
2. El Paso Metallurgy Laboratory – Houston, Failure Analysis of SNG 2nd North Main Pipeline Rupture, February 12, 2010
3. Battelle, Investigation of Failure on Second North Main 24-Inch x 0.025-Inch X52 Pipeline, dated February 1994
4. Incident Report-Gas Transmission and Gathering Systems, SNG Incident of January 6, 2010, Report Number 20100002 – 15077, dated March 12, 2010
5. Incident Report-Gas Transmission and Gathering Systems, SNG Incident of December 21, 2007, Report Number 20080006 - 5316, dated January 17, 2008
6. Incident Report-Gas Transmission and Gathering Systems, SNG Incident of June 5, 1996, Report Number 19960101, dated July 3, 1996
7. Incident Report-Gas Transmission and Gathering Systems, SNG Incident of January 14, 1994, Report Number 19940027, dated February 4, 1994
8. PHMSA Corrective Action Order 2-2010-1002H issued to SNG January 13, 2010

Appendices

A Map and Photographs

B NRC Report Number

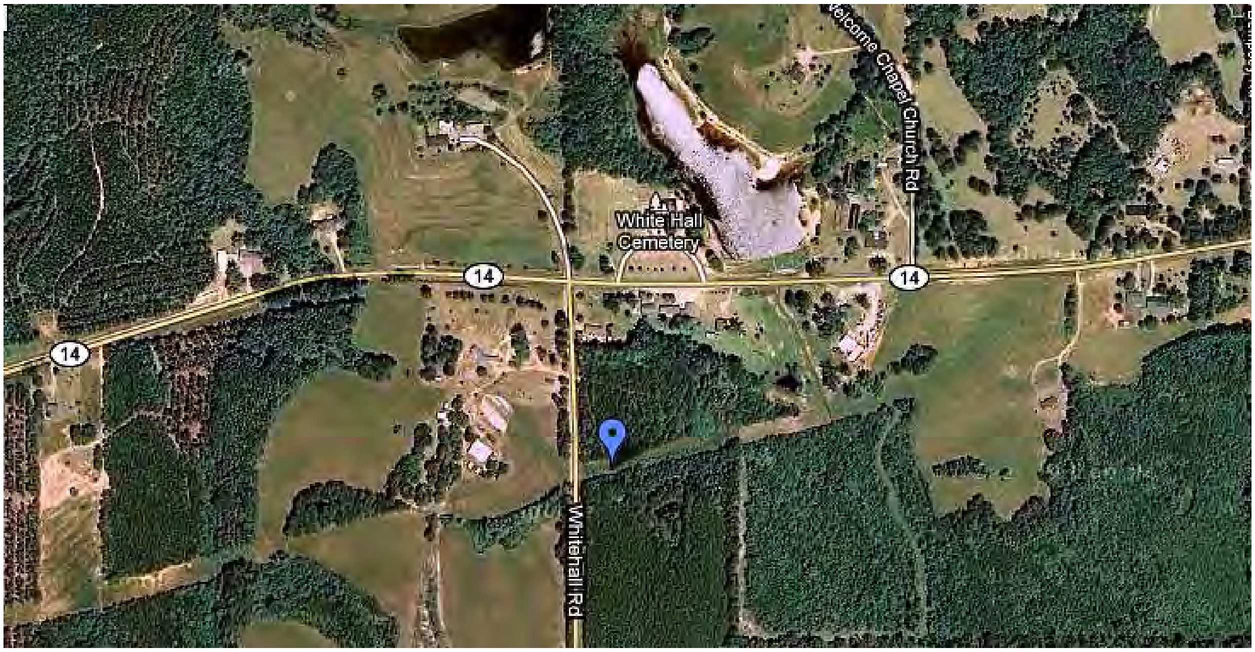
C Operator Incident Report to PHMSA

D Laboratory Analysis

Appendix A Maps and Photographs

Location Map 2nd North Main Line Rupture; blue marker indicates rupture location

Aerial view of 2nd North Main Line rupture location



2nd North Main Line upstream terminus

2nd North Main downstream terminus

Corrosion pitting in a section of expelled pipe

Corrosion pitting, same pipe section (zoomed-in)

Anomaly discovered on remaining downstream pipe section

Same anomaly from above, zoomed in and rotated 180^{o}

2nd North Main Line failure area getting prepared for repair

Welding of new replacement pipe

Incident Report # 927803

INCIDENT DESCRIPTION

*Report taken at 07:27 on 06-JAN-10
Incident Type: PIPELINE
Incident Cause: EQUIPMENT FAILURE
Affected Area:
The incident occurred on 06-JAN-10 at 04:26 local time.
Affected Medium: AIR   INTO THE AIR

SUSPECTED RESPONSIBLE PARTY

Organization: SOUTHERN NATURAL GAS
BIRMINGHAM, AL 35209

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

SEE LAT/LONG County: WINSTON
200 FEET SOUTH OF HWY 14
24 INCH SECOND NORTH MAIN PIPELINE
City: LOUISVILLE State: MS
Latitude: 33° 06' 37" N

Longitude: 089° 08' 20" 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 PIPELINE RUPTURED CAUSING A RELEASE OF AN UNKNOWN AMOUNT OF NATURAL GAS INTO 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:	YES	Who Evacuated:	PRIVATE CITIZENS	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 ISOLATED THE RUPTURE SITE AND THE LINE IS BEING BLOWN DOWN.

Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: CLEAR, 19ºF

ADDITIONAL AGENCIES NOTIFIED

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

NOTIFICATIONS BY NRC

USCG ICC (ICC ONI)
06-JAN-10 07:33
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
06-JAN-10 07:33
EPA OEM (MAIN OFFICE)
06-JAN-10 07:36
EPA OEM (AFTER HOURS SECONDARY)
06-JAN-10 07:36
U.S. EPA IV (MAIN OFFICE)
06-JAN-10 07:36
U.S. EPA IV (EPA RRT4)
06-JAN-10 07:33
FEDERAL EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
06-JAN-10 07:33
USCG NATIONAL COMMAND CENTER (MAIN OFFICE)
06-JAN-10 07:33
JFO-LA (COMMAND CENTER)
06-JAN-10 07:33
MEMPHIS POLICE DEPT (COMMAND CENTER)
06-JAN-10 07:33
MS DEPARTMENT OF HEALTH (MAIN OFFICE)
06-JAN-10 07:33
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
06-JAN-10 07:33
NOAA RPTS FOR MS (MAIN OFFICE)
06-JAN-10 07:33
NATIONAL RESPONSE CENTER HQ (MAIN OFFICE)
06-JAN-10 07:34
HOMELAND SEC COORDINATION CENTER (MAIN OFFICE)
06-JAN-10 07:33
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
06-JAN-10 07:33
MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
06-JAN-10 07:33

ADDITIONAL INFORMATION

THE CALLER HAD NO ADDITIONAL INFORMATION.

*** END INCIDENT REPORT # 927803 ***

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: 01/31/2013

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Report Date:**	03/12/2010
	No.	20100002 - 15077 (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.*

PART A - KEY REPORT INFORMATION

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

Last Revision Date:	09/17/2010
1. Operator's OPS-issued Operator Identification Number (OPID):	18516
2. Name of Operator	SOUTHERN NATURAL GAS CO
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:	01/06/2010 04:32
5. Location of Incident:	
Latitude:	33.10762
Longitude:	-89.15281
6. National Response Center Report Number (if applicable):	927803
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	01/06/2010 06:25
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):	41,176.00
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	01/06/2010 04:58
15b. Local time pipeline/facility restarted	01/20/2010 16:16
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	No
17. Did the gas explode?	No
18. Number of general public evacuated:	
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	01/06/2010 04:32
19b. Local time operator resources arrived on site	01/06/2010 04:44

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:	39339
4. City	Louisville
5. County or Parish	Winston
6. Operator designated location	Milepost/Valve Station
Specify:	50.785
7. Pipeline/Facility name:	2nd North Main
8. Segment name/ID:	Center Ridge Gate to Louisville
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):	60
12. Did Incident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
Name of body of water (If commonly known):	
Approx. water depth (ft) at the point of the Incident:	
Select:	
If Offshore:	
13. Approx. water depth (ft) at the point of the Incident:	
14. Origin of Incident:	
- If "In State waters":	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- If "On the Outer Continental Shelf (OCS)":	
- Area:	
- Block #:	
15. Area of Incident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility: - Interstate - Intrastate	Interstate
2. Part of system involved in Incident:	Onshore Pipeline, Including Valve Sites
3. Item involved in Incident:	Pipe
- If Pipe – Specify:	Pipe Body
3a. Nominal diameter of pipe (in):	24
3b. Wall thickness (in):	.25
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	52,000
3d. Pipe specification:	API 5L or equivalent
3e. Pipe Seam – Specify:	DSAW

- If Other, Describe:	
3f. Pipe manufacturer:	Republic
3g. Year of manufacture:	1952
3h. Pipeline coating type at point of Incident – Specify:	Coal Tar
- If Other, Describe:	
- If Weld, including heat-affected zone – Specify:	
- If Other, Describe:	
- If Valve – Specify:	
- If Mainline – Specify:	
- If Other, Describe:	
3i. Mainline valve manufacturer:	
3j. Year of manufacture:	
- If Other, Describe:	
4. Year item involved in Incident was installed:	1952
5. Material involved in Incident:	Carbon Steel
- If Material other than Steel or Plastic – Specify:	
6. Type of Incident involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
Approx. size: in. (in axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other – Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other – Describe:	
Approx. size: in. (widest opening):	75.4
by in. (length circumferentially or axially):	640
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Class Location of Incident:	Class 2 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 cost to Operator :	
7a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$ 4,000
7b. Estimated cost of gas released unintentionally	$ 242,699
7c. Estimated cost of gas released during intentional and controlled blowdown	$
7d. Estimated cost of Operator's property damage & repairs	$ 140,000
7e. Estimated cost of Operator's emergency response	$ 20,000
7f. Estimated other costs	$
Describe:	
7g. Estimated total costs (sum of above)	$ 406,699

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	740.00
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:	Manual
5b. Type of downstream valve used to initially isolate release source:	Manual
5c. Length of segment isolated between valves (ft):	54,458
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?	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 the following:	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)*	Low alarm and phone call from field personnel occurred simultaneously
- 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. Describe how many were tested:	
1b. Describe 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. 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:	G1 - Corrosion Failure
G1 - Corrosion Failure - *only one **sub-cause** can be picked from shaded left-hand column*	
Corrosion Failure – Sub-cause:	External Corrosion
- If External Corrosion:	
1. Results of visual examination:	General Corrosion
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	Yes
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other	Yes
- If Other – Describe:	Near neutral pH SCC as secondary failure mechanism.
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	Yes
- Determined by metallurgical analysis	Yes
- Other	
- If Other – Describe:	
4. Was the failed item buried under the ground?	Yes
- If Yes:	
4a. Was failed item considered to be under cathodic protection at the time of the incident?	Yes
- If Yes, Year protection started:	1963
4b. Was shielding, tenting, or disbonding of coating evident at the point of the incident?	No
4c. Has one or more Cathodic Protection Survey been conducted at the point of the incident?	Yes
If "Yes, CP Annual Survey" – Most recent year conducted:	2009
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	No
- If Internal Corrosion:	
6. Results of visual examination:	
- 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?	Yes
14a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage Tool	Yes
Most recent year run:	2009
- Ultrasonic	
Most recent year run:	
- Geometry	Yes
Most recent year run:	2009
- 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?	Yes
- If Yes,	
Most recent year tested:	1994
Test pressure (psig):	990.00
16. Has one or more Direct Assessment been conducted on this segment?	No
- If Yes, and an investigative dig was conducted at the point of the 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?	No
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:	
- 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:	
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:	
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:	
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:	
- 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

ON JANUARY 6 2010 SOUTHERN NATURAL GAS (SNG) COMPANY OPERATIONS PERSONNEL AT THE LOUISVILLE (MS) COMPRESSOR STATION ADVISED SNG GAS CONTROL THAT MEMBERS OF THE GENERAL PUBLIC HAD REPORTED A LOUD NOISE NEAR HIGHWAY 14 WEST OF LOUISVILLE MS. GAS CONTROL SAW A CORRESPONDING PRESSURE DROP VIA THE SCADA SYSTEM. A FAILURE HAD OCCURED ON SNG'S 24 INCH 2ND NORTH MAIN PIPELINE. SNG FIELD PERSONNEL WERE DISPATCHED TO CLOSE VALVES FOR ISOLATION OF THE FAILURE SITE AND TAKE THE AFFECTED SEGMENT OF PIPELINE OUT OF SERVICE. The failure was caused by a cluster of external corrosion pits with subsequent near-neutral pH stress corrosion cracking (SCC) confined within a localized area of the most severe corrosion. The evidence gathered during the investigation concluded that the external corrosion which initiated this failure allowed electrochemical corrosion to thin the pipe wall, increasing the localized stresses, which crossed the threshold for SCC to initiate and propagate until the remaining pipe wall could no longer support normal operating pressure.

File Full Name

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Appendix D Laboratory Analysis

This document is on file at PHMSA