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

Principal Investigators	Donald Murphy and Chris Taylor
Region Director	Wayne T. Lemoi
Date of Report	April 10, 2015
Subject	Failure Investigation Report—Columbia Gulf Transmission Company, Line 200 failure in Adair County, Kentucky

Operator, Location, & Consequences

Date of Failure	February 13, 2014
Commodity Released	Natural Gas
City/County & State	Knifley/Adair, Kentucky
OpID & Operator Name	2620 & Columbia Gulf Transmission Company
Unit # & Unit Name	8312 & KY-2
SMART Activity #	145783
Milepost/Location	Milepost 79.9 on Line 200; (b) (7)(F) [redacted]
Type of Failure	Pipeline rupture due to a hydrogen-assisted girth weld crack that failed due to external axial loading acting on the pipe. The most likely cause of the axial loading was land movement.
Fatalities	None
Injuries	Two
Description of area impacted	The incident occurred in a Class 2 non-High Consequence Area (non-HCA) location. The Columbia Gulf Transmission Company Line 200 is a 30-inch diameter natural gas transmission pipeline that ruptured, expelled pipe pieces, and created a crater approximately 105 feet long, 44 feet wide, and 25 feet deep. The rupture and ensuing fire burned two houses and damaged another. Three small buildings, one carport, and four cars were also damaged.
Total Costs	$1,800,013

Failure Investigation Report: Columbia Gulf Transmission Company, Line 200 Failure
Adair County, Kentucky
February 13, 2014

Executive Summary

On February 13, 2014, the Columbia Gulf Transmission Company (CGT) experienced a failure at Station 4164+02 on a pipeline named Line 200. Line 200 is a steel natural gas transmission pipeline 30 inches in diameter that runs near Knifley, Kentucky, a rural area located in Adair County, approximately 75 miles south-southeast of Louisville (Appendix A, Figures 1-3). It failed at an operating pressure of approximately 996 pounds per square inch gauge (psig), measured at the discharge of the CGT's Clementsville Compressor Station. The incident occurred between the CGT's Hartsville Compressor Station in Trousdale County, Tennessee, and its Clementsville Compressor Station in Adair County, Kentucky (Appendix A, Figure 4). The failure was a rupture that expelled several pieces of pipe as far as 380 feet from the centerline. The escaping natural gas ignited, destroying two nearby houses and damaging another house, three small buildings, one carport, four cars, and trees surrounding the rupture site.

In response to the rupture and ensuing fire, local authorities blocked a section of Kentucky Highway 76 and evacuated approximately 20 people from their homes while firefighters extinguished the fire and cleared the road. There were no fatalities, but there were two reported injuries that required medical attention. One person was treated for burns at a local hospital and released the same day, while the second person was admitted for observation before also being released the same day.

The CGT first became aware of the pipeline rupture at 2:03 a.m. Eastern Standard Time (EST)[1] on February 13, 2014, when an operations technician at the Clementsville Compressor Station observed a pressure drop on Line 200 from 966 psig to 460 psig. The operations technician, who had recorded Line 200's operating pressure as 965 psig just 3 minutes earlier, contacted the CGT's Gas Control in Charleston, West Virginia, to notify them of what appeared to be a pipeline failure. He also shut down Compressor [redacted] was compressing natural gas through Line 200 at that time. A review of the CGT's records indicated the complete shutdown of [redacted] occurred at 2:08 a.m.

The Office of Pipeline Safety of the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order (CAO) to the CGT on February 14, 2014, requiring the CGT undertake corrective actions on Line 200. The CGT contracted with the United States branch of Det Norske Veritas, Inc. (DNV), to complete the mechanical and metallurgical testing required by the CAO, as well as to supplement and facilitate the completion of a Root Cause Failure Analysis (RCFA), also required by the CAO. According to the DNV's metallurgical analysis, Line 200 failed due to axial loading at a hydrogen-assisted crack located in a girth weld. The metallurgical analysis stated that the likely source of the hydrogen was cellulosic welding rods used in 1965 during the pipeline's construction. It also stated that the likely source of the axial loading was land/soil movement, which was corroborated by geotechnical analyses and the RCFA.

The CGT contracted with Terracon Consultants, Inc. (Terracon), to collaborate on conducting additional geotechnical analyses on Line 200's right-of-way (ROW), which stretches from the Hartsville Compressor Station to the Leach Measurement Station. The geotechnical analyses were designed to detect signs of land movement, and the CGT and Terracon found a total of 35 locations along this stretch of pipeline ROW that showed signs of such movement. Terracon characterized these features as sinkholes or local subsidences, which their subsurface analysis indicated were the result of karst activity[2]. According to a

[1] All times in this report are Eastern Standard Time (EST) and are approximate.
[2] Karst describes topography produced by surface and subsurface water flow and dissolution of carbonate bedrock, leading to subsidence and/or collapse of the ground surface.

Karst map, the locations along the ROW and the area in which the February 13, 2014, failure occurred were prone to heavy and moderately heavy karst activity.

System Details

At the time of the incident, the CGT was owned by NiSource, Inc. (NiSource), an energy holding company headquartered in Merrillville, Indiana, that operated three distinct business segments: natural gas distribution, natural gas transmission and storage, and electric operations. After the failure, in late 2014, NiSource combined eight companies—including the CGT—to form the Columbia Pipeline Group. The Columbia Pipeline Group was a separate, publically traded company with foci including interstate natural gas transportation/storage and midstream services.

The CGT's natural gas pipeline transportation system originates along the Gulf Coast of the United States and travels through Louisiana, Mississippi, Tennessee, and Kentucky. The CGT pipeline system terminates approximately 3 miles south of Catlettsburg, Kentucky, at the Leach Measurement Station, where natural gas is transferred to Columbia Gas Transmission, another member of the Columbia Pipeline Group. The CGT pipeline system consists of three transmission pipelines:

- Line 100, which is 30 inches in outside diameter with a maximum allowable operating pressure (MAOP) of 935 psig
- Line 200, which is 30 inches in outside diameter with an MAOP of 1,008 psig
- Line 300, which is 36 inches in outside diameter with an MAOP of 1,008 psig

The CGT established the MAOP of Line 200 in 1965 by hydrostatically pressure testing a segment of approximately 13.5-miles (including the rupture location) at 1,472 psig for 8 hours.

The pipe in Line 200 that failed had the following specifications:

- Manufacturer and year: U.S. Steel Corporation, 1965
- Outside diameter: 30 inches
- Wall Thickness: 0.323 inches
- Specified Minimum Yield Strength (SMYS): 65,000 pounds per square inch (psi)
- Longitudinal seam type: Double-submerged arc weld (DSAW)
- Coating: Coal Tar Enamel (internally coated)

The rupture also affected a thicker-walled portion of pipe located at the north end of the rupture area. This pipe section transitioned from a wall thickness of 0.323 inches at the point of failure to a wall thickness of 0.438 inches before entering a casing underneath Kentucky State Hwy 76. The 34-inch-diameter casing underneath Kentucky State Hwy 76 was not affected by the rupture.

The thicker-walled pipe had the following specifications:

- Manufacturer and year: Republic Steel Company, 1965
- Outside diameter: 30 inches
- Wall Thickness: 0.438 inches
- SMYS: 60,000 psi
- Longitudinal seam type: DSAW
- Coating: Coal Tar Enamel (internally coated)

The CGT's Line 300 pipeline runs parallel to and is within 50 feet of Line 200 at the failure location. Line 100 is located approximately 1.4 miles east of Line 200.

Events Leading up to the Failure

Natural gas typically flows through the CGT pipeline system from the southwest to the northeast. At the time of the failure, however, the CGT had reversed the flow of natural gas in a relatively short section of Line 200 to supply gas to the Adair interconnect of the Texas Eastern Transmission Company (TETCO), which is located approximately 11.8 miles southwest of the Clementsville Compressor Station.

February 12, 2014 (the day before the failure)
Early in the morning of February 12, 2014, the CGT was operating Lines 100 and 200 between the Hartsville Compressor Station and the Clementsville Compressor Station at a common operating pressure. Line 300 was being operated independently.

At 8:40 a.m. the CGT started preparing Line 200 to reverse flow to transport natural gas in a southwesterly direction from the Clementsville Compressor Station to the TETCO Adair interconnect. To accomplish this the CGT closed [redacted] located approximately 13.9 miles southwest of the Clementsville Compressor Station, thereby isolating Line 200 between the valve and the station. The CGT also opened crossover valves to allow Line 200 to operate independently while keeping Lines 100 and 300 operating at a common pressure.

At 9:15 a.m. the CGT began delivering natural gas to the TETCO Adair interconnect from the compressor station by using [redacted] to move the gas in a southerly direction through Line 200. By 10:40 a.m. the delivery rate was 74 million standard cubic feet per day (MMSCF/day).

From noon until midnight, Line 200 operating pressure ranged from 900 to 966 psig.

February 13, 2014 (the day of the failure)
At 12:43 a.m. on February 13, 2014, the CGT began reducing the flow rate to the TETCO Adair interconnect; by 12:57 a.m. the flow rate had been reduced from 74 MMSCF/day to 25 MMSCF/day. Also, while the operating pressure on Line 200 had ranged from 900 psig to 966 psig, the operating pressure in this segment of Line 200 at the time of the rupture was approximately 966 psig.[3]

At 2:03 a.m. a CGT operations technician at the Clementsville Compressor Station left the office, where he had been monitoring compressor operations, to go on rounds within the compressor station. Upon leaving the office he noticed what appeared to be fire illuminating the sky south of the station, then returned to the office and observed a sharp drop in the pressure of Line 200. [redacted] records show occurred at 2:08 a.m. CGT personnel opened the blow-off valve at the Clementsville Compressor Station to help relieve the gas pressure and reduce the magnitude of the fire at the incident site within 40 minutes of the incident.

Emergency Response

Following the initiation of station shutdown, the operations technician called other Columbia Gulf operations personnel to respond to the event. They in turn contacted other appropriate personnel and contractors to respond to the incident and began isolating the incident area with assistance from the Control Room and Monitoring Center.

At 2:11 a.m. the operations technician closed [redacted] at the Clementsville Compressor Station to begin the isolation of Line 200.

---

[3] Measured at the discharge of the Clementsville Compressor Station.

By 2:40 a.m. the CGT personnel confirmed all of the appropriate valves at the (b) (7)(F) [redacted] were closed, locked, and tagged out and the TETCO Adair interconnect was equipped with a check valve to prevent the backflow of gas during the incident. These actions isolated the failed pipeline section.

At 6:00 a.m. the CGT personnel discovered that (b) (7)(F) [redacted] one of the valves used to isolate the incident location, was leaking natural gas. The CGT personnel closed (b) (7)(F) [redacted] to ensure complete isolation of the incident area, then blew down the line segment between the Clementsville Compressor Station (b) (7)(F) [redacted] 2, resulting in an isolated segment approximately 25.2 miles long.

In response to the rupture and fire, local authorities blocked a section of Kentucky Highway 76 and evacuated approximately 20 people from their homes while firefighters extinguished the fire and cleared the road. There were no fatalities, but there were two reported injuries that required medical attention. One person was treated at a local hospital for burns and was released the same day, while a second person was admitted for observation before also being released the same day.

The CGT personnel conducted foot patrols on Line 300 with leakage detection equipment hours after the rupture. They searched 1,000 feet both upstream and downstream of the rupture location, yet detected no leaks. The CGT personnel also performed an instrumented aerial leakage patrol with a helicopter that day to confirm the integrity of Lines 100, 200, and 300. The CGT did not detect any natural gas leaks.

The DNV—the contracted metallurgical and mechanical testing laboratory for the Line 200 pipeline failure—completed a pipeline interaction analysis on February 14, 2014, that concluded the Line 200 rupture did not impact the integrity of Line 300.

Requirements for Return to Full Service

On February 14, 2014, one day after the rupture, PHMSA's Office of Pipeline Safety issued a CAO, Number CPF 2-2014-1001H, to the CGT. This CAO required the CGT to address immediate and long-term safety and integrity concerns along Line 200[4] before returning the pipeline to full service. Such actions included—but were not limited to—mechanical and metallurgical testing, an RCFA, an approved written Restart Plan, the development and implementation of an Integrity Verification and Remediation Plan (IVRP), and a CAO Documentation Report. The CAO designated approximately 254 miles of Line 200, stretching from the Hartsville Compressor Station in Trousdale County, Tennessee, to the Leach Measurement Station in Boyd County, Kentucky, as the Affected Segment[5] and required the CGT take immediate and long-term corrective actions on this segment. The CAO is contained in Appendix B.

---

[4] While the Required Corrective Actions in the CAO apply to Line 200, the CAO also required the CGT to apply lessons learned from the investigative work done on Line 200 to its entire pipeline system.

[5] The CAO defined three terms that are used in this report as follows:

- Affected Segment means around 254.35 miles of the CGT's 30-inch Line 200 from the Hartville Compressor Station in Tennessee to the Leach Meter Station approximately 3 miles south of Catlettsburg, Kentucky.
- The Isolated Segment means the 25.20-mile segment of the CGT's 30-inch Line 200 from (b) (7)(F) [redacted] at Station 3294+56 to a block valve on the discharge side of the Clementsville Compressor Station at Station 4625+30. This is the portion of the Affected Segment that was shut-in after the failure on February 13, 2014, and that must remain shut-in until a restart plan is approved by the Director.
- The Director means the Director of PHMSA's Office of Pipeline Safety, Southern Region. The Director's address is 233 Peachtree Street, Suite 600, Atlanta, GA 30303.

The rupture occurred within the Affected Segment between [redacted] located on the property of the CGT's [redacted] located approximately 25.2 miles southwest of the station. The CGT closed these valves as part of its emergency response to stop the flow of natural gas into the rupture area and to isolate the pipeline segment. Accordingly, the CAO designated this 25.2-mile pipeline segment as the Isolated Segment.

To address immediate safety concerns along Line 200 and nearby Line 300, the CAO required the CGT to execute the following:

1) Refrain from operating the 25.2-mile Isolated Segment until authorized to do so by the Director.
2) Develop and submit to the Director for approval a written Restart Plan prior to resuming operation of the Isolated Segment.
3) Reduce by 20 percent and maintain the operating pressure of the Affected Segment with the understanding that the reduced pressure may not be increased (either temporarily or permanently) without written approval from the Director.

PHMSA did not impose a pressure restriction on the CGT's Line 300 because this pipeline was unaffected by the Line 200 rupture, as confirmed by a pipeline interaction analysis conducted by the DNV on February 14, 2014. Line 100 is located approximately 1.4 miles east of Line 200's rupture location and was not part of this analysis.

Investigation Details

The Line 200 rupture occurred on a moderately sloped hillside in a non-HCA, Class 2 location. The resulting crater measured approximately 105 feet long and 44 feet wide, with a depth varying from 13 to 25 feet deep. The pipeline cover (i.e. the ground surface on top of the pipe) measured approximately 4.7 feet on the southern side of the rupture site and approximately 8.5 feet on the northern side of the rupture site. There was approximately 80 feet between the open ends of the remaining pipe at the rupture location. The northern side pipe terminus appeared to be a fracture at a girth weld encircling approximately half of the circumference of the pipe, while the southern side pipe terminus exhibited an uneven appearance, indicating that the adjoining pipe was torn from that location. The rupture ejected a total of five pipe fragments, described below:

1) A large pipe section measuring around 44 feet in length was found on the opposite side of Route 76 in the right-of-way of Line 200, approximately 200 feet east of the center of the rupture location. This pipe section was fractured on both ends, with an intact pipe section approximately 20 feet long near its center (Appendix A, Figure 12).
2) A small pipe fragment around 2 feet in length was found approximately 380 feet north of center of the rupture location (Appendix A, Figure 13).
3) A pipe section measuring around 31 feet in length was found approximately 140 feet south of the center of the rupture location (Appendix A, Figure 14).
4) A pipe section measuring approximately 6 feet in length was found in a wooded area on the opposite side of State Route 76, approximately 310 feet east of the rupture location (Appendix A Figure 15).

5) A small pipe fragment measuring approximately 2 feet in length was found on the opposite side of State Route 76, approximately 160 feet east of the rupture location (Appendix A, Figure 16).

Metallurgical Analysis

The CGT contracted the DNV to perform a metallurgical/failure analysis using detailed protocols that incorporated PHMSA's requirements. The DNV's personnel arrived at the rupture site on February 13, 2014, located each expelled pipe section, and recommended to the CGT that the lengths of pipe beyond the north and south pipe termini[6] should be removed for mechanical and metallurgical analysis. The DNV personnel oversaw the staging and protection of these pipe sections, and all materials were ready for transfer to the DNV laboratory in Dublin, Ohio, by February 17, 2014.

On March 31, 2014, the DNV published its mechanical and metallurgical failure analysis entitled, "Final Report, Metallurgical Analysis Report of 30-Inch Diameter ML-200 Pipeline Service Failure," which can be found in Appendix C. The highlights of the DNV's findings are detailed below:

- The metallurgical analysis indicated the presence of a preexisting girth weld crack;
- The preexisting girth weld crack was hydrogen-assisted;
- The hydrogen was likely introduced into the crack during the welding process of Line 200's construction in 1965;
- There was no evidence of in-service fatigue growth of the crack;
- The crack failed due to high tensile axial stress acting on the girth weld; and
- The stress acting on the girth weld was from a large external load such as land/soil movement.

After the DNV issued its report, the CGT requested for additional magnetic particle testing to be performed on the girth welds of pipe fragments involved in this pipeline failure, which had not been previously tested for the presence of cracks. The DNV tested these additional girth welds and found no cracks.

Based on the results of its metallurgical analysis, the DNV concluded that external tensile axial loading acting on the pipe was the primary cause of the incident. They also stated that the origin of the pipeline failure was located at the hydrogen-assisted girth weld crack because this was the weakest location that carried the load from external forces.

Root Cause Analysis

The CGT's RCFA, entitled, "Columbia Gulf Transmission LLC Line 200 Adair County, Kentucky May 8, 2014," determined the following with support from the previously discussed metallurgical analysis:

- The primary cause of the failure was excessive external axial loading acting on the pipe;
- The external loading acted on the weakest location carrying the load, which was a girth weld with a hydrogen-assisted crack;
- The hydrogen was likely introduced into the girth weld during initial construction in 1965;
- Land movement was the most probable cause of external loading leading to the pipeline failure and rupture, although the data to definitively support ground movement was not recoverable given site disturbance during the incident; and
- The CGT noted evidence of potential unauthorized third-party crossing of the pipeline in the incident area; they considered it unlikely that heavy equipment crossing the pipeline could have caused the external loading leading to Line 200's failure, but did not rule it out completely.

[6] The portions of Line 200 pipe not affected by the rupture or fire.

Geotechnical Analysis

The CGT contracted with Terracon to perform geotechnical analyses in support of the failure investigation and to support the CGT's IVRP[7] for Line 200.

On February 15, 2014, a Terracon representative visited the pipeline failure site to perform an initial visual site assessment of the Line 200 post-incident ground surface and pipeline trench conditions for indicators of ground movement. Terracon reported the results of this initial failure site investigation in its report entitled, "Visual Site Assessment—Geotechnical Opinion Letter," dated March 31, 2014. In Section 3.0—Geotechnical Opinion Regarding Possible Ground Movement, Terracon stated, "[b]ased solely on visual assessment of the post-incident site conditions, we were not able to confirm or refute whether ground movement had occurred as a precursor to the incident because the data needed to definitively support ground movement was not recoverable given the level of site disturbance undergone during the incident." In Section 3.3—Site Ground Movement of the same report, however, Terracon asserted, "it is possible that conditions existed at the site that could have exerted an external force on the pipe, which are no longer observable post incident."

Terracon performed subsequent geotechnical investigations and analyses on Line 200 to assist the CGT in meeting the conditions of the Restart Plan[8] and the IVRP for the Isolated and Affected Segments. Specifically, the CGT's objective from a geotechnical perspective was to determine if conditions similar to those that caused the pipeline failure in Adair County, Kentucky, on February 13, 2014, existed in other areas along the Affected Segment or along Lines 100 and 300 within the same pipeline boundaries as the Affected Segment. To meet this objective, Terracon conducted a Geotechnical and Right of Way Use Survey over the Isolated Segment (initially) and the Affected Segment, following up on each survey with site investigations and, in some locations, remediations.

Isolated Segment Geotechnical and Right of Way Use Survey

The CGT and Terracon conducted low-altitude aerial surveys via helicopter over the pipeline ROWs for Lines 100, 200, and 300 between the (b) (7)(F) [redacted] (i.e. the Isolated Segment). The purpose of the aerial survey was to identify areas of potential ground movement and unauthorized third-party activities on the pipeline ROW. During the aerial survey, the CGT and Terracon observed a total of nine potential ground movement sites along the 25.2 miles of pipeline ROW. Terracon described each ground movement location as a "depression" or a "possible depression." After individual site visits to each of the nine locations, Terracon determined the following:

- Eight of the nine depression sites were related to karst activity;
- One location identified as a possible depression was determined to be bare soil and not related to karst activity;
- Five of the eight depressions did not pose an "immediate or significant potential threat to the [CGT] mainline pipelines;"
- The three remaining depressions that Terracon categorized as "localized subsidence or sinkholes," were located within the pipeline ROW and subjected to further geotechnical assessment and remediation; and
- During the remediation of these three sinkhole sites, the CGT personnel discovered one additional sinkhole and a property owner notified the CGT personnel of another sinkhole site,

[7] Condition 13 of the CAO, CPF 2-2014-1001H, issued to the CGT on February 14, 2014.
[8] Condition 3 of the CAO, CPF 2-2014-1001H, issued to the CGT on February 14, 2014.

bringing the total of locations found along the Isolated Segment that exhibited signs of possible ground movement due to karst activity to five.

In terms of tracking unauthorized third-party activities on the ROW, the CGT and Terracon observed 16 occurrences of possible third-party crossings along the Isolated Segment. The CGT had prior knowledge of 15 occurrences; the single occurrence of which it was not aware was an unauthorized bulldozer crossing and ditch work. The Terracon report dated July 17, 2014, entitled, "Pipeline Right-of-Way Aerial Survey and Visual Assessment of Areas of Interest ML100, 200, and 300—(b) (7)(F) [redacted] Columbia, Adair County, KY to Liberty, Casey County, KY," stated that the unauthorized crossing and ditch work had the potential to cause possible erosion along the Line 100/200/300 ROW. The CGT located and probed all three pipelines, as well as contacting the land owner and contractor performing the unauthorized work to discuss methods of repairing the ROW.

Affected Segment Geotechnical and Right of Way Use Survey

The CGT and Terracon conducted low-altitude aerial surveys in a helicopter over the pipeline ROW for Lines 100, 200, and 300 between the Stanton Compressor Station and the Leach Measurement Station, the Hartsville Compressor Station and Clementsville Compressor Station (excluding the Isolated Segment), and the Clementsville Compressor Station and Stanton Compressor Station. The purpose of the aerial survey was to identify areas of potential ground movement or unauthorized third-party activities on the pipeline ROW.

During the aerial survey, Terracon observed 24 apparent surface depressions within or near the pipeline ROW that it categorized primarily as "depressions" or "closed depressions" in its report entitled, "Pipeline Right-of-Way Aerial Survey and Visual Assessment of Areas of Interest (AOIs) Mainline ML100, ML200, and ML300 Pipeline Right-of-Way (ROW) Hartsville, TN Compressor Station to Leach Measuring Station in Catlettsburg, KY," dated December 22, 2014.

Terracon completed detailed visual site assessments of the 24 observed surface depressions and determined that none of the sites required immediate remediation, although it recommended that 6 be further evaluated. The CGT included these six locations in its Long Term Integrity Assessment & Reassessment Plan and will follow Terracon's recommendations with respect to the inspection, study, monitoring, or remediation of these sites. In addition to the six sites, Terracon recommended several of the remaining locations situated in a karst-prone area undergo periodic monitoring.

In terms of tracking unauthorized third-party activities on the ROW, Terracon and the CGT observed 13 occurrences of possible third-party crossings from Hartsville Compressor Station to Leach Measurement Station. The CGT had prior knowledge of nine instances; the four of which it was unaware are detailed below, with the CGT's actions shown in *italics*:

- One new structure adjacent to the ROW
  - *The CGT updated its geographic information system (GIS) to show the structure.*
- One downed pipeline marker
  - *The CGT personnel replaced the pipeline marker.*
- One unauthorized logging operation (loading of trucks within the ROW)
  - *The CGT had authorized limited logging operations on the ROW but also advised that no loading operations were to be performed within the pipeline ROW. The CGT personnel observed truck loading within the pipeline ROW during a follow-up visit the same day and stopped all logging operations.*
- One new residential structure was built adjacent to the ROW
  - *The CGT updated its GIS to show the structure.*

Terracon plotted each location identified during the Isolated Segment and Affected Segment Geotechnical and Right of Way Use Surveys on a Karst Occurrence in Kentucky map (Karst Map)[9] (Appendix D), and determined that all 24 locations identified along the Affected Segment and all 9 locations identified along the Isolated Segment were generally located within areas represented on the Karst Map as "moderate to highly karst prone areas."

Findings and Contributing Factors

Aside from rapidly occurring geological and geotechnical hazards like landslides (slope failures), earthquakes, or ground subsidence, the concept of land movement as a cause of pipeline failure can be difficult to substantiate due to its apparent latency.

Terracon conducted the Geotechnical and Right of Way Use Surveys on the Affected Segment and Isolated Segment to examine the CGT pipeline ROW for surficial signs of land movement. Terracon's identification of depressions along the CGT pipeline ROW from the Hartsville Compressor Station to the Leach Measurement Station—as well as the information obtained from the follow-up site visits, site excavations, and remediations—became supporting evidence for the root cause determination that land movement was the most probable source of the external loading on Line 200 that resulted in pipeline failure and rupture.

The PHMSA karst map (Appendix A, Figure 17) shows the Line 200 pipeline failure location relative to an area with a moderate potential for karst development. This map further illustrates this area's predisposition to land movement.

Appendices

A	Map and Photographs
B	Copy of Compliance Action Order, CPF No. 2-2014-1001H
C	DNV GL Metallurgical Analysis of the Line 200 Failure
D	Karst Occurrence in Kentucky map
E	NRC Report
F	Operator Incident Report to PHMSA (Form PHMSA F 7100.2)

[9] The Karst Occurrence in Kentucky map shows the relative potential for karst activity across the State of Kentucky. The map classifies the karst potentials as: limited to no potential for karst development, moderate potential for karst development, and high potential for karst development.

Appendix A Maps and Photographs

Figure 1. Blue marker indicates the pipeline failure location

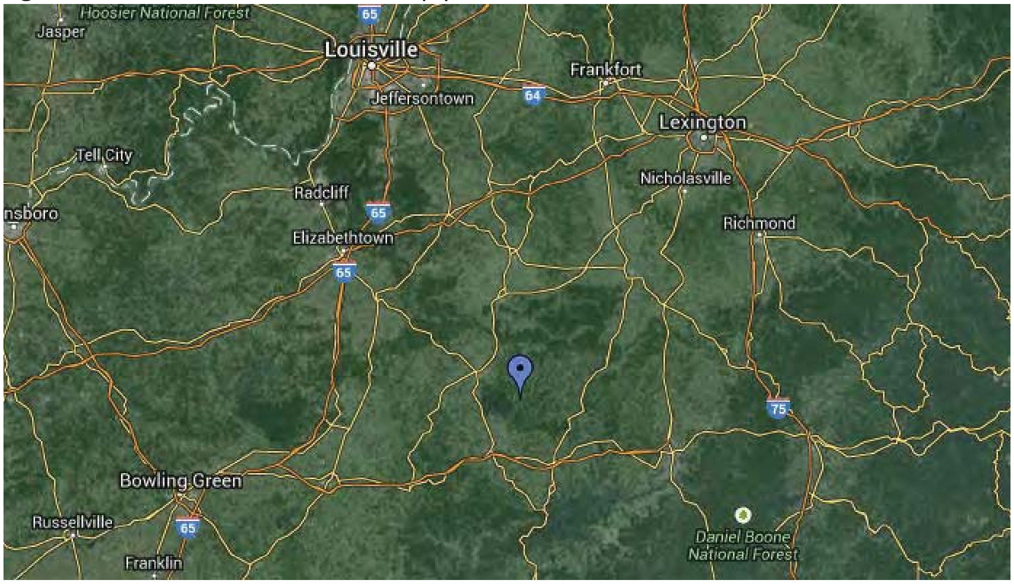


Figure 2. Blue marker indicates the pipeline failure location

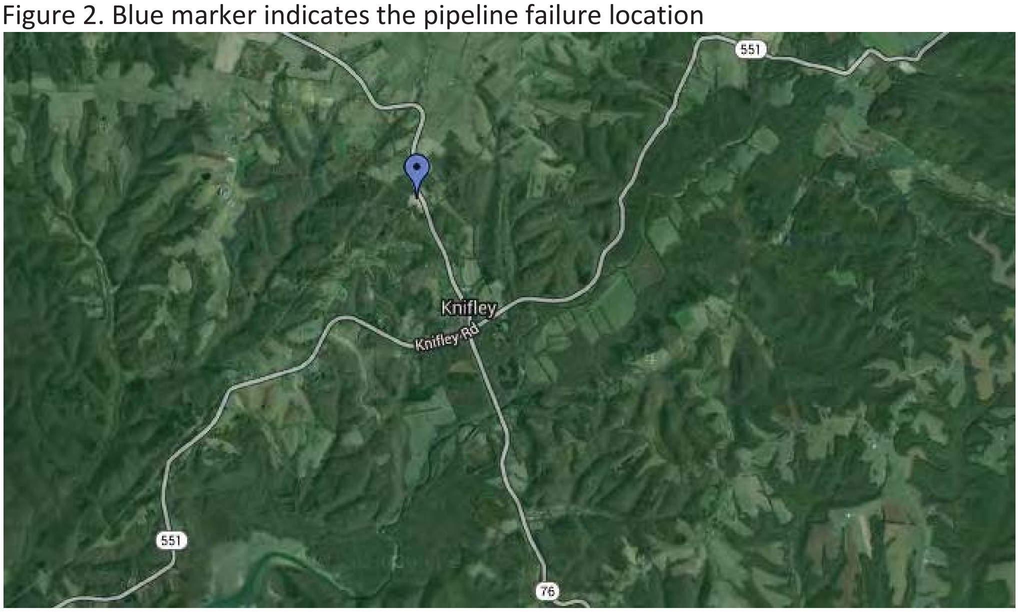
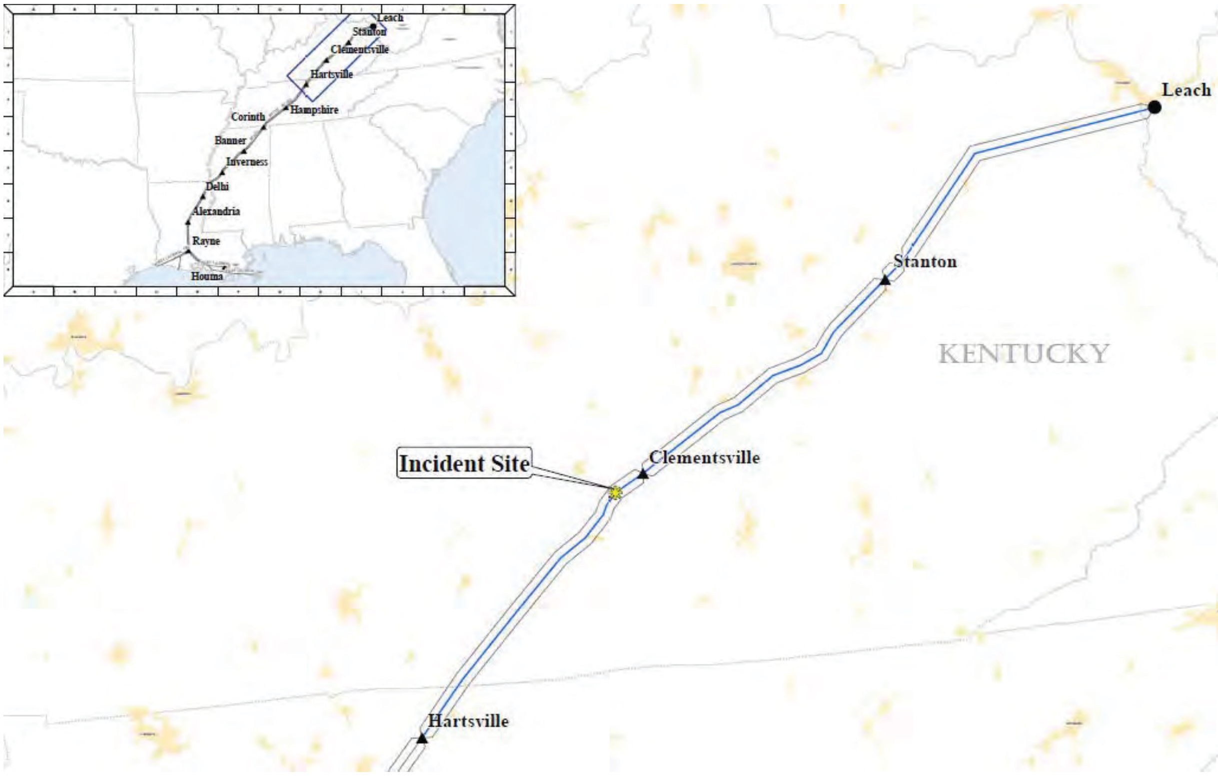


Figure 3. Blue marker indicates the pipeline failure location

Appendix A Maps and Photographs

Figure 4. Line 200 Failure Location



(b) (7)(F)

[redacted]

Appendix A Maps and Photographs

Figure 6. KY State Route 76 covered with debris from the pipeline rupture (looking west)

Figure 7. South terminus of Line 200 failure (looking south)

Figure 8. South terminus (closer view)

Figure 9. North terminus of Line 200 failure and Line 200/300 right of way (looking north)

Figure 10. North terminus (closer view)

Figure 11. 44-foot expelled pipe section

Figure 12. 2-foot expelled pipe piece

Figure 13. 31-foot expelled pipe section

Figure 14. 6-foot expelled pipe section

Figure 15. 2-foot expelled pipe section

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

February 14, 2014

<u>VIA CERTIFIED MAIL AND FAX TO:</u> (304) 357-2644

Mr. Shawn L. Patterson
President
Columbia Gulf Transmission Company
1700 MacCorkle Avenue, SE
Charleston, WV 25314

Re: CPF No. 2-2014-1001H

Dear Mr. Patterson:

Enclosed is a Corrective Action Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. It requires you to take certain corrective actions with respect to the operation of Columbia Gulf Transmission's Line 200 in Kentucky and Tennessee northeast of the Hartsville Compressor Station. The Corrective Action Order requires you to take immediate action to protect the public, property, and environment in connection with the failure of this pipeline on February 13, 2014, near Knifley, Kentucky.

Service is being made by certified mail and facsimile. Your receipt of this Corrective Action order constitutes service of that document under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon receipt. Please direct any questions on this matter to Wayne T. Lemoi, Director, Southern Region, OPS, at (404) 832-1160.

Sincerely,

for: Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Wayne T. Lemoi, Southern Region Director, OPS

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
Columbia Gulf Transmission Company,	)	**CPF No. 2-2014-1001H**
Respondent	)	

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order is being issued, under authority of 49 U.S.C. § 60112, to require Columbia Gulf Transmission Company (Respondent or CGT), to take the necessary corrective actions to protect the public, property, and the environment from potential hazards associated with a failure of CGT's Line 200 natural gas pipeline, that occurred between the Clementsville Compressor Station and the first immediate downstream valve setting, near Knifley, Kentucky, in Adair County.

On February 13, 2014, a failure occurred on Respondent's 30-inch line approximately 0.75 miles north of Knifley, Kentucky, and approximately 8.7 miles south of the Clementsville Compressor Station, resulting in the release of natural gas. The cause of the failure has not yet been determined.

Pursuant to 49 U.S.C. § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety, Southern Region initiated an investigation of the incident. The preliminary findings of the investigation are as follows:

Preliminary Findings

- The Columbia Gulf Transmission (CGT) natural gas pipeline system is part of the Columbia Pipeline Group. It originates along the Gulf Coast of the United States and transports natural gas through Louisiana, Mississippi, Tennessee, and Kentucky. CGT's pipeline system terminates at the Leach Meter Station, approximately 3 miles south of Catlettsburg, Kentucky, where the natural gas is transferred to another Columbia Pipeline Group company, Columbia Gas Transmission. The CGT pipeline system consists of three natural gas transmission pipelines as follows:

  - Line 100, 30-inch outside diameter MAOP of 935 psig
  - Line 200, 30-inch outside diameter, MAOP of 1,008 psig (the ruptured line)
  - Line 300, 36-inch outside diameter, MAOP of 1,008 psig

- At approximately 2:05 am EST on February 13, 2014, a rupture occurred on Respondent's 30-inch 200 Line, resulting in a reported release of approximately 26.3 MMCF of natural gas.

- CGT reported the incident to the National Response Center on February 13, 2014 (NRC Report No. 1073825).

- In Kentucky Line 200 is one of CGT's three parallel natural gas transmission pipelines. The other lines are Line 100 and Line 300. Line 200 crosses over the Tennessee/ Kentucky border northeast of Nashville and then runs from the southwest to the northeast through Kentucky terminating at the Leach Meter Station, approximately 3 miles south of Catlettsburg, KY.

- The failure occurred in a remote location with several houses, several barns, and other buildings within a mile of the pipeline.
  - The released natural gas ignited causing a fire that destroyed two houses, three small buildings, one carport and four cars. It also damaged one other house and several other buildings.
  - Two persons were injured, treated for burns at a local hospital, and released. There were no reported fatalities. Four persons were unable to return to their homes.

- Following the February 13, 2014 failure, CGT personnel shut down compressor unit # 1 at the Clementsville Compressor Station (CS) at 02:08 a.m. eliminating the discharge of gas. They then closed a valve on the discharge side of the station at 02:11 a.m. using a valve actuator. Valve 313, approximately 13.92 miles downstream (south) of the CS, was already closed at the time of the failure. CGT dispatched personnel to complete the isolation of the pipeline by closing the Adair Interconnect valve, approximately 11.81 miles south of the Clementsville Compressor Station. The isolation was complete approximately 30-35 minutes after the pressure drop. CGT later discovered that Valve 313 was leaking so CGT personnel shut down valve 312, which was the next downstream main line block valve and located approximately 25.20 miles downstream of the CS.

- At the time of the incident, the estimated failure site operating pressure of Line 200 was 961 psig. The reported maximum allowable operating pressure (MAOP) of this line segment is 1008 psig.

- Line 200 is shut-in from valve 312 at pipeline station number 3294 +56 (approximately 25.20 miles south of the Clementsville Compressor Station to a discharge valve on the south side of the Clementsville Compressor Station. When it is returned to service the pressure will not exceed 769 psig.

- The Line 200 pipe was manufactured by U.S. Steel in 1965. The pipe is 30-inch, 0.323-inch w.t., X-65, coated with modified primer enamel with fiberglass and kraft paper.

- The cause of the failure is unknown and the investigation is ongoing.

Determination of Necessity for Corrective Action Order and Right to Hearing

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, requiring corrective action, which may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or other action as appropriate. The basis for making the determination that a pipeline facility is hazardous, requiring corrective action, is set forth both in the above referenced statute and 49 C.F.R. §190.233, a copy of which is enclosed.

Section 60112, and the regulations promulgated thereunder, provide for the issuance of a Corrective Action Order without prior opportunity for notice and hearing upon a finding that failure to issue the Order expeditiously will result in likely serious harm to life, property or the environment. In such cases, an opportunity for a hearing will be provided as soon as practicable after the issuance of the Order.

After evaluating the foregoing preliminary findings of fact, I find that the continued operation of portions of Respondent's Line 200 in Tennessee and Kentucky, without corrective measures, would be hazardous to life, property and the environment. Additionally, after considering the age of the pipe, circumstances surrounding this failure, the proximity of the pipeline to populated areas and public roadways the hazardous nature of the product the pipeline transports, the pressure required for transporting the material, the uncertainties as to the cause of the failure, and the ongoing investigation to determine the cause of the failure, I find that a failure to issue this Order expeditiously to require immediate corrective action would result in likely serious harm to life, property, and the environment.

Accordingly, this Corrective Action Order mandating immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, delivered personally, by mail or by telecopy at (202) 366-4566. The hearing will be held in Atlanta, Georgia or Washington, D.C. on a date that is mutually convenient to PHMSA and Respondent.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken. CGT will be notified of any additional measures required and amendment of this Order will be considered. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Action

The *"Affected Segment"* below means approximately 254.35 miles of CGT's 30-inch Line 200 from the Hartville Compressor Station in Tennessee to the Leach Meter Station, approximately 3 miles south of Catlettsburg, Kentucky.

The *"Isolated Segment"* means the 25.20-mile segment of CGTs 30-inch Line 200 from main line valve 312 at Station 3294+56 to a block valve on the discharge side of the Clementsville Compressor Station at station 4625+30. It is the portion of the "Affected Segment" that was shut-in after the failure on February 13, 2014, and that must remain shut-in until a restart plan is approved by the "Director."

The *"Director"* means the Director, Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety, Southern Region. The Director's address is 233 Peachtree St., Suite 600, Atlanta, GA 30303.

Pursuant to 49 U.S.C. § 60112, I hereby order CGT to immediately take the following corrective actions with respect to the Line 200 pipeline:

1. ***Isolated Segment Shut In.*** CGT must not operate the Isolated Segment until authorized to do so by the Director.
2. ***Operating Pressure Restriction.*** CGT must reduce and maintain a twenty percent (20%) pressure reduction in the actual operating pressure along the entire length of the Affected Segment such that the operating pressure along the Affected Segment will not exceed eighty percent (80%) of the actual operating pressure in effect immediately prior to the failure on February 13, 2014.
    a. This pressure restriction is to 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.
    b. By February 20, 2014, CGT must provide the Director the actual operating pressures of each compressor station and each main line pressure regulating station on the Affected Segment at the time of failure and the reduced pressure restriction set-points at these same locations.
    c. This pressure restriction requires any relevant remote or local alarm limits, software programming set-points or control points, and mechanical over-pressure devices to be adjusted accordingly.
    d. When determining the pressure restriction set-points, CGT must take into account any in-line inspection (ILI) features or anomalies present in the Affected Segment

to provide for continued safe operation while further corrective actions are completed.

e. CGT must review the pressure restriction monthly by analyzing the operating pressure data. Take into account any ILI features or anomalies present in the Affected Segment and immediately reduce the operating pressure to maintain the safe operations of the Affected Segment, if warranted by the monthly review. Submit the results of the monthly review to the Director. The results must include, at a minimum, the current discharge set-points (including any additional pressure reductions), and any pressure exceedance at discharge set-points.

3. ***Restart Plan.*** Prior to resuming operation of the Isolated Segment, develop and submit a written Restart Plan to the Director for prior approval.

   a. The Director may approve the Restart Plan incrementally without approving the entire plan but the Isolated Segment cannot resume operation until the Restart Plan is approved in its entirety.

   b. Once approved by the Director, the Restart Plan will be incorporated by reference into this Order.

   c. The Restart Plan must provide for adequate patrolling of the Isolated Segment during the restart process and must include incremental pressure increases during start-up, with each increment to be held for at least 2 hours.

   d. The Restart Plan must include sufficient surveillance of the pipeline during each pressure increment to ensure that no leaks are present when operation of the line resumes.

   e. The Restart Plan must specify a day-light restart and include advance communications with local emergency response officials.

   f. The Restart Plan must provide for a review of the Isolated Segment for conditions similar to those of the failure including a review of construction, operating and maintenance (O&M) and integrity management records such as ILI results, hydrostatic tests, root cause failure analysis of prior failures, aerial and ground patrols, corrosion, cathodic protection, excavations and pipe replacements. Operator must address any findings that require remedial measures to be implemented prior to restart.

   g. The Restart Plan must also include documentation of the completion of all mandated actions, and a management of change plan to ensure that all procedural modifications are incorporated into CGT's operations and maintenance procedures manual.

   h. Prior to restart, submit to the Director a contingency plan to operate and monitor the Isolated Segment during flooding conditions, including enhanced patrolling and surveillance.

4. ***Return to Service.*** After the Director approves the Restart Plan, CGT may return the Isolated Segment to service but the operating pressure must not exceed eighty percent

(80%) of the actual operating pressure in effect immediately prior to the failure on February 13, 2014, in accordance with Item 2 above.

5. ***Removal of Pressure Restriction***.

    a. The Director may allow the removal or modification of the pressure restriction upon a written request from CGT demonstrating 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 and considering all known defects, anomalies, and operating parameters of the pipeline.

    b. The Director may allow the temporary removal or modification of the pressure restrictions upon a written request from CGT 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 and mitigative actions taken by the operator provide for the safe operation of the Affected Segment during the temporary removal or modification of the pressure restriction. Appeals to determinations of the Director in this regard will be decided by the Associate Administrator for Pipeline Safety.

6. ***Instrumented Leakage Survey***. Within 30 days of receipt of this Order, CGT must perform an aerial or ground instrumented leakage survey of the Affected Segment. CGT must investigate all leak indications and remedy all leaks discovered. CGT must submit documentation of this survey to the Director within 45 days of receipt of this Order.

7. ***Records Verification***. As recommended in PHMSA Advisory Bulletin 2012-06, verify the records for the Affected Segment to confirm the maximum allowable operating pressure (MAOP). CGT must submit documentation of this this record verification to the Director within 45 days of receipt of this Order.

8. ***Review of Prior Inline Inspection (ILI) Results.*** Within 30 days of receipt of this Order, conduct a review of any previous ILI results of the Affected Segment. Re-evaluate all ILI results from the past 10 calendar years; include a review of the ILI vendors' raw data and analysis. Determine whether any features were present in the failed pipe joint and/or any other pipe removed. Also, determine if any features with similar characteristics are present elsewhere on the Affected Segment. CGT must submit documentation of this ILI review to the Director within 45 days of receipt of this Order as follows:

    a. List all ILI tool runs, tool types, and the calendar years of the tool runs.

    b. List, describe (type, size, wall loss, etc.), and identify the specific location of all ILI features present in the failed joint and/or other pipe removed.

    c. List, describe (type, size, wall loss, etc.), and identify the specific location of all ILI features with similar characteristics present elsewhere on the Affected Segment.

    d. Explain the process used to review the ILI results and the results of the reevaluation.

9. ***Mechanical and Metallurgical Testing.*** Within 45 days of receipt of this Order, complete mechanical and metallurgical testing and failure analysis of the failed pipe, including an 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 and other evidence from the failure site.

    b. Within10 days of receipt of this Order, develop and submit the testing protocol and the proposed testing laboratory to the Director for prior approval.

    c. Prior to beginning the mechanical and metallurgical testing, provide the Director with the scheduled date, time, and location of the testing to allow for an OPS representative to witness the testing.

    d. Ensure the testing laboratory distributes all reports whether draft or final in their entirety to the Director at the same time they are made available to CGT.

10. ***Root Cause Failure Analysis.*** Within 90 days following receipt of this Order, complete a root cause failure analysis (RCFA) and submit a final report of this RCFA to the Director. The RCFA must be supplemented/facilitated by an independent third-party acceptable to the Director and must document the decision making process and all factors contributing to the failure. The final report must include findings and any lessons learned and whether the findings and any lessons learned are applicable to other locations within CGT's pipeline system.

11. ***Emergency Response Plan and Training Review.*** CGT must review and assess the effectiveness of its emergency response plan with regards to the failure to include actions CGT took on February 13, 2014, to isolate and make the pipeline safe. Include in the review and assessment the on-scene response and support, coordination, and communication with emergency responders and public officials. Also, include a review and assessment of the effectiveness of its emergency training program. CGT must amend its emergency response plan and emergency training, if necessary, to reflect the results of this review. The documentation of this Emergency Response Plan and Training Review must be available for inspection by OPS or provided to the Director, if requested.

12. ***Public Awareness Program Review.*** CGT must review and assess the effectiveness of its Public Awareness Program with regards to the failure. CGT must amend its Public Awareness Program, if necessary, to reflect the results of this review. The documentation of this Public Awareness Program Review must be available for inspection by OPS or provided to the Director, if requested.

13. ***Integrity Verification and Remediation Plan (IVRP).***

    a. Within 90 days following receipt of this Order, CGT must submit an Integrity Verification and Remediation Plan (IVRP) to the Director for approval.

    b. The Director may approve the IVRP incrementally without approving the entire IVRP.

c. Once approved by the Director, the IVRP will be incorporated by reference into this Order.

d. The IVRP must specify the tests, inspections, assessments, evaluations, and remedial measures CGT will use to verify the integrity of the Affected Segment. It must address all known or suspected factors and causes of the February 13, 2014, failure. CGT should consider both the risk of another failure and the consequence of another failure to develop a prioritized schedule for IVRP related work along the Affected Segment.

e. The IVRP must include a procedure or process to:

   i. Identify pipe in the Affected Segment with characteristics similar to the contributing factors identified for the February 13, 2014, failure.

   ii. Gather all data necessary to review the failure history (in service and pressure test failures) of the Affected Segment and to prepare a written report containing all the available information such as the locations, dates, and causes of leaks and failures.

   iii. Integrate the results of the metallurgical testing, root cause failure analysis, and other corrective actions required by this Order with all relevant pre-existing operational and assessment data for the Affected Segment. Pre-existing operational data includes, but is not limited to, construction, operations, maintenance, testing, repairs, prior metallurgical analyses, and any third party consultation information. Pre-existing assessment data includes, but is not limited to, ILI tool runs, hydrostatic pressure testing, direct assessments, close interval surveys, and DCVG/ACVG surveys.

   iv. Determine if conditions similar to those contributing to the failure on February 13, 2014, are likely to exist elsewhere on the Affected Segment.

   v. Conduct additional field tests, inspections, assessments, and/or evaluations to determine whether, and to what extent, the conditions associated with the failure on February 13, 2014, and other failures from the failure history [see 13(e)(ii) above] or any other integrity threats are present elsewhere on the Affected Segment. At a minimum, this process must consider all failure causes and specify the use of one or more of the following:

      1. ILI tools that are technically appropriate for assessing the pipeline system based on the cause of failure on February 13, 2014, and that can reliably detect and identify anomalies,

      2. Hydrostatic pressure testing,

      3. Close-interval surveys,

      4. Cathodic protection surveys, to include interference surveys in coordination with other utilities (e.g. underground utilities, overhead power lines, etc.) in the area,

5. Coating surveys,
6. Stress corrosion cracking surveys,
7. Selective seam corrosion surveys; and,
8. Other tests, inspections, assessments, and evaluations appropriate for the failure causes.

   Note: CGT may use the results of previous tests, inspections, assessments, and evaluations if approved by the Director, provided the results of the tests, inspections, assessments, and evaluations are analyzed with regard to the factors known or suspected to have caused the February 13, 2014, failure.

vi. Describe the inspection and repair criteria CGT will use to prioritize, excavate, evaluate, and repair anomalies, imperfections, and other identified integrity threats. Include a description of how any defects will be graded and a schedule for repairs or replacement.

vii. Based on the known history and condition of the Affected Segment, describe the methods CGT will use to repair, replace, or take other corrective measures to remediate the conditions associated with the pipeline failure on February 13, 2014, and to address other known integrity threats along the Affected Segment. The repair, replacement, or other corrective measures must meet the criteria specified in 13(e)(vi) above.

viii. Implement continuing long-term periodic testing and integrity verification measures to ensure the ongoing safe operation of the Affected Segment considering the results of the analyses, inspections, evaluations, and corrective measures undertaken pursuant to the Order.

ix. Implement specific actions CGT will take on its entire pipeline system as a result of the lessons learned from work on this Order.

f. Include a proposed schedule for completion of the IVRP.

g. CGT must revise the IVRP as necessary to incorporate new information obtained during the failure investigation and remedial activities, to incorporate the results of actions undertaken pursuant to this Order, and/or to incorporate modifications required by the Director.

   i. Submit any plan revisions to the Director for prior approval.

   ii. The Director may approve plan revisions incrementally.

   iii. Any and all revisions to the IVRP after it has been approved and incorporated by reference into this Order will be fully described and documented in the CAO Documentation Report (CDR).

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

14. ***CAO Documentation Report (CDR)***. CGT must create and revise, as necessary, a CAO Documentation Report (CDR). When CGT has concluded all the items in this Order it will submit the final CDR in its entirety to the Director. This will allow the Director to complete a thorough review of all actions taken by CGT with regards to this Order prior to approving the closure of this Order. The intent is for the CDR to capture summations of all activities and the documentation associated with this Order in one document.

    a. The Director may approve the CDR incrementally without approving the entire CDR.

    b. Once approved by the Director, the CDR will be incorporated by reference into this Order.

    c. The CDR must include but not be limited to:

        i. Table of Contents;

        ii. Summary of the pipeline failure of February 13, 2014, and the response activities;

        iii. Summary of pipe data/properties and all prior assessments of the Affected Segment;

        iv. Summary of all tests, inspections, assessments, evaluations, and analysis required by the Order;

        v. Summary of the Mechanical and Metallurgical Testing as required by the Order;

        vi. Summary of the RCFA with all root causes as required by the Order;

        vii. Documentation of all actions taken by CGT to implement the IVRP, the results of those actions, and the inspection and repair criteria used;

        viii. Documentation of any revisions to the IVRP including those 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;

        ix. Lessons learned while completing this Order;

        x. A description of the specific actions CGT will take on its entire pipeline system as a result of the lessons learned from work on this Order; and

        xi. Appendices (if required).

<u>OTHER REQUIREMENTS</u>

1. ***Reporting.*** Submit quarterly reports to the Director that: (1) include all available data and the 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 is due on April 10, 2014. Subsequent quarterly reports are due 10 days after the close of the calendar

close of the calendar quarter; e.g. 1st quarter - due April 10, 2014, 2nd quarter - due July 10, 2014, 3rd quarter - due October 10, 2014. The Director may change the interval for the submission of these reports.

2. ***Documentation of the Costs***. It is requested but not required that Respondent 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.

3. ***Approvals.*** 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 Respondent modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, Respondent shall 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, Respondent must correct all deficiencies within the time specified by the Director, and resubmit it for approval.

4. ***Extensions of Time***. 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.

The actions required by this Order are in addition to and do not waive any requirements that apply to Respondent's pipeline system under 49 C.F.R. Part 192, under any other order issued to Respondent under authority of 49 U.S.C. § 60101 et seq., or under any other provision of Federal or State law.

Respondent may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator are final.

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

The terms and conditions of this Corrective Action Order are effective upon receipt.

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Date Issued

Appendix C

DNV GL Metallurgical Analysis of the Line 200 Failure

This document is on file at PHMSA

KARST OCCURRENCE IN KENTUCKY

Randall L. Paylor and
James C. Currens

This map was compiled from a digital version of the 1:500,000-scale geologic map of Kentucky (Noger, M.C., comp., 1988, Geologic map of Kentucky: U.S. Geological Survey). The areas of potential karst development were delineated using stratigraphic units mapped on the geologic map. The classification of the potential for karst development was based on the field experience of the authors and other data. A number of isolated carbonate units that would not have otherwise been differentiated on the geologic map were newly digitized for this map.

This karst map should not be used for evaluating karst geologic hazards or hydrogeology at scales larger than 1:500,000. The base geologic map was digitized at 1:500,000 scale and is limited in precision to that scale. Because of the small scale of the original geologic map, lithostratigraphic units were consolidated into thicker chronostratigraphic units to create an area large enough to delineate on the geologic map. In some cases, the consolidation resulted in carbonates (limestone or dolomite) and noncarbonates (sandstone or shale, for example) being grouped; these rocks are not redivided on this map. Although the potential for karst development can be predicted from lithology, other factors such as relief and length of time the rock is exposed are also important and were not considered in the making of this map. Finally, areas where the near-surface bedrock is insoluble and closely underlain by soluble rock are common, particularly in the Eastern Pennyroyal. Conduits that pirate drainage commonly extend through ridges capped with insoluble rocks. Therefore, some areas mapped as having limited potential that are adjacent to areas of higher potential are actually karst, but cannot be differentiated on this map.

Karst is a terrane that is generally underlain by limestone or dolomite, where the topography is formed chiefly by the dissolving of rock. Karst landscapes are commonly characterized by sinkholes, sinking streams, closed depressions, subterranean drainage, large springs, and caves.

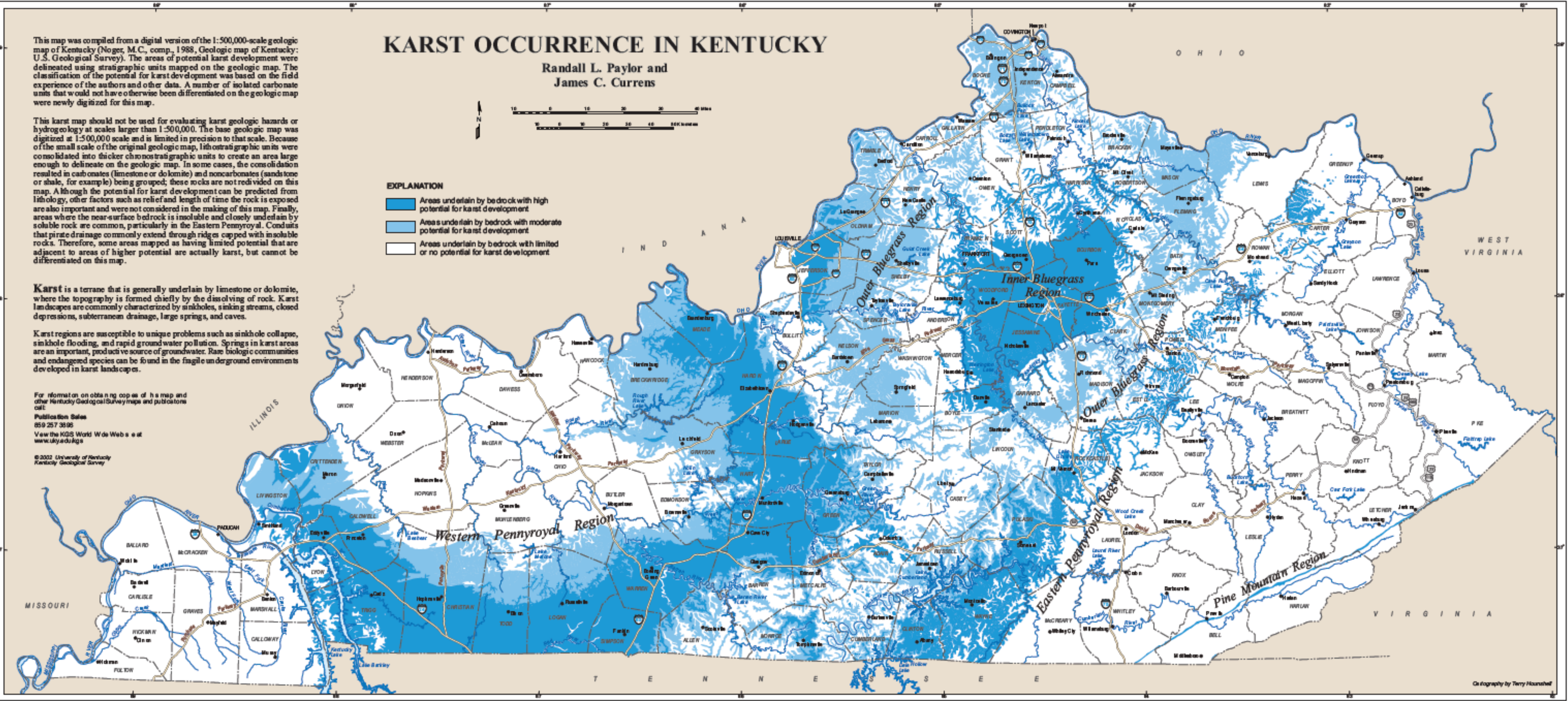
Karst regions are susceptible to unique problems such as sinkhole collapse, sinkhole flooding, and rapid groundwater pollution. Springs in karst areas are an important, productive source of groundwater. Rare biologic communities and endangered species can be found in the fragile underground environments developed in karst landscapes.

For information on obtaining copies of this map and other Kentucky Geological Survey maps and publications call:

Publication Sales

859 257 3896

View the KGS World Wide Web site at www.uky.edu/kgs



Cartography by Terry Hounshell

Appendix E

Pipeline failure location relative to karst prone region (shaded area)

(b) (7)(F)

[redacted]

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

Incident Report # 1073825

INCIDENT DESCRIPTION

*Report taken by: CIV NICHAULUS THREATT at 02:49 on 13-FEB-14
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident was discovered on 13-FEB-14 at 02:15 local incident time.
Affected Medium: UNKNOWN

REPORTING PARTY
Name: GREG LAGO
Organization: COLUMBIA GULF PIPELINE
Address: 1700 MACORKLE AVE
CHARLESTON, WV 25314
COLUMBIA GULF PIPELINE reported for the responsible party.
PRIMARY Phone: (304)5451477
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY
Name: GREG LAGO
Organization: COLUMBIA GULF PIPELINE
Address: 1700 MACORKLE AVE
CHARLESTON, WV 25314
PRIMARY Phone: (304)5451477

INCIDENT LOCATION
170 JACKIE HOLLOW HWY County: CASEY
City: LIBERTY State: KY
NEAR THE CLEMENTSVILLE COMPRESSOR STATION

RELEASED MATERIAL(S)
CHRIS Code: ONG Official Material Name: NATURAL GAS
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT Qty in Water: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT
CALLER IS REPORTING A RELEASE OF NATURAL GAS FROM A 30 INCH PIPELINE
DUE TO AN UNKNOWN CAUSE AT THIS TIME.

SENSITIVE INFORMATION

INCIDENT DETAILS

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

IMPACT

Fire Involved: YES Fire Extinguished: UNKNOWN

INJURIES: UNKNOWN Hospitalized: Empl/Crew: Passenger:
FATALITIES: UNKNOWN Empl/Crew: Passenger: Occupant:
EVACUATIONS:UNKNOWN Who Evacuated: Radius/Area:

Damages: NO

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

Environmental Impact: UNKNOWN
Media Interest: UNKNOWN Community Impact due to Material:

REMEDIAL ACTIONS

THE PIPELINE IS SHUT IN AND PERSONNEL ARE EN ROUTE.
Release Secured: UNKNOWN
Release Rate:
Estimated Release Duration:

WEATHER

Weather: SNOWY, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal:
State/Local: FIRE DEPT.
State/Local On Scene:

State Agency Number:

NOTIFICATIONS BY NRC

CGIS RAO ST. LOUIS (COMMAND CENTER)
13-FEB-14 02:59 (314)2692420
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
13-FEB-14 02:59 (202)3661863
U.S. EPA IV (MAIN OFFICE)
(404)6504955
EPA IV KENTUCKY (MAIN OFFICE)
13-FEB-14 02:59
USCG NATIONAL COMMAND CENTER (MAIN OFFICE)
(202)3722100
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
13-FEB-14 02:59 (202)2829201
NOAA RPTS FOR KY (MAIN OFFICE)
13-FEB-14 02:59 (206)5264911
NATIONAL RESPONSE CENTER HQ (MAIN OFFICE)
(202)2671136
NATIONAL RESPONSE CENTER HQ (AUTOMATIC REPORTS)
13-FEB-14 02:59 (202)2671136
NTSB PIPELINE (MAIN OFFICE)
13-FEB-14 02:59 (202)3146293
KY DEP/ERT (MAIN OFFICE)
13-FEB-14 02:59 (800)9282380
KY DEP/ERT (DUTY OFFICER)
13-FEB-14 02:59 (800)2552587
USCG DISTRICT 8 (MAIN OFFICE)
13-FEB-14 02:59 (504)5896225

ADDITIONAL INFORMATION

THEY RECEIVED A REPORT FROM THEIR MONITORING CENTER OF A FIRE IN THE AREA. THEY ALSO NOTICED THE PRESSURE DROP ON THE PIPELINE BUT IT IS UNKNOWN IF THE ACTUAL PIPELINE CAUGHT ON FIRE.

*** END INCIDENT REPORT #1073825 ***

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

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

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0522 EXPIRATION DATE: 02/28/2014

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	03/12/2014
	No.	20140027 - 16447 (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:	07/03/2014
1. Operator's OPS-issued Operator Identification Number (OPID):	2620
2. Name of Operator	COLUMBIA GULF TRANSMISSION CO
3. Address of Operator:	
3a. Street Address	1700 MCCORKLE AVE
3b. City	CHARLESTON
3c. State	West Virginia
3d. Zip Code:	25314
4. Local time *(24-hr clock)* and date of the Incident:	02/13/2014 02:04
5. Location of Incident:	
Latitude:	(b) (7)(F) [redacted]
Longitude:	
6. National Response Center Report Number (if applicable):	1073825
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	02/13/2014 02:49
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):	26,300.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	14,900.00
12. Estimated volume of accompanying liquid release (Barrels):	
13. Were there fatalities?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total fatalities (sum of above)	
14. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
14a. Operator employees	
14b. Contractor employees working for the Operator	
14c. Non-Operator emergency responders	
14d. Workers working on the right-of-way, but NOT associated with this Operator	
14e. General public	
14f. Total injuries (sum of above)	

15. Was the pipeline/facility shut down due to the incident?	Yes
- If No, Explain:	
- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	02/13/2014 02:11
15b. Local time pipeline/facility restarted	
- Still shut down? (* Supplemental Report Required)	Yes
16. Did the gas ignite?	Yes
17. Did the gas explode?	Yes
18. Number of general public evacuated:	
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	02/13/2014 02:05
19b. Local time operator resources arrived on site	02/13/2014 03:45

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:	Kentucky
3. Zip Code:	42753
4. City	Knifley
5. County or Parish	Adair
6. Operator designated location	Survey Station No.
Specify:	4164+02
7. Pipeline/Facility name:	Line 200
8. Segment name/ID:	(b) (7)(F) [redacted]
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):	104
12. Did Incident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
Name of body of water (If commonly known):	
Approx. water depth (ft) at the point of the Incident:	
Select:	
If Offshore:	
13. Approx. water depth (ft) at the point of the Incident:	
14. Origin of Incident:	
- If "In State waters":	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- If "On the Outer Continental Shelf (OCS)":	
- Area:	
- Block #:	
15. Area of Incident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility: - Interstate - Intrastate	Interstate
2. Part of system involved in Incident:	Onshore Pipeline, Including Valve Sites
3. Item involved in Incident:	Weld, including heat-affected zone
- If Pipe – Specify:	
3a. Nominal diameter of pipe (in):	30
3b. Wall thickness (in):	.323

3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	65,000
3d. Pipe specification:	API5L
3e. Pipe Seam – Specify:	DSAW
- If Other, Describe:	
3f. Pipe manufacturer:	US Steel Corp
3g. Year of manufacture:	1965
3h. Pipeline coating type at point of Incident – Specify:	Other
- If Other, Describe:	Modified primer & enamel with fiberglass and kraft paper
- If Weld, including heat-affected zone – Specify:	Pipe Girth Weld
- If Other, Describe:	
- If Valve – Specify:	
- If Mainline – Specify:	
- If Other, Describe:	
3i. Mainline valve manufacturer:	
3j. Year of manufacture:	
- If Other, Describe:	
4. Year item involved in Incident was installed:	1965
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:	Other
- If Other – Describe:	Pipe rupture. Approximately 80 feet of pipe expelled.
Approx. size: in. (widest opening):	30
by in. (length circumferentially or axially):	960
- 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:	657
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?	Yes
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	$ 550,000
7b. Estimated cost of Operator's property damage & repairs	$ 492,056
7c. Estimated cost of Operator's emergency response	$ 39,084
7d. Estimated other costs	$ 480,511
Describe:	Incident investigation
7e. Total estimated property damage (sum of above)	$ 1,561,651
Cost of Gas Released	
7f. Estimated cost of gas released unintentionally	$ 152,158
7g. Estimated cost of gas released during intentional and controlled blowdown	$ 86,204
7h. Total estimated cost of gas released (sum of 7.f & 7.g above)	$ 238,362

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	964.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	1,008.00
2.a MAOP established by 49 CFR section:	

-Details:	
3. Describe the pressure on the system or facility relating to the Incident:	Pressure did not exceed MAOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Incident operating under an established pressure restriction with pressure limits below those normally allowed by the MAOP?	No
- If Yes - (*Complete 4a and 4b below)*	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5e. below):*	
5a. Type of upstream valve used to initially isolate release source:	Manual
5b. Type of downstream valve used to initially isolate release source:	Manual
5c. Length of segment isolated between valves (ft):	73,550
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 contr buting factor to the Incident?	Yes, specify investigation result(s): (select all that apply)
- 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)*	
- If Yes, Descr be investigation result(s) *(select all that apply)*:	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the operator), and other factors associated with fatigue	Yes

- 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	Yes
- Investigation identified no controller issues	Yes
- 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:	2
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. Descr be 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:	G2 - Natural 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 inh bitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
14. Has one or more internal inspection tool collected data at the point of the Incident?	
14a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage Tool	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
If Other, Describe:	
15. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes,	
Most recent year tested:	
Test pressure (psig):	
16. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	

Most recent year conducted:	
17. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
17a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year examined:	
- Guided Wave Ultrasonic	
Most recent year examined:	
- Handheld Ultrasonic Tool	
Most recent year examined:	
- Wet Magnetic Particle Test	
Most recent year examined:	
- Dry Magnetic Particle Test	
Most recent year examined:	
- Other	
Most recent year examined:	
If Other, Describe:	

G2 - Natural Force Damage - *only one* ***sub-cause*** *can be picked from shaded left-handed column*

Natural Force Damage – Sub-Cause:	Earth Movement, NOT due to Heavy Rains/Floods
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	Other
- If Other, Descr be:	Root Cause Failure Analysis including geotechnical survey indicates most likely cause of failure was external loading acting on the pipe and land movement was the probable cause of the external loading leading to the incident.
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Descr be:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Descr be:	
- 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?	No
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 vis ble in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption: (hours)	
17. Description of the **CGA-DIRT Root Cause** (*select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, then one predominant second level CGA-DIRT Root Cause as well*):	
- Predominant first level CGA-DIRT Root Cause:	
- If One-Call Notification Practices Not Sufficient, Specify:	
- If Locating Practices Not Sufficient, Specify:	
- If Excavation Practices Not Sufficient, Specify:	
- If Other/None of the Above, Explain:	
G4 - Other Outside Force Damage - only one **sub-cause** can be selected from the shaded left-hand column	
Other Outside Force Damage – Sub-Cause:	
- If 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, Descr be:	
- 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 - 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 contr buting 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 contr buting 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

Root Cause Failure Analysis submitted to PHMSA Southern Regional Office on 5/9/2014. All times shown in Eastern Standard Time.

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Gregory Lago
Preparer's Title	Principal Engineer
Preparer's Telephone Number	(304) 357-2465
Preparer's E-mail Address	glago@nisource.com
Preparer's Facsimile Number	(304) 357-3804
Authorized Signature's Name	Perry M. Hoffman
Authorized Signature Title	Manager of System Integrity
Authorized Signature Telephone Number	(304) 357-2548
Authorized Signature Email	m kehoffman@nisource.com
Date	07/03/2014