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

Principal Investigator	Chris Taylor
Region Director	Wayne T. Lemoi
Date of Report	June 26, 2013
Subject	Failure Investigation Report – Columbia Gulf Transmission, Line 200 Rupture in Estill County Kentucky

Operator, Location, & Consequences

Date of Failure	January 2, 2012
Commodity Released	Natural Gas
City/County & State	Hargett/Estill, Kentucky
OpID & Operator Name	2620 & Columbia Gulf Transmission
Unit # & Unit Name	2012 & KY-1
SMART Activity #	137380
Milepost / Location	Milepost 68.3/37.792666 N, 84.02975W
Type of Failure	Rupture and fire due to pipeline overstress from land movement
Fatalities	None
Injuries	None
Description of area impacted	Columbia Gulf Transmission Line 200 is a 30-inch diameter natural gas transmission pipeline that ruptured, expelled pipe pieces, and created a crater approximately 86 feet long and 22 feet wide. An ensuing fire burned trees in the immediate area of the rupture, which was south of KY Highway 89 (Winchester Road). The heat from the fire deformed the vinyl siding on a mobile home located over 800 feet from the rupture. The incident occurred in a non-HCA Class 1 location.
Total Costs	$1,688,065

Executive Summary

On January 2, 2012, Columbia Gulf Transmission's (CGT's) Line 200 experienced a rupture in Hargett, Kentucky, a rural community in Estill County located approximately 45 miles southeast of Lexington, Kentucky. Line 200 is a 30-inch outside diameter natural gas transmission pipeline which operated at a maximum allowable operating pressure (MAOP) of 1,008 psig. Line 200 is part of CGT's natural gas transmission pipeline system that also includes Line 100 (30-inch) and Line 300 (36-inch) in Kentucky.

The rupture created a crater approximately 86 feet long by 22 feet wide and expelled a number of pieces of pipe as far as 800 feet from the rupture centerline. The escaping natural gas ignited and burned adjacent trees and farmland. The heat from the fire also deformed the vinyl siding on a mobile home trailer over 800 feet away. Local authorities blocked a 1.3-mile section of Kentucky Highway 89 (Winchester Road) until the fire fighters extinguished the fire.

Approximately 30 people were evacuated from their homes. While no one was injured as a direct result of the pipeline rupture, some sustained minor injuries during the evacuation. There were no fatalities.

CGT first became aware of the rupture when its Stanton Compressor Station employee observed a pressure drop on the suction side of Line 200 at approximately 7:00 p.m. Eastern Standard Time (EST). At 7:10 p.m., CGT received calls from residents near the rupture reporting a fire on what they believed was a CGT pipeline. At 7:15 p.m., CGT confirmed the rupture of its Line 200 pipeline. After the CGT Monitoring Center and Gas Control confirmed the Line 200 rupture, CGT personnel isolated the rupture by closing Valves 212-2 and 213-2, located upstream and downstream, respectively, of the rupture site.

CGT personnel made a telephonic notification of this rupture to the National Response Center (NRC) [No. 999450] at 9:15 p.m. on January 2, 2012, and made an email notification to the Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, Southern Region at 9:39 p.m. on the same day.

A metallurgical analysis completed by Det Norske Veritas (U.S.A.), Inc. (DNV) concluded that Line 200 actually suffered two distinct but related events: (1) an initial *High Energy Rupture* followed very shortly thereafter by (2) a *Low Energy Failure.*

The *High Energy Rupture* was the result of a failed pipe buckle. The DNV metallurgical report indicated that ground movement along the slope on which the Line 200 pipeline was constructed may have (over time) exerted the stresses necessary to buckle and rupture Line 200. The DNV report also indicated that the *High Energy Rupture* created the stresses necessary to fail a nearby pre-existing girth weld cold crack resulting in the *Low Energy Failure*.

Geotechnical investigations and analyses were performed after the rupture, including a visual survey of CGT's 80-mile right-of-way (ROW) between the Clementsville and Stanton compressor stations. These geotechnical investigations and analyses confirmed that the topography and geology of the ROW, coupled with higher than normal precipitation in 2011, reasonably contributed to the January 2, 2012, rupture.

System Details

Columbia Gulf Transmission Company (CGT) is owned by NiSource Inc. (NiSource), an energy holding company headquartered in Merrillville, Indiana. NiSource's subsidiaries provide natural gas, electricity, and other products and services to approximately 3.8 million customers from the Gulf Coast, through the Midwest, to New England.[1] NiSource operates three distinct business segments: natural gas distribution, natural gas transmission and storage, and electric operations.

A subsidiary of NiSource, the Columbia Pipeline Group (CPG)[2] is headquartered in Houston, Texas. CPG manages NiSource's natural gas transmission and storage operations. CGT, a company within CPG, operates approximately 3,400 miles of interstate natural gas transmission pipelines. CPG also includes the following natural gas pipeline and storage companies:

- Columbia Gas Transmission
- Crossroads Pipeline
- Hardy Storage Company
- Millennium Pipeline

The CGT natural gas pipeline system originates along the Gulf Coast of the United States, and transports natural gas through Louisiana, Mississippi, Tennessee, and Kentucky (Appendix A, Figure1). 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 NiSource company, Columbia Gas Transmission. The CGT pipeline system consists of three transmission pipelines as follows:

- Line 100, 30-inch outside diameter, maximum allowable operating pressure (MAOP) of 935 psig
- Line 200, 30-inch outside diameter, MAOP of 1,008 psig
- Line 300, 36-inch outside diameter, MAOP of 1,008 psig

Events Leading up to the Failure

At approximately 7:00 p.m. Eastern Standard Time (EST),[3] January 2, 2012, a CGT employee at the Stanton Compressor Station observed a pressure drop on the suction side of Line 200. At 7:10 p.m., CGT received calls from residents reporting a fire on what they believed was a CGT pipeline. At 7:15 p.m., CGT confirmed a rupture on its Line 200 pipeline. The Stanton Compressor Station is approximately 12 miles north (downstream) of the rupture location.

The Line 200 rupture occurred at milepost (MP) 68.3 in Hargett, Kentucky (Estill County) in a Class 1 location; approximately 800 feet north of where the pipeline crosses Kentucky Highway 89 (Winchester Road). The rupture occurred between the Clementsville Compressor Station (upstream of the rupture) and the Stanton Compressor Station (downstream of the rupture).

In this area, CGT has three parallel pipelines (Lines 100, 200 and 300). Line 200 and Line 300 were constructed on a sloped portion of the pipeline right-of-way (ROW). Line 300 is the uppermost pipeline in the ROW. Line 200 is downslope approximately 50 feet from Line 300. Line 100 is located at the toe of the slope, approximately 165 feet downslope of Line 200. The force of the rupture did not affect either Line 100 or Line 300.

[1] From the Thomson Reuters, Reuters.com website
[2] Formerly NiSource Gas Transmission & Storage or NGT&S
[3] All times in this report are Eastern Standard Time

At the time of the rupture, Line 200 had an MAOP of 1,008 psig. The approximate operating pressure of the pipeline at the rupture location was 909 psig, which CGT estimated based on the upstream discharge pressure out of Clementsville Compressor Station (911 psig) and the downstream suction pressure into Stanton Compressor Station (899 psig). The CGT calculated potential impact radius (PIR)[4] for Line 200 at the point of rupture was 657 feet. The pipe that failed had the following specifications:

- Manufacturer and year: United States Steel Corp. (U.S. Steel), 1965
- Outside diameter: 30-inches
- Wall Thickness: 0.323-inches
- Specified Minimum Yield Strength (SMYS): 65,000 psi
- Longitudinal seam type: Double-submerged arc weld (DSAW)
- Coating: Coal tar wrapped with Kraft paper

Emergency Response

After CGT's Monitoring Center and Gas Control confirmed the Line 200 rupture, CGT deployed personnel to the Stanton and Clementsville compressor stations to close all the Line 200 valves required to isolate the compressor stations from the ruptured pipeline. The flowing gas was rerouted through Lines 100 and 300.

CGT also deployed personnel to close Line 200 main line valves 212-2 and 213-2 located upstream and downstream of the rupture, respectively. Both valves were approximately 4.4 miles from the rupture.

Approximately 30 people were evacuated from their homes. While no one was injured as a direct result of the pipeline rupture, some sustained minor injuries during the evacuation. There were no fatalities.

Local authorities blocked-in a total of 1.3 miles of Kentucky Highway 89 (Winchester Road) until the fire fighters extinguished the fire. The highway was blocked from its intersection with Kentucky Highway 82 (New Fox Road) south of the rupture to its intersection with Old Fox Road north of the rupture.

CGT personnel made a telephonic notification of this rupture to the National Response Center (NRC) [No. 999450] (Appendix B) at 9:15 p.m. on January 2, 2012, and made an email notification to the Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, Southern Region (OPS Southern Region), at 9:39 p.m. on the same day.

Operator's Actions After the Rupture

One day after the rupture (January 3, 2012), CGT evaluated and surveyed its Line 100 and Line 300 between the Clementsville and Stanton compressor stations to ensure the pipelines were not impacted by the rupture. Line 100 and Line 300 run parallel to and share the ROW with Line 200.

Specifically, CGT performed the following actions to assure the integrity of Line 100 and Line 300:

- Conducted a foot-patrol and a leakage survey in the immediate area of the Line 200 rupture and confirmed no leaks or depth of cover concerns along Lines 100 and 300.
- Conducted a foot-patrol and a leakage survey on Line 100 and Line 300 from main line valve 212-2 to main line valve 213-2 (approximately 9 miles of pipe) and confirmed no leaks or depth of cover concerns.

[4] The PIR is the radius of a circle such that, within this circle, the failure of a pipeline could have significant impact on people or property and is determined by 0.69 x SQRT (PD^2). P=MAOP, D= OD of the line pipe

- Performed an aerial patrol and instrumented leakage survey via helicopter of Line 100 and 300 and confirmed no leaks or depth of cover concerns.

During the initial response to the rupture, CGT isolated Line 200 by closing main line valves 212-2 and 213-2. CGT discovered that valve 213-2 was leaking shortly after closure and consequently extended the downstream isolation point beyond this failed valve to the Stanton Compressor Station valves. It should be noted that CGT did not close any valves on Lines 100 and 300 because these pipelines continued to transport natural gas.

Summary of Return-to-Service

Shortly after the Line 200 rupture, CGT contracted Det Norske Veritas (U.S.A.), Inc. (DNV) to begin a metallurgical analysis of the failed pipeline. DNV arrived at the rupture site on January 4, 2012, and collected general failure site information, measured expelled pipe distances from the rupture area, and advised CGT on which pipe pieces to preserve and deliver to the DNV laboratory. After CGT cut out the required pipe sections for delivery to DNV, it initiated the pipeline repair.

Pipe Repair

CGT repaired the pipeline by replacing approximately 160 feet[5] of pipe with two new pipe sections having the following specifications.

Berg Pipe

- Outside diameter: 30-inches
- Manufacturer and year: Berg Steel, 2009
- Wall Thickness: 0.500-inches
- SMYS: 70,000 psi
- Longitudinal seam type: Submerged arc weld (SAW)
- Length: Approximately 60 feet

Kawasaki Pipe

- Outside diameter: 30-inches
- Manufacturer and year: Kawasaki Steel, 2008
- Wall Thickness: 0.375-inches
- SMYS: 65,000 psi
- Longitudinal seam type: Submerged arc weld (SAW)
- Length: Approximately 100 feet

CGT also replaced main line valve 213-2 while Line 200 was out of service. As stated above, valve 213-2 leaked after CGT personnel closed it during the emergency response to this rupture.

CGT welded, X-rayed, and hydrostatically pressure tested the joints of Berg pipe separately from the joints of Kawasaki pipe. CGT then "tie-in" welded each new section of pipe to the existing Line 200 and then X-rayed the tie-in welds.

Return-to-Service

CGT prepared Line 200 for a return-to-service by performing the following:

- Purged the pipeline of air between valve 212-2 and the new valve 213-2
- Introduced natural gas into the pipeline by increasing the pressure in 200 psig increments

[5] 160 feet is the sum of the expelled pipe pieces' lengths plus the lengths of removed pipe unaffected by the fire

- Performed an instrumented leakage survey between valves 212-2 and 213-2 after each pressure increment
- Increased pressure to 720 psig (maximum)
- Ran a cleaning pig from Clementsville Compressor Station to Stanton Compressor Station to remove debris associated with the new pipe replacement and the new valve 213-2 installation

Once CGT restarted Line 200, it maintained a pressure of 720 psig or less until the OPS Southern Region granted CGT approval to increase the Line 200 pipeline pressure to its original MAOP of 1,008 psig.

Integrity Assurance Plan

In its final metallurgical report, DNV stated that Line 200 had failed at a pipe buckle possibly due to stresses from land movement over time. The location of Line 200 on the side of a hill possibly exposed "*the pipeline to side loading and/or top loading from lack of pipe support*." That is, land movement caused by soil sliding downhill over-stressed the pipeline.

Accordingly, CGT developed and presented to the OPS Southern Region an *Integrity Assurance Plan (IAP)* for Line 200 that also paid particular attention to Line 300 because it was constructed on the same slope as Line 200 and was approximately 50 feet east (upslope) of Line 200. Line 300 would likely have been subjected to the same land movement stresses as Line 200. Line 100, on the other hand, was constructed at the toe of the slope approximately 165 feet west (downslope) of Line 200 and would have been less affected by the land movement.

The IAP included a 20-percent voluntary pressure restriction on Line 200 between the Clementsville Compressor Station and the Stanton Compressor Station; effective after CGT repaired the pipeline and returned it to service. In addition to the pressure restriction, CGT developed three elements to its IAP based on the DNV metallurgical findings and committed to keeping the pressure restriction in place until it completed the following three integrity assurance items:

1. CGT excavated and visually examined approximately 90 feet of Line 300 in the area of the rupture to assess the external pipe conditions. After removing the overburden (soil), CGT measured and observed that Line 300 pipe movement was insignificant. CGT also found no mechanical damage, buckling, wrinkles, coating damage, girth weld, or seam weld anomalies. CGT repaired small randomly located coating holidays.
2. CGT performed an in-line inspection (ILI) of Line 200 using a caliper/deformation tool equipped with an inertial measurement unit (IMU) to assess the integrity of Line 200 from the Clementsville Compressor Station to the Stanton Compressor Station. The caliper/deformation tool vendor's final report revealed two locations along Line 200 that possibly contained wrinkle bends or dents.
    a. CGT excavated the first location and found several "flat" spots on the outside of the pipe, which indicated the location of pipe bending machine "shoes" from the original construction of the pipeline. CGT determined that these flat spots posed no integrity threat to the pipeline.
    b. CGT excavated the second location and observed a 3-degree wrinkle bend in an over-bend configuration. The wrinkle bend was composed of 14 wrinkles (ripples) over a 7-foot span of pipe. CGT removed approximately 11 feet of the external coating and performed a wet magnetic particle inspection of the 11-foot length of pipe over its entire circumference. CGT also radiographed the entire area where the ripples were found. CGT measured each ripple (crest to peak) and using the criteria in *ASME B31.8 (2010) Gas Pipeline Ripples Dents and Corrosion Defects Calculation Module*, evaluated each ripple to determine if it exceeded the maximum height recommended by the module. CGT found no indications or deformities from the wet

magnetic particle inspection and also determined that all 14 ripples were of acceptable height and required no repairs. CGT then recoated the pipeline.

3. CGT contracted GAI Consultants, Inc. to perform a geotechnical analysis of the immediate rupture area and contracted Terracon Consultants, Inc. to perform a geotechnical analysis of the CGT ROW between the Clementsville Compressor Station and the Stanton Compressor Station that included a supplemental analysis of a landslide at MP 68.1.[6]

Follow-on Activities

CGT used the ILI/IMU information to map the anomaly indications and to assist in monitoring any future ground movement effects on Line 200 by creating a baseline for future ILI/IMU run comparisons to be used in pipe bending strain analyses.

As recommended by GAI and Terracon, CGT installed slope monitoring devices at MP 68.1, which was the location of the active ground movement. Terracon installed the devices on May 18, 2012, and CGT now monitors these devices for ground movement at an interval established by Terracon.

CGT has scheduled a follow-up ILI that will include a caliper/deformation tool and an IMU, to be completed by the end of calendar year 2014. CGT will compare the 2014 run data with the 2012 run data to detect possible pipeline deformations and to identify strain features along the Line 200 pipeline possibly caused by land movement.

On April 10, 2012, CGT requested the OPS Southern Region's approval to return the isolated segment of Line 200 the full MAOP of 1,008 psig. The OPS Southern Region recognized that CGT had successfully completed the initial work elements of its *Integrity Assurance Plan* and had developed adequate follow-on actions as part of its plan. Accordingly, on April 13, 2012, the OPS Southern Region granted CGT approval to increase the Line 200 pipeline pressure to its original MAOP of 1,008 psig.

Findings and Contributing Factors

Metallurgical Analysis

CGT contracted the metallurgical analysis to Det Norske Veritas (U.S.A.), Inc. (DNV).[7] According to DNV's final report, *Metallurgical Analysis of Pipe Sections from Line Segment ML 200 that Failed in Service* (Metallurgy Report) (Appendix C), Line 200 appeared to have initially failed and ruptured as a single event, but the DNV report described the pipeline as having failed at two separate locations along the pipe, at two distinct moments, due to two different failure modes. The report did not provide or estimate the time between the two failures because that was indeterminable. Specifically, DNV categorized the Line 200 rupture/failure event as follows:

1) *High-Energy Rupture,* and

2) *Low-Energy Failure*

High-Energy Rupture Analysis

The High-Energy Rupture of Line 200 occurred in a pipe buckle between the 10 o'clock and 3 o'clock pipe positions. The buckle was within a pipe segment that contained a field fabricated side bend/under bend. The pipeline was originally constructed in the 1960s on the side of a hill and DNV concluded that

[6] The results of each analysis are discussed in the *Findings and Contributing Factors* section of this failure investigation report.
[7] DNV submitted the final report on this failure March 28, 2012

ground movement along the hillside may have exerted the stresses necessary to create the pipe buckle on the side bend/under bend area of the pipe.

DNV determined the origin of the high-energy rupture was near a girth weld in an area of what appeared to be circumferential expansion caused by the pipe buckle and explained the role of the pipe buckle in this rupture:[8]

"The results of the analyses indicate that the high-energy rupture initiated near a field weld in an area of circumferential pipe expansion, likely due to buckling...The rupture occurred at one of the peaks in the buckle and the mode of crack propagation was ductile tearing...The location of the failure (i.e. on the side of the hill) and the surrounding terrain are consistent with possible exposure of the pipeline to side loading and/or top loading from lack of support."

Low-Energy Failure Analysis

DNV concluded the high-energy rupture occurred initially and that the resultant axial stresses from the force of the high-energy rupture acted on the existing girth weld crack described above, which resulted in the low-energy failure. That is, DNV concluded that a pre-existing crack[9] located in a girth weld at Station Number 3609+26 initiated the low-energy failure of Line 200 after, and as a result of, the high-energy rupture. DNV discovered additional pre-existing cracks in the girth weld ranging from 1½ -inches to 12-inches in circumferential length. The cracks originated from the inside diameter surface at the toe of the root pass weld[10] in the heat-affected zone. The maximum depth of the pre-existing cracks was 0.197- inches, which was 42.8% of the pipe weld thickness. DNV further stated the morphology of these cracks was typical of hydrogen-assisted cold[11] cracking as supported by the following evidence:

1. A relatively high carbon equivalent (CE) of the line pipe steel
   a. The CEs of the upstream and downstream pipe joint from the failed girth weld were 0.46 and 0.51, respectively. At the time of this pipe manufacture, the API 5L[12] standard did not specify a carbon equivalent limit. The current edition of API 5L[13] sets a CE limit of 0.43 for the same grade of line pipe that failed.

2. The mixed mode cracking on the fracture surfaces
   b. During the failure, the crack propagation occurred in the weld metal, and to a lesser degree through the parent metal.

Geotechnical Analysis 1

On January 6, 2012, CGT contracted GAI Consultants, Inc. (GAI) to assess the geotechnical conditions of the January 2, 2012, rupture area. Specifically, CGT requested GAI to survey the rupture area for evidence of land movement and to identify potential geotechnical threats to Line 300 that is approximately 50 feet east (upslope) of Line 200. However, by January 6, 2012, the Line 200 pipeline

[8] *Det Norske Veritas Final Report, NiSource Gas Transmission and Storage, Metallurgical Analysis of Pipe Sections from Line Segment ML 200 that Failed in Service*, dated March 28, 2012
[9] The term "pre-existing crack" denotes a crack or cracks that existed within the weld prior to the January 2, 2012 failure.
[10] The root pass weld is the first layer of a multi-pass weld.
[11] The term "cold cracking" denotes a crack that occurred after the weld metal has cooled to ambient temperature versus a hot cracking that occurs at elevated temperatures - neither cracking is the result of service loads
[12] API 5LX Specification for Line Pipe 12th Edition, 1965
[13] API 5L, Specification for Line Pipe 44th Edition, 2007, includes errata (January 2009) and addendum (February 2009, Table 5

repair efforts were underway and these efforts had disturbed most areas GAI considered for its geotechnical study. The pipeline repairs notwithstanding, GAI surveyed various locations along the CGT ROW within the rupture area, and noted in its written report to CGT (Appendix D) either, *"no visible indications of slope movement"* or *"due to the disturbance in the area...could not be visually evaluated for signs of slope movement."*

GAI also reviewed aerial photographs of the rupture area that were taken immediately after the rupture by CGT prior to the Line 200 pipeline repair. GAI observed a soil bulge toward the northern edge of the area with some "*slight irregularity"* continuing to the south, which ended in the vicinity of the rupture. GAI reported the following,

"Based on the topographical layout of the [Line 200 pipeline] *right-of-way, the soils along the right of way are anticipated to be thin (less than 10 feet) overlying rock. Heavy precipitation events may have perched water in the soil on the rock, reducing strength characteristics of the soil, thus causing the soil to creep. The soil creep may have subjected the pipeline to some lateral loading."*

GAI concluded its analysis by recommending a ground movement monitoring program to be conducted along the Line 200/Line 300 pipeline right-of-way.

Geotechnical Analysis 2

On January 13, 2012, CGT contracted Terracon Consultants Inc. to conduct a more extensive assessment of the geotechnical conditions along the CGT 80-mile pipeline right-of-way from Clementsville Compressor Station to Stanton Compressor Station. The objectives of this assessment were to:

- Visually survey the CGT pipeline ROW between Clementsville Compressor Station and Stanton Compressor Station to review the ground surface conditions, paying particular attention to the obvious indicators of ground movement,
- Identify and describe areas of interest, problem areas and potential causes,
- Review the precipitation data for the area; and,
- Report other regional events of the area that may cause topographic changes.

Terracon accomplished these objectives by completing the following:

- Examining Kentucky's physiographic regions within the CGT ROW
- Reviewing the precipitation data from weather stations in the vicinity of CGT's ROW between Clementsville, KY and Stanton, KY
- Reviewing seismic activity records for 2008 through 2012, approximately 180 mile radius of MP 40
- Completing a visual inspection of the CGT ROW topography by walking and driving an all-terrain vehicle along the ROW from the Clementsville Compressor Station to the Stanton Compressor

<u>Physiographic Regions</u>

In its final report titled, *Geotechnical Survey Data Report, Visual Survey of CGT Pipeline Right of Way, Clementsville, Casey County to Stanton, Powell County, Kentucky* (ROW Survey) (Appendix E), Terracon described the CGT pipeline ROW from the Clementsville Compressor Station to the Stanton Compressor Station as passing through the following physiographic regions:

- Bluegrass
- Eastern Knobs (The Knobs Region forms a crescent separating the Bluegrass Regions from the Eastern Coal Field Region and is named for its characteristic conical and flat-topped hills)
- Pottsville Escarpment
- Cumberland Plateau

The majority of Estill County including the location of the January 2, 2012, rupture is located in the Cumberland Plateau region with a smaller portion of the county located in the Eastern Knobs and Pottsville Escarpment regions. Terracon described the terrain of the Cumberland Plateau as follows: *"Most of the terrain in the Cumberland Plateau is steeply sloping. The slopes are underlain by shale and sandstone and the surfaces are littered with accumulations of rock fragments and colluvium that are susceptible to down slope movements by debris avalanche, landslide, creep, and sheet wash. Overburden soil depths are typically shallow."*

Precipitation

Terracon reviewed precipitation data from weather stations in the vicinity of the CGT ROW, and discovered higher than normal precipitation levels for 10 of the 12 months in 2011.

Terracon calculated the higher than normal levels by first establishing a *"normal average"* precipitation level by averaging the monthly precipitation totals between 2008 and 2012, then comparing the actual precipitation level for a given month in 2011 against the "*normal average*." For example, the CGT ROW area[14] experienced a precipitation increase to 11-inches from a normal average of 4-inches during the month of April 2011 - an increase of 175 percent for the month of April when compared to its average over the previous 3 years. Terracon reported the following, regarding the effects of water on the topography and its contribution to land movement, *"Water...increases the driving force and reduces the resisting forces. Water flowing through the saturated hillsides creates seepage forces that reduce the shear strength of the cohesive soils."*

Seismic Activity

Terracon reviewed seismic activity data for Kentucky inside a 180-mile radius of MP 40, and discovered 26 earthquake events ranging from 58 miles to 173 miles from the MP 40 reference point. Terracon noted in its report that the most recent earthquake in Kentucky was of 2.4 magnitude occurring near Livermore, KY on September 19, 2011. The epicenters for all 26 earthquakes were not located in Kentucky.

Visual Inspection

Terracon's visual inspection of the CGT ROW between Clementsville Compressor Station and Stanton Compressor Station included the review of the following:

- Creek and drainage ditch crossings: Terracon noted the condition of the creeks and drainage areas along the ROW, and the existence and appearance of exposed pipelines.
- Sinkholes and surface depressions: Terracon noted the location and depth of each sinkhole and surface depression along the CGT ROW.
- Slope instability: Terracon's most significant finding related to its observation of slope instability along the CGT ROW. This was significant because slope instability, i.e., ground movement, correlated directly with the DNV metallurgical finding of ground movement contributing to Line 200 failure and rupture on January 2, 2012.

Slope Instability Observation

In its final report to CGT, Terracon listed 60 occurrences of slope instability it observed along the CGT ROW between the Clementsville Compressor Station and Stanton Compressor Station. The instability ranged from eroded/washed-out areas at non-vegetated slopes to signs of past landslides and/or creep movement. The most severe occurrence Terracon noted in its report was a landslide at MP 68.1, which

[14] For this report, the CGT ROW area is between Clementsville Compressor Station and Stanton Compressor Station

was approximately 1,100 feet upstream of the January 2, 2012, rupture centerline.[15] (Appendix A, Figure 14)

At this location, Terracon discovered visible head-scarps, toe bulges, and other topographic features indicative of a previous landslide. Terracon analyzed this landslide in a separate report titled, *Slope Study at Mile Post 68.1 of CGT 200 ML Pipeline Irvine, Kentucky* (Slope Study) (Appendix F). Terracon described its observation, including a soils analysis as follows:

- *"The landslide [at MP 68.1] affected an area measuring approximately 165 feet by 30 feet downslope of the 200 ML pipeline. Typical subsurface profile at the site consists of pipe trench backfill, and natural cohesive overburden soils with fragments to boulder sized weathered shales and sandstone. As expected, fill soils were encountered in the vicinity of the pipeline due to trenches that would have been excavated to facilitate installation."*
- Terracon's final analysis in the *Causation* section of the Slope Study stated the following:
  "This slope showed signs of being susceptible to creep-type movement based on our observations during site reconnaissance on February 21, 2012...Creep movement of the slope at this site was likely accelerated by the combination of excessively wet weather saturating the overburden soils, undercutting of the toe of the slope along Woodwards creek. The principal driving force in this landslide appears to be water, with saturated soils likely significantly reducing the stability of the slope."

  Geotechnical Summary for MP 68.1

  - Tree trunk distortion at the toe of the slope and leaning fence posts were evidence that this slope was subject to creep type movement.
  - Woodwards Creek was located along the toe of the slope, and undercut the slope bank. This creek was located between Line 200 and Line 100, and ran parallel to the ROW at this location.
  - The higher than normal precipitation discussed above, contributed to the slope movement by saturating the soil, increasing the pore pressure and reducing the soils ability to resist the shearing forces.[16]

Conclusions

- CGT's Line 200 experienced a *High-Energy Rupture* on January 2, 2012, due to failed axial and circumferential cracks in a pipe buckle. The pipe buckle was approximately 3-inches *"high"* and located in the 10 o'clock through 3 o'clock pipe position.
- The DNV metallurgical report indicated the pipe failure origin was near a girth weld in an area of circumferential expansion likely due to the pipe buckle. The pipe failure origin was also near an existing pipe side bend/under bend configurations that DNV believed might have initially facilitated the formation of the pipe buckle.
- The DNV metallurgical report stated that because Line 200 was located on a hillside slope, the pipe buckle was likely formed by bending stresses due to land movement.
- The DNV metallurgical report stated that the *High-Energy Rupture* of Line 200 at the pipe buckle led to a nearly instantaneous *Low-Energy Failure* of a nearby girth weld cold crack. The girth weld cold crack failure was approximately 40 feet upstream from the pipe buckle failure.

[15] For reference, MP 68.1 was south of KY Highway 89/Winchester Road
[16] Due to natural forces such as gravity, seismic activity or various external loads

- CGT used two geotechnical analyses as components of its incident investigation. The initial geotechnical analysis covered the immediate rupture area and the subsequent analysis covered the entire CGT ROW between Clementsville Compressor Station and Stanton Compressor Station.
- While the two geotechnical analyses did not categorically assert that land movement at MP 68.3 caused the pipe to buckle and fail, they did highlight several facts that support the supposition of the metallurgical analysis that "*The location of the failure (i.e. on the side of the hill) and the surrounding terrain are consistent with possible exposure of the pipeline to side loading and/or top loading from lack of support."*
- Terracon noted in its ROW Survey, that the slope that encompassed the Line 200/300 right-of-way in the area of the rupture "*showed signs of being susceptible to creep-type*[17] *movement*" based on its February 2012 site visit.
- Terracon noted in its Slope Study, that the creep-type movement of this slope was likely accelerated by the combination of excessively wet weather saturating the *overburden soils.*[18]
- The area experienced higher than normal precipitation in 2011, and the geotechnical analyses explained that precipitation facilitates the "creep" and all facets of land movement.
- The Line 200 right-of-way is in a physiographic region where ground movement would be expected.
- The rupture area contained the geology and topography consistent with land movement.

[17] Creep-type movement indicates long-term movement or wasting.
[18] Overburden soils indicate the soils above the bedrock horizon

Appendices

A Map and Photographs

B NRC Report

C Det Norske Veritas report, *Metallurgical Analysis of Pipe Sections from Line Segment ML 200 that Failed in Service*, dated March 28, 2012

D GAI Consultants, Inc. report, *Ground Movement Assessment* dated January 13, 2012

E Terracon Consultants, Inc. report, *Geotechnical Survey Data Report, Visual Survey of CGT Pipeline Right of Way, Clementsville, Casey County to Stanton, Powell County, Kentucky,* dated March 23, 2012

F Terracon Consultants, Inc. report *Geotechnical Engineering Report, Slope Study at Mile Post 68.1 of CGT 200 ML Pipeline Irvine, Kentucky,* dated March 23, 2012

G Operator's Final Incident Report to PHMSA (PHMSA F 7100.2)

Failure Investigation Report
Columbia Gulf Transmission
Line 200 Rupture in Estill County, Kentucky

Failure Date - January 2, 2012

Appendices (Redacted Appendices are on File at PHMSA)

A Map and Photographs

B NRC Report

C (Redacted) Det Norske Veritas report, *Metallurgical Analysis of Pipe Sections from Line Segment ML 200 that Failed in Service*, dated March 28, 2012

D (Redacted) GAI Consultants, Inc. report, *Ground Movement Assessment* dated January 13, 2012

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F (Redacted) Terracon Consultants, Inc. report *Geotechnical Engineering Report*, *Slope Study at Mile Post 68.1of CGT 200 ML Pipeline Irvine*, *Kentucky*, dated March 23, 2012

G Operator's Final Incident Report to PHMSA (PHMSA F 7100.2)

Appendix A

Figure 1. Columbia Gulf Transmission Company System Map

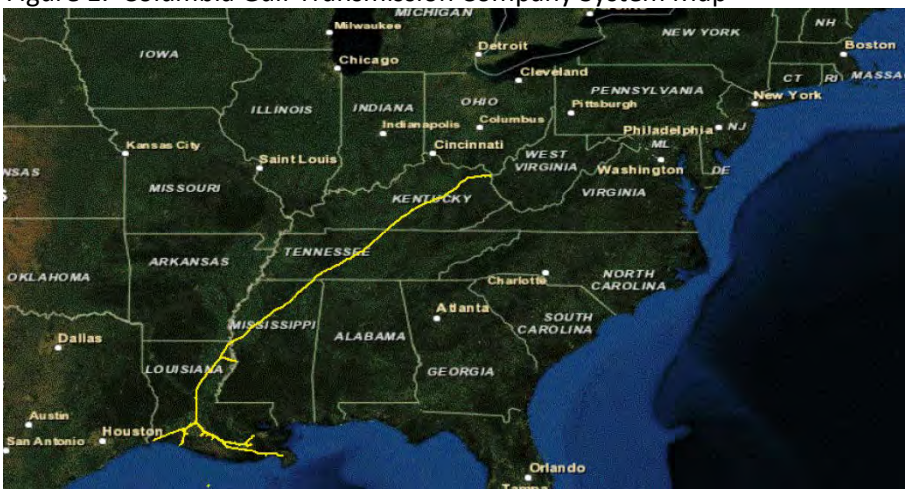

Figure 2. Blue marker indicates the Rupture Location

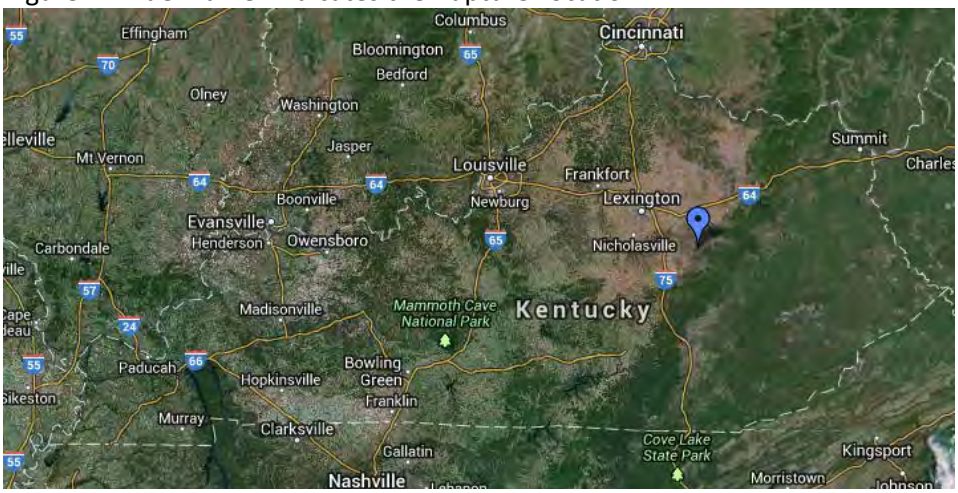

Figure 3. Blue marker indicates the Rupture location

Appendix A

Figure 4. Map showing the area affected by the rupture

Appendix A

Figure 5. Burned vegetation at Line 200 rupture location

Figure 6. Bottom left of photograph is downstream pipeline failure terminus. The middle/far right of photograph is the upstream pipeline failure terminus

Appendix A

Figure 7. Downstream terminus – High Energy Rupture

Figure 8. High Energy Rupture section

Appendix A

Figure 9. Low Energy Failure pipe section

Figure 10. Low Energy Failure pipe section – fractured pipe portion shown mates to the High Energy Rupture section

Appendix A

Figure 11. Clean fracture in the girth weld at the upstream pipe terminus – this was location of the Low Energy Failure origin

Figure 12. Line 200 looking downstream – The offset between the upstream and downstream termini necessitated the over bend and side bend during the original construction

Appendix A

Figure 13. Trailer located over 800 feet from the rupture centerline, south of KY Highway 89 (Winchester Road)

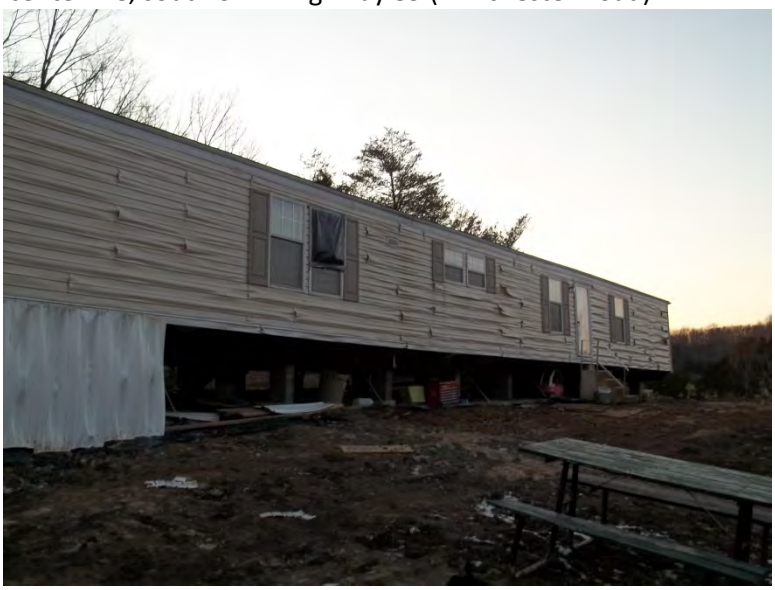

Figure 13. Closer view of heat damage – the yellow tape indicates the location of Line 200 pipe piece expelled from rupture area

Appendix A

Figure 14. The top right marker indicates the January 2, 2012 rupture location centerline at MP 68.3, the bottom left marker indicates the location of a small land slide discovered by Terracon Consultants, Inc. at MP 68.1

APPENDIX B

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

Incident Report # 999450

INCIDENT DESCRIPTION

***Report taken at 21:15 on 02-JAN-12**
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
The incident occurred on 02-JAN-12 at 19:50 local time.
Affected Medium: AIR

SUSPECTED RESPONSIBLE PARTY

Organization: COLUMBIA GAS TRANSMISSION
CHARLESTON, WV 25314

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

EXACT LOCATION IS UNKNOWN County: POWELL
City: STANTON State: KY

BETWEEN POWELL AND ESTILL COUNTIES

RELEASED MATERIAL(S)

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

DESCRIPTION OF INCIDENT

A FLAME WAS OBSERVED IN THE VICINITY OF A PIPELINE WHICH WOULD INDICATE A RELEASE OF NATURAL GAS.
NEARBY PRIVATE CITIZENS HAVE BEEN EVACUATED.

INCIDENT DETAILS

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

DAMAGES

Fire Involved:	**YES**	**Fire Extinguished: NO**			
INJURIES:	**NO**	**Hospitalized:**	**Empl/Crew:**	**Passenger:**	
FATALITIES:	**NO**	**Empl/Crew:**	**Passenger:**	**Occupant:**	
EVACUATIONS:	**YES**	**Who Evacuated:**	**PRIVATE CITIZENS**	**Radius/Area:**	
Damages:	**NO**				

Closure Type		Description of Closure	Length of Closure	Direction of Closure
Air:	**N**			
Road:	**N**			
Waterway:	**N**			
Track:	**N**			
Major Artery:	**N**			

APPENDIX B

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

REMEDIAL ACTIONS

FIRE AND POLICE ON SCENE/ EMERGENCY VALVES HAD BEEN SHUT/ GAS WILL BURN OFF
Release Secured: UNKNOWN
Release Rate:
Estimated Release Duration:

WEATHER

Weather: SNOWY, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: NONE
State/Local On Scene: POLICE/ FIRE
State Agency Number: NONE

NOTIFICATIONS BY NRC

ATLANTIC STRIKE TEAM (MAIN OFFICE)
02-JAN-12 21:21
USCG ICC (ICC ONI)
02-JAN-12 21:21
CGIS RAO ST. LOUIS (COMMAND CENTER)
02-JAN-12 21:21
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
02-JAN-12 21:21
EPA OEM (MAIN OFFICE)
02-JAN-12 21:25
EPA OEM (AFTER HOURS SECONDARY)
02-JAN-12 21:25
U.S. EPA IV (MAIN OFFICE)
02-JAN-12 21:22
EPA IV KENTUCKY (MAIN OFFICE)
02-JAN-12 21:21
FEDERAL EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
02-JAN-12 21:21
USCG NATIONAL COMMAND CENTER (MAIN OFFICE)
02-JAN-12 21:22
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
02-JAN-12 21:21
NOAA RPTS FOR KY (MAIN OFFICE)
02-JAN-12 21:21
NATIONAL RESPONSE CENTER HQ (MAIN OFFICE)
02-JAN-12 21:23
HOMELAND SEC COORDINATION CENTER (MAIN OFFICE)
02-JAN-12 21:21
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
02-JAN-12 21:21
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY WEEKDAYS (VERBAL))
02-JAN-12 21:23
KY DEP/ERT (MAIN OFFICE)
02-JAN-12 21:21
KY DEP/ERT (DUTY OFFICER)
02-JAN-12 21:21
USCG DISTRICT 8 (MAIN OFFICE)
02-JAN-12 21:21

ADDITIONAL INFORMATION

NONE.

*** END INCIDENT REPORT # 999450 ***

Appendix C

DET NORSKE VERITAS™

Final Report

Metallurgical Analysis of Pipe Sections from Line Segment ML 200 that Failed in Service

NiSource Gas Transmission and Storage
Houston, Texas

Report No./DNV Reg No.: ANEUS813KKRA (PP031516)
March 28, 2012

APPENDIX G

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:**	01/27/2012
	No.	20120011 - 15883 (DOT Use Only)

INCIDENT REPORT - GAS TRANSMISSION AND GATHERING PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 10 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

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

PART A - KEY REPORT INFORMATION

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

Last Revision Date:	04/09/2013
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:	01/02/2012 19:50
5. Location of Incident:	
Latitude:	37.792666
Longitude:	-84.02975
6. National Response Center Report Number (if applicable):	999450
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	01/02/2012 21:15
8. Incident resulted from:	Reasons other than release of gas
9. Gas released: (select only one, based on predominant volume released)	
- Other Gas Released Name:	
10. Estimated volume of commodity released unintentionally - Thousand Cubic Feet (MCF):	206,923.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	14,202.00
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	01/02/2012 21:15
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:	30
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	
19b. Local time operator resources arrived on site	

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:	40336
4. City	Irvine
5. County or Parish	Estill
6. Operator designated location	Milepost/Valve Station
Specify:	68.3
7. Pipeline/Facility name:	Line 200
8. Segment name/ID:	Between VS 212-2 and 213
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):	38
12. Did Incident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
Name of body of water (If commonly known):	
Approx. water depth (ft) at the point of the Incident:	
Select:	
If Offshore:	
13. Approx. water depth (ft) at the point of the Incident:	
14. Origin of Incident:	
- If "In State waters":	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- If "On the Outer Continental Shelf (OCS)":	
- Area:	
- Block #:	
15. Area of Incident:	

PART C - ADDITIONAL FACILITY INFORMATION

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

3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	65,000
3d. Pipe specification:	API 5L
3e. Pipe Seam – Specify:	DSAW
- If Other, Describe:	
3f. Pipe manufacturer:	US Steel
3g. Year of manufacture:	1965
3h. Pipeline coating type at point of Incident – Specify:	Coal Tar
- If Other, Describe:	
- If Weld, including heat-affected zone – Specify:	
- If Other, Describe:	
- If Valve – Specify:	
- If Mainline – Specify:	
- If Other, Describe:	
3i. Mainline valve manufacturer:	
3j. Year of manufacture:	
- If Other, Describe:	
4. Year item involved in Incident was installed:	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:	
Approx. size: in. (widest opening):	
by in. (length circumferentially or axially):	
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Class Location of Incident:	Class 1 Location
2. Did this Incident occur in a High Consequence Area (HCA)?	No
- If Yes:	
2a. Specify the Method used to identify the HCA:	
3. What is the PIR (Potential Impact Radius) for the location of this Incident? Feet:	657
4. Were any structures outside the PIR impacted or otherwise damaged due to heat/fire resulting from the Incident?	Yes
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	$ 100,000
7b. Estimated cost of Operator's property damage & repairs	$ 902,000
7c. Estimated cost of Operator's emergency response	$ 0
7d. Estimated other costs	$ 5,000
Describe:	Misc.
7e. Total estimated property damage (sum of above)	$ 1,007,000
Cost of Gas Released	
7f. Estimated cost of gas released unintentionally	$ 637,323
7g. Estimated cost of gas released during intentional and controlled blowdown	$ 43,742
7h. Total estimated cost of gas released (sum of 7.f & 7.g above)	$ 681,065

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	909.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	1,008.00
3. Describe the pressure on the system or facility relating to the	Pressure did not exceed MAOP

Incident:	
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):	46,464
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No – Which physical features limit tool accommodation? *(select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No
- If Yes, which operational factors complicate execution? *(select all that apply)*	
- Excessive debris or scale, wax, or other wall build-up	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other	
- If Other, Describe:	
5f. Function of pipeline system:	Transmission System
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Incident?	Yes
- If Yes:	
6a. Was it operating at the time of the Incident?	Yes
6b. Was it fully functional at the time of the Incident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
7. How was the Incident initially identified for the Operator?	SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations)
- If Other – Describe:	
7a. If "Controller", "Local Operating Personnel, including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 7, specify the following:	
8. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Incident?	No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: (provide an explanation for why the Operator did not investigate)
- If No, the operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	The cause of the failure was not related to the control room or the controllers since the system was operating normally and below its MAOP at the time of the incident.
- If Yes, Describe investigation result(s) *(select all that apply)*:	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the operator), and other factors associated with fatigue	

- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue	
- Provide an explanation for why not:	
- Investigation identified no control room issues	
- Investigation identified no controller issues	
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above –	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Incident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	Yes
- If Yes:	
1a. Describe how many were tested:	3
1b. Describe how many failed:	0
2. As a result of this Incident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Describe how many were tested:	
2b. Describe how many failed:	

PART G - APPARENT CAUSE

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

Apparent Cause:	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 inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
14. Has one or more internal inspection tool collected data at the point of the Incident?	
14a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage Tool	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
If Other, Describe:	
15. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes,	
Most recent year tested:	
Test pressure (psig):	
16. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	

Most recent year conducted:	
17. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
17a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year examined:	
- Guided Wave Ultrasonic	
Most recent year examined:	
- Handheld Ultrasonic Tool	
Most recent year examined:	
- Wet Magnetic Particle Test	
Most recent year examined:	
- Dry Magnetic Particle Test	
Most recent year examined:	
- Other	
Most recent year examined:	
If Other, Describe:	
G2 - Natural Force Damage - *only one **sub-cause** can be picked from shaded left-handed column*	
Natural Force Damage – Sub-Cause:	Earth Movement, NOT due to Heavy Rains/Floods
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	Subsidence
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Incident generated in conjunction with an extreme weather event?	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 visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption: (hours)	
17. Description of the **CGA-DIRT Root Cause** (*select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, then one predominant second level CGA-DIRT Root Cause as well*):	
- Predominant first level CGA-DIRT Root Cause:	
- If One-Call Notification Practices Not Sufficient, Specify:	
- If Locating Practices Not Sufficient, Specify:	
- If Excavation Practices Not Sufficient, Specify:	
- If Other/None of the Above, Explain:	
G4 - Other Outside Force Damage - only one **sub-cause** can be selected from the shaded left-hand column	
Other Outside Force Damage – Sub-Cause:	
- If Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation:	
- If Electrical Arcing from Other Equipment or Facility:	
- If Previous Mechanical Damage NOT Related to Excavation:	
Complete Questions 3-7 ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Incident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other:	
Most recent year run:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted	

since original construction at the point of the Incident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident :	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
If - If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	

G5 - Pipe, Weld, or Joint Failure	**Use this section to report material failures ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is "Pipe" or "Weld."**
	Only one **sub-cause** can be selected from the shaded left-hand column

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

APPENDIX G

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

Based on the site evaluation information, aerial photography, the abnormally high rainfall amounts prior to the incident, the appearance of the failed sections and the preliminary report provided by the third party metallurgist, the mostly likely primary cause of the failure was pipe failure due to land movement.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

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