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

Principal Investigator	Michael Yazemboski
Senior Accident Investigator	Michael Yazemboski
Region Director	Byron E. Coy
Date of Report	4/18/2012
Subject	Failure Investigation Report – Columbia Gas Transmission Corp. Artemas Compressor Station

Operator, Location, & Consequences

Date of Failure	11/3/2011
Commodity Released	Natural Gas
City/County & State	Artemas, Bedford County, PA
OpID & Operator Name	2616 Columbia Gas Transmission Corp
Unit # & Unit Name	65901 Artemas A&B Storage Fields
SMART Activity #	136480
Milepost / Location	Latitude: 39.72573 Longitude: -78.4217
Type of Failure	Rupture in 2" drain line on Filter Separator-A
	Cause: Wall thinning due to internal corrosion
Fatalities	None
Injuries	None
Description of area impacted	Class 1 area, rural. Damage was limited to the compressor station and related facilities on station property.
Total Costs	$506,000 property + $53,400 gas = $559,400 estimated total

Executive Summary

On November 3, 2011 at approximately 00:45, an incident occurred at Columbia Gas Transmission's (CGT) Artemas Compressor Station located in Bedford County, PA. The failure resulted in a release of natural gas and subsequent ignition and fire at the Station. Property damage was limited to the compressor station and related facilities and did not impact public property. There were no injuries or fatalities as a result of this incident. The main office structure and several outbuildings were destroyed due to the heat and flames. Supply to customers and deliverability were not impacted.

The incident was caused by the failure of a section of 2" manual drain piping located at the bottom of Filter Separator-A. According to the Failure Analysis conducted by DNV out of Dublin, Ohio, the cause of the failure was due to wall thinning caused by internal corrosion. The failure was located on the pressurized side of the manual dump valve on Filter Separator-A. The pressure in the filter separator at the time of failure was 1,940 psig, which was below the 2,400 psig Maximum Allowable Operating Pressure (MAOP) for this system.

The internal corrosion was caused by fluid collecting and remaining stagnant in the manual dump drain for lengthy periods of time until the dump valve was manually operated and the fluids discharged. The separator was equipped with an automatic dump system which resulted in the manual dump valve only being operated periodically throughout the year. According to the laboratory analysis this stagnant fluid led to internal corrosion which resulted in wall thinning in the failed section of piping. It should be noted that internal corrosion was only identified on the manual dump piping. There were no indications of internal corrosion on other piping associated with the automatic dump system.

System Details

CGT transports an average of 3 billion cubic feet of natural gas per day through a nearly 12,000-mile pipeline network and 92 compressor stations in 10 states, serving hundreds of communities. Their customers include local gas distribution companies, energy marketers, electric power generating facilities and hundreds of industrial and commercial end users. CGT also owns and operates one of North America's largest underground natural gas storage systems that includes 37 storage fields in four states with over 650 billion cubic feet in total capacity.

The Artemas Compressor Station is located in Bedford County, PA near the PA and MD border. The Artemas Compressor Station compresses natural gas for transportation along CGT's Transmission pipelines 1804 (20" diameter) and 10240 (24" diameter). The station also serves to inject and withdraw natural gas from two associated storage fields, Artemas A and B, for transportation along lines 1804 and 10240. These two transmission lines are used provide natural gas to the northeastern United States. These pipelines operate at a Maximum Allowable Operating Pressure (MAOP) of 936 psig while Artemas A and B fields operate at an MAOP of 2,400 psig.

The Artemas Compressor Station consists of two reciprocating 2,000 horsepower Clark compressor engines, two 1,160 horsepower Solar-Saturn Turbines and one 1,350 horsepower Solar-Saturn T-1300 Turbine. The turbine units are primarily used for transmission and the reciprocating units are mainly used to compress gas into and out of the storage fields.

The Artemas Compressor Station was placed into transmission service on November 27, 1970. In 1972, additional equipment was added to the station allowed for the injection and withdrawal of natural gas from the storage field.

A review of the records indicates there have been no reported incidents at this facility since the station was placed into service in November 1972. In addition, there have been no safety related conditions (SRCR) reported involving this facility in the past 7 years.

As a result of the incident that occurred at the station on November 3, 2011, supply and deliverability were not impacted.

Events Leading up to the Failure

During the evening of November 2, 2011, the Artemas Compressor Station was in the process of switching from withdrawing out of storage to injection into storage. At around 17:30, a CGT employee operated a bypass valve, located near Filter Separator-A, allowing the gas to bypass the separator for injection into storage. A review of SCADA records, station operating records and alarm records, show the station was functioning normally up until the time of the incident.

At around 00:30 on the morning of November 3, 2011, a resident who lives approximately 1/4 mile from the station contacted CGT's maintenance mechanic via phone and reported a fire at the station. Based upon interviews conducted during the investigation, it was concluded that the employee's actions did not cause or contribute the incident. At around 00:42, a CGT employee arrived near the station, verified the situation, and contacted Gas Control to shut down the compressor units at the station. At 00:42 Gas control initiated shut down of the compressors. At around 00:46 Gas Control lost communications with Artemas Station.

Emergency Response

CGT's Artemas Compressor Station is equipped with an automatic Emergency Shutdown System. However, since the failure occurred in the station yard outside of the compressor building, the gas detectors and fire sensors did not activate the ESD system automatically. On 11/3/2012, the ESD system was manually activated by CGT personnel at 00:50, approximately 20 minutes after a neighbor reported the fire at the station. A timeline of events is outlined below. All of the events occurred on 11/3/2011.

Time	Event
00:30	A neighbor who lives approximately 1/4 mile southwest of Artemas Compressor Station) called a CGT Maintenance Mechanic – Operations Northeast –Cumberland at his

	residence and reported an incident and fire at the station.
00:35	The CGT Maintenance Mechanic called the CGT Compressor Station Engineer from his driveway and reported that he received a call from a neighbor regarding an incident and fire at Artemas. The CGT Maintenance Mechanic and the CGT Compressor Station Engineer agreed to meet him at the compressor station.
00:37	The CGT Maintenance Mechanic called Gas Control from his driveway and reported that he received a call from a neighbor regarding an incident and fire at Artemas.
00:39	Bedford Fire Department called Gas Control and indicated that they had a report of loud noise at Artemas Station and they were en route (approximately 10 minutes away).
00:42	The CGT Maintenance Mechanic arrived at the top of the mountain on Route 68 and could see the fire and contacted Gas Control and asked Gas Control to shut down the compressor units at Artemas Compressor Station. The CGT Maintenance Mechanic also requested that the CGT Team Leader Operations be informed.
00:42	Gas Control initiates shut off of compressor units at Artemas Compressor Station. Gas control informs the CGT Team Leader Operations who initiates movement towards the station.
00:46	Gas Control loses communications with Artemas Compressor Station.
00:50	The CGT Maintenance Mechanic drives by station and identifies fire originating from the area of the Artemas A filter separator. He proceeds into the station driveway and initiates the shutdown at the station by pulling the emergency shutdown device (ESD) near the front gate of at the station. He then proceeds to a safe location about ½ mile away.
01:02	The CGT Maintenance Mechanic determines that the ESD fails to arrest the fire and proceeds to call and direct the CGT Compressor Station Operator to shut off suction and discharge valves to the station (transmission line valves 1804 and 10240). The CGT Maintenance Mechanic initiates action to shutoff valves on storage field lines to Artemas A and B.
01:09	Gas Control contacts the CGT Principal Engineer – System Integrity regarding the event. The full nature of the event is not known at this time.
01:10	The CGT Compressor Station Operator shuts off valves isolating Artemas from Line 1804. The CGT Maintenance Mechanic contacts 911 and reports a fire at Artemas Compressor Station, and advises that company personnel were onsite and evacuating gas to put out the fire. The CGT Maintenance Mechanic requests that the fire department only secure the perimeter at this time.
01:27	The CGT Maintenance Mechanic reports to Gas Control that the suction and discharge valves to the station are closed. He also reports that personnel are proceeding to shut the ESD supply gas and are manually shutting the wells in.
01:45	The CGT Maintenance Mechanic and the CGT Compressor Station Operator finish closing all of the supply valves to Artemas A field.
02:25	The CGT Compressor Station Operator, CGT Well Tender, the CGT Maintenance Mechanic and the operations team leader finish closing all supply valves to Artemas B field and proceed to the station.
02:45	The CGT Principal Engineer – System Integrity notifies the National Response Center (NRC) regarding the incident (NRC Number 994393).
03:00	The Team Leader – Engineering arrives and available company personnel meet at the parking lot of the local grocery to evaluate the situation. At that time it was determined that conditions were safe to go onsite and manually operate valves, if necessary. Personnel proceed to the Compressor Station.

	The CGT Well Tender and the CGT Compressor Station Engineer proceed to the storage field to verify correct valve positions.
03:15	The CGT Compressor Station Operator manually operates the hydraulic system at the actuator of the ESD valve near the separator to ensure that this valve is closed (fire continues to burn – no change in fire intensity)
03:30	The CGT Maintenance Mechanic and the CGT Compressor Station Operator check the position of the A and B field dump line valves. The dump valve for the Artemas B field slug catcher was discovered to be damaged due to the fire and had failed in the open position. The line was then manually closed and the fire subsequently extinguished in very short order.
04:00	The CGT Manager – Operations gives Fire Department personnel permission to enter the site and put out office and various other small fires within the site.
08:00	Incident Management Call commences.
08:45	A CGT Senior Engineer contacts PHMSA and informs them of the incident.
14:30	Following assessment and safely securing of Artemas Compressor Station, Site Evaluation and Incident Investigation commences.

Property damage was limited to the compressor station and related facilities and did not impact public property. There were no injuries or fatalities as a result of this incident. The main office structure and several outbuildings were destroyed due to the heat and flames. As a result of the incident that occurred at the station on November 3, 2011, supply and deliverability were not impacted.

Summary of Return-to-Service

Damage Summary: As a result of the incident, heat and fire damage was prevalent throughout the Artemas facility, with the most severe damage being in the area of the Field-A filter separator and heaters. Nisource Gas Transmission and Storage (NGTS) contracted with DNV to perform a fitness for service assessment of the station equipment under API 579-1/ ASME FFS-1 2007(part 11) for the assessment of fire damage. A summary of the findings are outlined in *(Appendix C- Artemas In House Incident Report, page 8, Damage Assessment).*

Restoration of Service Plan: Shortly following the incident, NGTS developed a short and long-term return to service plan. The short term plan focused on restoring as much service as possible due to the winter heating season, and involved temporarily modifying equipment and piping layouts in order to safely operate Storage Field A and to provide gas from the field to the main transmission line. On January 1, 2012, NGTS performed a successful test flow from Storage Field A/B into the main transmission line and on January 2, 2012, the Storage Field-A/B was directed into the transmission line. Storage Field A and B are capable of free flowing into the main transmission line because of the pressure differential. The compressor station side of the operations will remain out of service until the appropriate remediation and testing has been completed. A copy of the detailed plan is attached *(Appendix C – Artemas In House Incident Report)*. A copy of the metallurgical report is also attached *(Appendix E -DNV Report "Failure Analysis of a Two-Inch Diameter Drain Line that Ruptured in Service")*

Corrective Action Bulletin: NGTS issued a company-wide Corrective Action Bulletin on February 17, 2012. The Corrective Action Bulletin was distributed to notify all company employees of a newly developed Integrity Plan covering liquid dump piping. The Bulletin also addressed lessons learned and corrective actions that will be implemented as a result of the Artemas incident. System-wide corrective actions will include the following:

1) Maximo work orders will be created and issued to immediately open all manual dump valves on liquid removal device sumps to sweep the lines and remove any stagnate liquids and solids.
2) Maximo work orders will be created and issued to immediately inspect all heat trace on liquid removal device drain lines to assure proper operation.
3) An information request will be E-mailed to the local supervisor with a request to provide data to the investigation team, so that appropriate long term measures can be implemented for each liquid removal device.
4) Based on information provided through an excel spreadsheet the following Preventative Maintenance Work Orders (PM's) will be generated.
    a) A Winter Season Task with the frequency of once per week for every vessel, where applicable, to operate all manual dump valves on liquid removal piping to remove fluids/solids collecting in these areas to assist in preventing freezes and corrosion.
    b) A Winter Season Task, will be created, where applicable, to inspect the heat tracing on liquid removal device with a frequency of once per week, to assure continued operation.

(Appendix H- NGTS Corrective Action Bulletin)

Integrity Plan to Address Liquid/Dump Piping:
NGTS has developed an Integrity Plan covering pressurized liquid/dump piping at all active compressor stations throughout their system. *(Appendix C, Attachment I)*. The plan summarizes the immediate and long-term steps that will be taken to address dump/drain valve piping throughout the NGTS system. The steps outlined in the plan include the following:

1. Develop a Corrective Acton Bulletin to be distributed to NGTS Operations and Maintenance Team Leaders throughout NGTS to inform them of the circumstances surrounding the incident and to initiate initial operations/maintenance measures to help minimize similar conditions. A Corrective Action Bulletin was prepared and sent out to all NGTS Operations and Maintenance Team leaders on February 17, 2012.
2. Due to the number of locations with potential liquid/dump piping in the NGTS system, NGTS has prioritized the locations for evaluation. A prioritized (risk ranked) listing of locations for assessment of liquid/dump piping has been developed.
3. Based upon the prioritized list, NGTS will perform integrity assessments of liquid/dump piping at each location. The assessment will include measures to determine the integrity of pressurized dump/liquid piping, to evaluate potential freeze issues and to implement practices to help prevent corrosive conditions and, in some cases, may also include measures for periodic monitoring.

Investigation Details

During the initial phase of the investigation, the lead investigator for PHMSA, working in conjunction with DNV personnel, identified and secured several pipe sections and associate valves and fitting for laboratory analysis *(see photos pg 19-30- Appendix E - Lab Analysis Report DNV).* According to eye witness statements, the initial fire originated at or near Filter Separator-A. Upon investigation, the ruptured pipe section was identified to be the initial source of the fire. Samples of the failed pipe section as well as other piping and fittings in the immediate area were collected and packaged in accordance with CGT's sample collection and chain of custody procedures. The collected specimens were then shipped to DNV's laboratory for analysis.

A review of records provided by CGT indicates there have been no incidents or Safety Related Conditions at the Artemas Station or storage fields within the past five years. Also, no leaks have been reported during this five year period.

The Artemas Storage field does have a history of internal corrosion issues dating back to the 1990's. The Artemas A Storage Field was upgraded in 2001. The upgrade included major changes to minimize telescoping of field lines, conversion to a piggable mainline to facilitate fluid removal, and replacement of short well lines. An integrity assessment and remediation program was added to this upgrade because of a line rupture in 2000 that indicated problems with internal corrosion. The Artemas B Field underwent an integrity assessment in 2001 due to the conditions in Artemas A Field that indicated internal corrosion was present.

There have been four leaks associated with internal corrosion at the Artemas A Field. These leaks span a period from 1990 through 2000 and resulted in pipe replacement. There is no history of internal corrosion leaks in the Artemas B Field on Line 10163. Since 1994, both storage Field A and B have been treated using corrosion inhibitor to control internal corrosion. Since 2000, CGT has developed and implemented a Facility Specific Internal Corrosion Control Plan for storage fields throughout their system. The facility-specific internal corrosion plan applies to the assessment, sampling, testing, evaluating, monitoring, and remediation for internal corrosion control management. (See Appendix G for plan details).

Based on a review of the plan and associated records, CGT has taken adequate steps to control internal corrosion within the Artemas system. However, modifications to the existing plan will be required to ensure that dead legs and other locations where fluids can accumulate are evaluated on a more frequent basis.

Description of Failure

Based on visual and laboratory analysis data, the rupture that occurred in the Separator drain piping initiated along the 5:00 o'clock position at a region of internal wall loss. The area of thinnest remaining wall present along the rupture was approximately 7-inches in length, spanning from the upstream girth weld to 7-inches downstream of the upstream girth weld. Longitudinal internal wall loss features were present along the length of the rupture. There was no evidence of significant external corrosion on the ruptured piping. *(Appendix E, page 29, figure 17).*

Integrity Verification and Remediation

NGTS contracted with DNV to perform a fitness for service assessment of the station equipment under API 579-1/ ASME FFS-1 2007(part 11) for the assessment of fire damage. A summary of the findings are outlined in the Artemas In House Incident report *(Appendix C, page 8, Damage Assessment).*

Metallurgical Analysis

The pipe sections related to the failure were sent to the DNV Ohio lab for analysis. The lab results are as follows:

1. The rupture initiated along the approximate 5:00 o'clock orientation in the B2 Drain Piping at a region of internal wall loss.
2. The area of thinnest remaining wall present along the rupture was approximately 7-inches in length, spanning from the upstream girth weld to 7-inches downstream of the upstream girth weld.
3. Longitudinal internal wall loss features were present along the length of the rupture.
4. There was no evidence of significant external corrosion on the ruptured piping.
5. The tensile properties of two-inch nominal diameter drain piping that was unaffected by the fire meet the minimum specifications for API 5L Grade B line pipe steel in place at the time of manufacture.
6. The chemistry of the pipe steel from the joint of piping that failed meets the composition specifications for API 5L Grade B line pipe steel in place at the time of manufacture.
7. The microstructure of the ruptured pipe contained slightly spherodized pearlite, which is consistent with carbon steel pipe exposed to a fire.
8. The estimated burst pressure using the effective area method in CorLAS™ was 6054 psig. This is significantly higher than the failure pressure of 1591 psig
9. Radiographic inspection of representative girth welds from the various piping assemblies associated with the drain piping coming off the bottom of the separator revealed only 1 out of 27 welds inspected had indications that would not meet the minimum criteria in API 1104. This was not related to the failure.
10. Radiographic inspection of the B1 and B3 Flanges adjacent to the failed pipe section revealed the presence of internal wall loss in the drain piping that failed.
11. A leak associated with internal wall loss was identified on the elbow of the B3 Flange. The leak measured 0.053-inches wide and 0.345-inches long and was located approximately at the 6:00 o'clock orientation.

The results of the analysis indicate that the rupture was likely due to water freezing in the drain line. The frozen liquid caused the piping to expand, producing ductile tearing at internal corrosion features. The resultant flaw size was critical for the material properties, dimensions, and operating pressure of the piping.

Freezing occurred sometime prior to the failure. During the freezing event, tearing occurred at the internal corrosion grooves, producing a larger flaw than that measured based on fractography. This ductile tearing would be indistinguishable from the ductile tearing from the final fracture.

Evidence to support this conclusion include: (1) the high predicted failure pressure using CorLAS™, (2) the fracture morphology, (3) below freezing temperatures recorded in the area for multiple days leading up to the failure, and (4) the fact that gas was being injected into the storage field at the time of the failure.

CorLAS™ predicted a failure pressure that was much higher than any reasonable operating pressure for the piping. The report indicates that some other force must have acted on the piping to cause the failure. The mechanism for the corrosion could not be determined from the information provided and the results of the analysis.

1. The fracture morphology, showing ductile features on the fracture surface and possible ductile features at other longitudinal grooves on the piping, is consistent with ductile tearing.
2. The below freezing temperatures reported for the area indicate that freezing was possible.
3. The fact that gas was being injected into the wells at the time of the failure indicates that the water present in the piping was likely condensed water. If gas was being withdrawn from the storage wells, brine fluid would have likely been present, which is less likely to freeze compared with condensed water.
4. The presence of the internal corrosion was a contributing factor to the failure.
5. It is possible that multiple factors played a role in the internal corrosion observed on the piping.

Findings and Contributing Factors

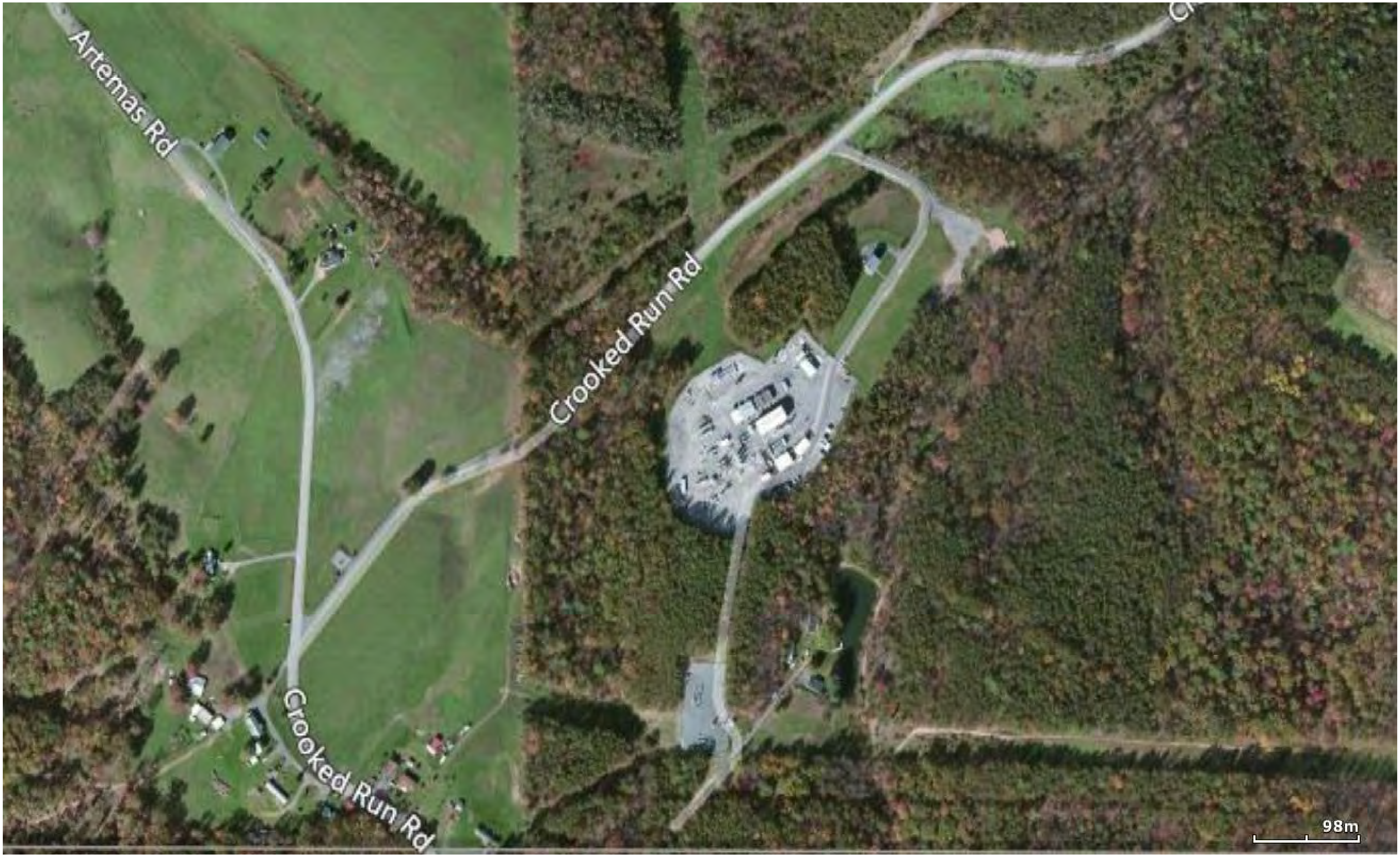
The cause of the failure was wall thinning due to internal corrosion. The internal corrosion was caused by fluid collecting and remaining stagnant in the manual dump drain for lengthy periods of time. The fluid would collect and become isolated in a 2 foot section of piping on the high pressure side between the bottom of the sump and the manual dump valve. Fluid would remain in this section of piping until the dump valve was manually operated to discharge the fluids. According to operating personnel, the manual dump valve was operated once or twice a year since the separator was also equipped with an automatic dump system. It should be noted that internal corrosion was only identified on the manual dump piping, and there were no indications of internal corrosion on the piping associated with the automatic dump system.

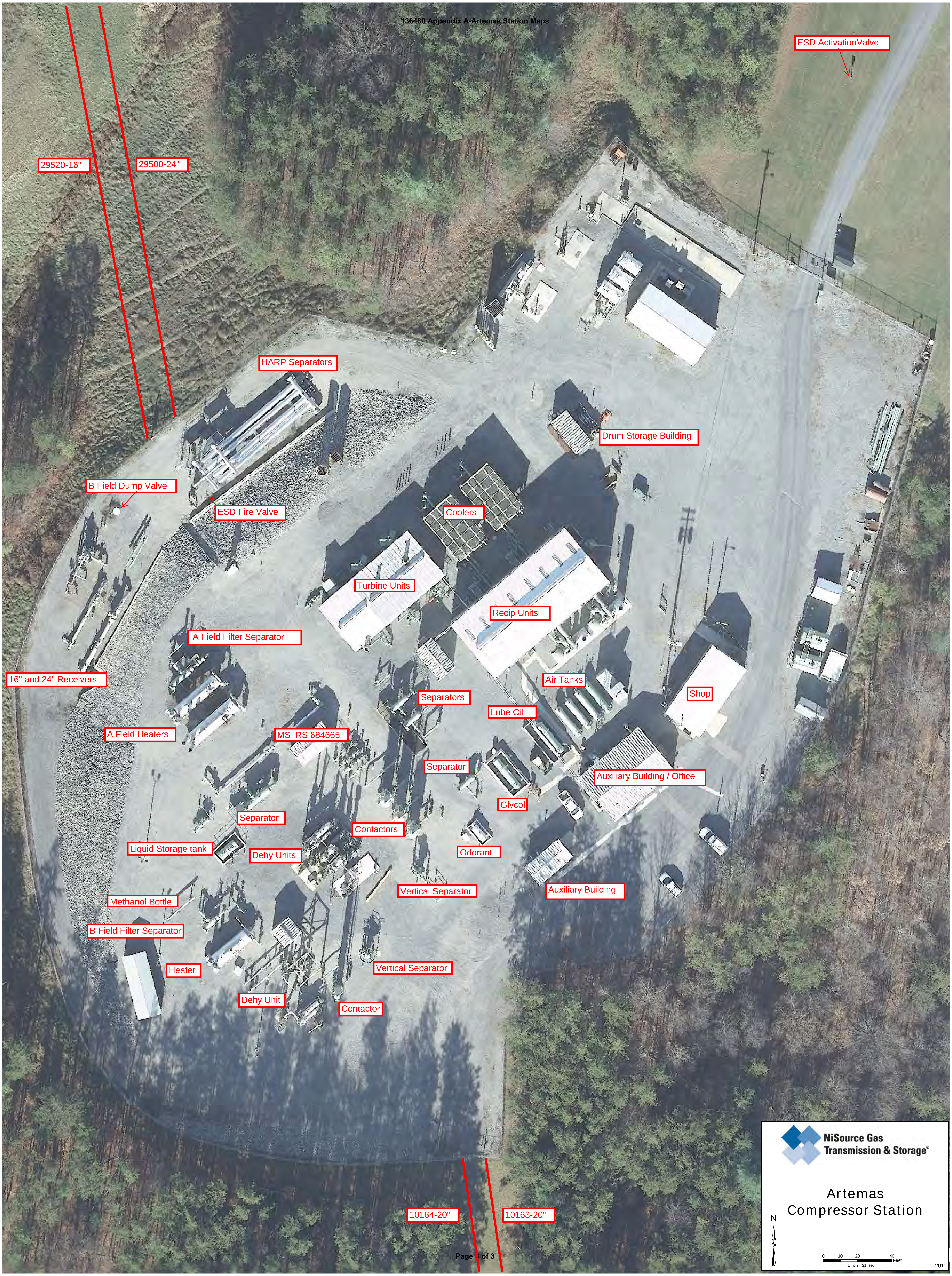
A contributing factor to the pipe rupture was thermal expansion due to frozen fluid within the pipe. DNV conducted remaining wall loss calculations to determine the failure pressure of the ruptured pipe section. Based on these calculations, DNV determined that the wall loss, due to internal corrosion, was not enough to cause the rupture of the dump line at operating pressure. Using the effective area method in the CorLas Software, DNV found that the estimated burst pressure of 6054 psig was significantly higher than the calculated failure pressure of 1591 psig. Although this piping was equipped with heat tracing and insulated to prevent freezing, it is believed that the heat tracing could have failed causing the fluid within the piping to freeze and expand thus weakening the structural integrity of the pipe. The combination of wall thinning and pipe expansion due to the frozen fluid weakened the pipe causing it to fail well below its design pressure**.** *(See Appendix E –Lab Analysis Final Report, pg 13, Summary and Conclusions)*

Appendices

Appendix	**Description**
A	Artemas Station Maps
B	NRC Report 994393
C	Artemas In-House Incident Report, 3/9/2012
D	Incident Report to PHMSA 20110389-15470
E	Lab Analysis Final Report DNV
F	Coupon-Gas-Liquid Sample Data
G	Artemas A and B Facility Specific Internal Corrosion Control Plan
H	NGTS Corrective Action Bulletin 2-16-12
I	Artemas Station Pressure Chart


A Field Separator


Artemas Rd
Crooked Run Rd
Crooked Run Rd
98m


ESD ActivationValve
29520-16"
29500-24"
HARP Separators
Drum Storage Building
B Field Dump Valve
ESD Fire Valve
Coolers
Turbine Units
Recip Units
A Field Filter Separator
16" and 24" Receivers
Air Tanks
Shop
Separators
Lube Oil
A Field Heaters
MS RS 684665
Separator
Auxiliary Building / Office
Glycol
Separator
Contactors
Liquid Storage tank
Dehy Units
Odorant
Vertical Separator
Auxiliary Building
Methanol Bottle
B Field Filter Separator
Heater
Vertical Separator
Dehy Unit
Contactor
10164-20"
10163-20"
NiSource Gas Transmission & Storage
Artemas
Compressor Station
N
0 10 20 40 Feet
1 inch = 31 feet
2011

This report is forwarded for your situational awareness. CMC 6-1863

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 # 994393

INCIDENT DESCRIPTION

*Report taken by: E4 BRANDON WEATHERLY at 02:49 on 03-NOV-11
Incident Type: FIXED
Incident Cause: EQUIPMENT FAILURE
Affected Area:
Incident was discovered on 03-NOV-11 at 00:50 local incident time.
Affected Medium: AIR ATMOSPHERE

REPORTING PARTY
Name: DAVID ADLER
Organization: COLUMBIA GAS TRANSMISSION CORP.
Address: 1700 MACCORKLE AVE SOUTHEAST
CHARLESTON, WV
COLUMBIA GAS TRANSMISSION CORP. reported for the responsible party.
PRIMARY Phone: (304)5463713
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY
Name: DAVID ADLER
Organization: COLUMBIA GAS TRANSMISSION CORP.
Address: 1700 MACCORKLE AVE SOUTHEAST
CHARLESTON, WV
PRIMARY Phone: (304)5463713

INCIDENT LOCATION
210 HARRISBURG PIKE County: BEDFORD
City: ARTEMAS State: PA

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

DESCRIPTION OF INCIDENT

CALLER IS REPORTING A RELEASE OF AN UNKNOWN AMOUNT OF NATURAL GAS INTO THE ATMOSPHERE. CALLER STATED THAT A LINE FAILURE WAS BELIEVED TO BE THE CAUSE OF THE RELEASE.

SENSITIVE INFORMATION

INCIDENT DETAILS

Package: NO
Building ID:
Type of Fixed Object: OTHER
Power Generating Facility: NO
Generating Capacity:
Type of Fuel:
NPDES:
NPDES Compliance: UNKNOWN

IMPACT

Fire Involved: NO   Fire Extinguished: UNKNOWN

INJURIES: NO   Hospitalized: Empl/Crew: Passenger:
FATALITIES: NO   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:	N		Major Artery:N	
Waterway:	N			
Track:	N			

Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

SHUTDOWN SYSTEM, SECURED OPERATIONS, CLEAN UP CREW ON-SITE.
Release Secured: UNKNOWN
Release Rate:
Estimated Release Duration:

WEATHER

Weather: PARTLY CLOUDY, 39ºF

ADDITIONAL AGENCIES NOTIFIED

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

NOTIFICATIONS BY NRC

ATLANTIC STRIKE TEAM (MAIN OFFICE)
03-NOV-11 03:00 (609)7240008
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
03-NOV-11 03:00 (202)3661863
U.S. EPA III (MAIN OFFICE)
(215)8149016
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
03-NOV-11 03:00 (202)2829201
NJ STATE POLICE (MARINE SERVICES BUREAU)
03-NOV-11 03:00 (609)9636900
NOAA RPTS FOR PA (MAIN OFFICE)
03-NOV-11 03:00 (206)5264911
PA STATE POLICE (BUREAU OF CRIMINAL INVESTIGATION)
03-NOV-11 03:00 (717)5255260
MD DEPT OF ENV (MAIN OFFICE)
03-NOV-11 03:00 (866)6334686
PA EMERG MGMT AGCY (MAIN OFFICE)
03-NOV-11 03:00 (717)6512001

ADDITIONAL INFORMATION

CALLER HAD LIMITED INFORMATION ON THE INCIDENT AT THIS TIME.

*** END INCIDENT REPORT #994393 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil

Appendix C Artemas In-House Incident Report, 3/9/2012

This document is on file at PHMSA

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0522 EXPIRATION DATE: 01/31/2014

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Report Date:**	12/02/2011
	No.	20110389 - 15470 (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	

Last Revision Date:	03/15/2012
1. Operator's OPS-issued Operator Identification Number (OPID):	2616
2. Name of Operator	COLUMBIA GAS TRANSMISSION CORP
3. Address of Operator:	
3a. Street Address	1700 MACCORKLE AVE., SE
3b. City	CHARLESTON
3c. State	West Virginia
3d. Zip Code:	25314
4. Local time *(24-hr clock)* and date of the Incident:	11/03/2011 00:45
5. Location of Incident:	
Latitude:	39.72573
Longitude:	-78.4217
6. National Response Center Report Number (if applicable):	994393
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	11/03/2011 02:45
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):	15,000.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	
12. Estimated volume of accompanying liquid release (Barrels):	
13. Were there fatalities?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total fatalities (sum of above)	
14. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
14a. Operator employees	
14b. Contractor employees working for the Operator	
14c. Non-Operator emergency responders	
14d. Workers working on the right-of-way, but NOT associated with this Operator	
14e. General public	
14f. Total injuries (sum of above)	
15. Was the pipeline/facility shut down due to the incident?	Yes

- If No, Explain:	
- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	11/03/2011 05:00
15b. Local time pipeline/facility restarted	
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	Yes
17. Did the gas explode?	No
18. Number of general public evacuated:	
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	11/03/2011 00:45
19b. Local time operator resources arrived on site	11/03/2011 00:45

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:	Pennsylvania
3. Zip Code:	17211
4. City	Artemas
5. County or Parish	Bedford
6. Operator designated location	
Specify:	
7. Pipeline/Facility name:	Artemas Compressor Station
8. Segment name/ID:	
9. Was Incident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Incident :	Operator-controlled property
11. Area of Incident (as found) :	Aboveground
Specify:	Typical aboveground facility piping or appurtenance
Other – Describe:	
Depth-of-Cover (in):	
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 Compressor Station Equipment and Piping
3. Item involved in Incident:	Pipe
- If Pipe – Specify:	Pipe Body
3a. Nominal diameter of pipe (in):	2
3b. Wall thickness (in):	.218
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	35,000

3d. Pipe specification:	API 5L
3e. Pipe Seam – Specify:	Seamless
- If Other, Describe:	
3f. Pipe manufacturer:	
3g. Year of manufacture:	
3h. Pipeline coating type at point of Incident – Specify:	None
- 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:	2003
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:	Circumferential
- If Other – Describe:	
Approx. size: in. (widest opening):	2
by in. (length circumferentially or axially):	4
- 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:	75
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?	No
6. Were any of the fatalities or injuries reported for persons located outside the PIR?	No
7. Estimated Property Damage :	
7a. Estimated cost of public and non-Operator private property damage	$ 5,000
7b. Estimated cost of Operator's property damage & repairs	$ 500,000
7c. Estimated cost of Operator's emergency response	$ 1,000
7d. Estimated other costs	$ 0
Describe:	Note that numbers will be updated in the supplemental report.
7e. Total estimated property damage (sum of above)	$ 506,000
<u>Cost of Gas Released</u>	
7f. Estimated cost of gas released unintentionally	$ 53,400
7g. Estimated cost of gas released during intentional and controlled blowdown	$ 0
7h. Total estimated cost of gas released (sum of 7.f & 7.g above)	$ 53,400

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	1,942.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	2,400.00
3. Describe the pressure on the system or facility relating to the Incident:	Pressure did not exceed MAOP

4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Incident operating under an established pressure restriction with pressure limits below those normally allowed by the MAOP?	No
- If Yes - (*Complete 4a and 4b below)*	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	No
- If Yes - (*Complete 5a. - 5f. below):*	
5a. Type of upstream valve used to initially isolate release source:	
5b. Type of downstream valve used to initially isolate release source:	
5c. Length of segment isolated between valves (ft):	
5d. Is the pipeline configured to accommodate internal inspection tools?	
- 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?	
- 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:	
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Incident?	Yes
- If Yes:	
6a. Was it operating at the time of the Incident?	Yes
6b. Was it fully functional at the time of the Incident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	No
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
7. How was the Incident initially identified for the Operator?	Notification From Public
- 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 unintended gas release appears to have initiated at the two inch liquid dump piping at the bottom of the sump tank below the filter separator. This area was not equipped with an RTU, so it could not be seen by the controller.
- 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:	1
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:	G1 - Corrosion Failure

G1 - Corrosion Failure - *only one* ***sub-cause*** *can be picked from shaded left-hand column*

Corrosion Failure – Sub-cause:	Internal Corrosion
- 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:	General Corrosion
- If Other, Describe:	
7. Cause of corrosion *(select all that apply)*:	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other	Yes
- If Other, Describe:	The metallurgical analysis coiuld not determine the exact corrosion mechanism at the 2-inch pipe.
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	Yes
- Other	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*:	
- Low point in pipe	Yes
- Elbow	
- Drop-out	
- Other	
- If Other, Describe:	
10. Was the gas/fluid treated with corrosion inhibitors or biocides?	Yes
11. Was the interior coated or lined with protective coating?	No
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	Yes
13. Were corrosion coupons routinely utilized?	Yes
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?	No
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?	No
- If Yes,	
Most recent year tested:	
Test pressure (psig):	
16. Has one or more Direct Assessment been conducted on this segment?	No
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	

- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
17. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	No
17a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year examined:	
- Guided Wave Ultrasonic	
Most recent year examined:	
- Handheld Ultrasonic Tool	
Most recent year examined:	
- Wet Magnetic Particle Test	
Most recent year examined:	
- Dry Magnetic Particle Test	
Most recent year examined:	
- Other	
Most recent year examined:	
If Other, Describe:	

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

Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Incident generated in conjunction with an extreme weather event?	
6a. If yes, specify: *(select all that apply)*:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	

G3 - Excavation Damage *only one **sub-cause** can be picked from shaded left-hand column*

Excavation Damage – Sub-Cause:	
- If Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage Due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in Incident" (From Part C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Incident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Year:	
- Ultrasonic	
Year:	
- Geometry	

Year:	
- Caliper	
Year:	
- Crack	
Year:	
- Hard Spot	
Year:	
- Combination Tool	
Year:	
- Transverse Field/Triaxial	
Year:	
- Other:	
Year:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
5a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Year:	
- Guided Wave Ultrasonic	
Year:	
- Handheld Ultrasonic Tool	
Year:	
- Wet Magnetic Particle Test	
Year:	
- Dry Magnetic Particle Test	
Year:	
- Other	
Year:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from *(select all that apply)*:	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred *(select all that apply)*:	
- Public	
- If Public, Specify:	
- Private	
- If Private, Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator :	
10. Type of excavation equipment :	

11. Type of work performed :	
12. Was the One-Call Center notified? - Yes - No	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption: (hours)	
17. Description of the **CGA-DIRT Root Cause** (*select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, then one predominant second level CGA-DIRT Root Cause as well*):	
- Predominant first level CGA-DIRT Root Cause:	
- If One-Call Notification Practices Not Sufficient, Specify:	
- If Locating Practices Not Sufficient, Specify:	
- If Excavation Practices Not Sufficient, Specify:	
- If Other/None of the Above, Explain:	

G4 - Other Outside Force Damage - only one **sub-cause** can be selected from the shaded left-hand column

Other Outside Force Damage – Sub-Cause:	
- If Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation:	
- If Electrical Arcing from Other Equipment or Facility:	
- If Previous Mechanical Damage NOT Related to Excavation:	
Complete Questions 3-7 ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Incident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other:	
Most recent year run:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted	

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

If

- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	

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

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

Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional Factors (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Incident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Incident since January 1,2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	

Describe:	
G6 - Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify:	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- Pressure Regulator	
- ESD System Failure	
- Other	
- If Other, Describe:	
- If Compressor or Compressor-related Equipment:	
2. Specify:	
- If Other, Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other, Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other, Describe:	
- If Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Compressor), Vessel Plate, or other Material:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported gas/fluid	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 – Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
- If Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage:	
- If Underground Gas Storage, Pressure Vessel, or Cavern Allowed or Caused to Overpressure:	
1. Specify:	

- If Other, Describe:	
- If Valve Left or Placed in Wrong Position, but NOT Resulting in an Overpressure:	
- If Pipeline or Equipment Overpressured:	
- If Equipment Not Installed Properly:	
- If Wrong Equipment Specified or Installed:	
- If Other Incorrect Operation:	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Incident related to: *(select all that apply)*	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Incident:	
5. Was the task(s) that led to the Incident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Incident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Incident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART - H NARRATIVE DESCRIPTION OF THE INCIDENT

At approximately 12:30 am on Thursday, November 3, 2011, a neighbor of the Artemas Compressor station called the local Columbia Gas Transmission Maintenance Mechanic to report an incident and fire at the station. That employee contacted a second company employee for assistance at the station. The NGT&S Monitoring Center was also contacted to inform them of the possible incident.

Upon confirming the fire and initiating an ESD of the station, the area was secured. Company personnel worked with the local fire department to ensure the safety of the public and the area. It was found that the dump valve for the Artemas B field slug catcher had failed in the open position. Upon closing this valve, the fire was fully extinguished.

The results of the analysis by a third party expert in metallurgy and failure analysis indicated that the rupture was likely due to water freezing in the drain line. The frozen liquid caused the piping to expand, producing ductile tearing at internal corrosion features. The resultant flaw size was critical for the material properties, dimensions, and operating pressure of the piping.

Freezing occurred sometime prior to the failure. The presence of the internal corrosion was a contributing factor to the failure.

The company has developed an Integrity Plan covering pressurized liquid/dump piping from vessels at its active compressor stations. The plan summarizes immediate initial steps as well as long term steps that will be taken to address dump/drain valve piping company-wide.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	David E. Adler
Preparer's Title	System Integrity Engineer
Preparer's Telephone Number	304-357-2378

Preparer's E-mail Address	dadler@nisource.com
Preparer's Facsimile Number	304-357-3804
Authorized Signature's Name	Perry M. Hoffman
Authorized Signature Title	Manager System Integrity
Authorized Signature Telephone Number	304-357-2548
Authorized Signature Email	mikehoffman@nisource.com
Date	03/15/2012

Appendix E Lab Analysis Final Report DNV

This document is on file at PHMSA

Appendix F Coupon-Gas-Liquid Sample Data

This document is on file at PHMSA

Appendix G

Artemas A and B Facility Specific Internal Corrosion Control Plan

This document is on file at PHMSA

Appendix H

NGTS Corrective Action Bulletin 2-16-12

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