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

Principal Investigator	Gene Roberson
Region Director	R. M. Seeley
Date of Report	3/1/2013
Subject	Failure Investigation Report – Gulf South Pipeline Carthage Junction Compressor Station

Operator, Location, & Consequences

Date of Failure	02/14/2011
Commodity Released	Natural Gas
City/County & State	Carthage, Texas Panola County
OPID & Operator Name	31728 Gulf South Pipeline Company, LP
Unit # & Unit Name	864 Carthage
SMART Activity #	133508
Milepost / Location	Carthage Junction Compressor Station
Type of Failure	Check valve failure during unit shutdown resulting in station fire.
Fatalities	None
Injuries	None
Description of area impacted	Rural station site.
Property Damage	$30,065,800

Executive Summary

At approximately 10:22 p.m. Central standard time (CST), on February 14, 2011, an explosion and fire occurred at the Gulf South Pipeline Company, LP (Gulf South) Carthage Junction Compressor Station in Panola County, Texas. The PHMSA Southwest Region conducted an onsite investigation of the incident. At the time of the incident, Gulf South was in the process of shutting down their T-7 compressor unit. The investigation identified a failed check valve on the compressor discharge, which prevented the unit discharge valve from closing during the shutdown. The failure of the valve and the ineffectiveness of the Emergency Shutdown system (ESD) contributed to the incident. The Gulf South system is monitored and controlled by gas control in Owensboro, Kentucky. Local emergency personnel responded to the scene. There were no injuries, road closures, or resident evacuations associated with this incident. The station ESD was finally activated and the resulting fire burned itself out by February 15, 2011, 2:30 a.m. CST.

Figure 1-Carthage Junction Compressor Building

System Details

Gulf South Pipeline Company, LP is a subsidiary of Boardwalk Pipeline Partners. Gulf South's primary function is the transportation of natural gas for industrial and commercial deliveries in Texas and Louisiana. They also deliver natural gas to several other large transmission systems for further delivery to the East Coast.

Carthage Junction is located on the original Gulf South system that moves natural gas from southeast Texas to northwest Louisiana. Several lateral systems deliver gas to the Carthage Junction. In 2006, Gulf South began construction of a new 30-inch pipeline system to deliver shale gas from north Texas into Carthage Junction, and Gulf South subsequently constructed a 42-inch pipeline across northern Louisiana under a PHMSA approved 80 percent special permit (PHMSA 2006-26533). The pipeline was constructed to transport gas from Texas into Louisiana. This new construction project included the installation of 3 additional turbine compressors primarily for the 42-inch pipeline at Carthage Junction. The special permit did not include the station piping, and all compressor and station piping was designed at the required 50 percent design factor.

The station is remotely operated and is only manned during the day shift. The two compressor systems (Units 1,2,3 and Units 5,6,7) were designed to operate independently from each other even though they were located at the same site. Later, a cross-over meter station was installed to allow the transfer of gas between the two systems (Appendix A).

The failure occurred within the station and involved station piping only. A reduction in the volume of delivered gas was the only effect on the system. No previous failures were noted in the 42-inch system.

Pipe Specifications

The pipe involved in the failure, specifically the 24-inch suction elbow, was part of the station pipeline. No line pipe failed during this event. Internal components of an inline check valve downstream of Unit T-7 were found to have failed during unit shutdown causing a chain reaction of other failures. The maximum allowable operating pressure (MAOP) of the pipeline and station is 1330 psig.

Events Leading Up to the Failure

The Carthage Junction Station was operating at 1137 psig (MAOP 1330 psig) on Monday, February 14, 2011. All three units (T-5, T-6, and T-7) were online when gas control determined that, due to delivery volumes, they would shut down T-7. At 10:22 p.m. CST, a remote shutdown signal was issued by the controller. The PLC (programmable logic controller/digital computer) handled all of the sequences of the shutdown once the command was given. Approximately 2 minutes later, multiple alarms were received from the station indicating fire signals and ESD activation. A station employee was called out to respond to the site to confirm and update the controller regarding the activation of the alarms from the supervisory control and data acquisition (SCADA) system.

The ESD activation should have isolated the compressor station from the pipeline through a bypass mode and blown down all the gas in the station piping through a vent system. However, after the pipeline modifications were completed in 2007, the configuration of the ESD at the station did not allow the isolation to occur, which allowed the escaping gas to feed the fire at the station for an additional 20 minutes until a manual bypass valve could be closed by the responding station employee (Appendix A).

Gulf South reported the release to the National Response Center (NRC) at approximately 11:24 p.m. CST on February 14, 2011 (See Appendix B).

Emergency Response

Gulf South's Carthage Junction Station gave off an alarm and the ESD automatically activated while the T-7 turbine compressor was going through a shutdown sequence. This was observed by Gulf South's Control Center in Owensboro, Kentucky, and the local station operator was called to respond to the incident. When the operator arrived on the scene, the station was on fire due to natural gas escaping from a failed elbow and the ignition of lube oil. Although the ESD had functioned correctly for part of the station, the crossover meter station continued to feed the fire until it could be manually shut in. It was later determined that the new crossover meter station was not connected to the ESD, which is what caused this error. The ESD system did not isolate the system due to this improper design of the bi-directional meter installation. Gas fed the fire for an additional 20 minutes until a manual bypass valve could be closed, which added to the station damage. The station isolation was confirmed, and the fire was allowed to burn out.
(which did not allow the ESD to isolate the supply of natural gas to the fire.
Local emergency and fire personnel responded to the scene as well. Due to the remoteness of the station, no roads were closed, and no residents were evacuated.

Summary of Return-to-Service

Following the emergency response, Gulf South locked out the T-5, T-6, and T-7 compressors pending a further investigation. The pipeline was not affected and remained in service.

A plan that included a complete evaluation of all piping and equipment affected by the fire was developed for the investigation of the incident . Unit T-5 was repaired and returned to service in approximately 30 days. Unit T-6 was out of service for 58 days, and a replacement unit was installed in the place of T-7 and was returned to service on July 12, 2011. The building was completely rebuilt. The ESD system was modified to include an automatic isolation valve within the cross-over meter station that could be activated by either of the 2 station ESD's.

Gulf South replaced 8 24-inch ENTECH check valves within their East Texas to Mississippi project. The failed check valve and elbow fitting were sent to Stress Engineering for evaluation and testing.

Investigation Details

At approximately 11:24 p.m. CST, February 14, 2011, Gulf South reported to the NRC a release of natural gas and fire at their Carthage Junction Station in Panola County, Texas. The station was completed in 2007 to deliver gas to a new 80 percent waiver pipeline constructed across north Louisiana. PHMSA's Southwest Region received the incident notification and made plans to have an investigator on site. The investigator arrived on site at 8:00 a.m. on February 16, 2011. Since the building had collapsed onto the turbine units due to the fire, the site was deemed unsafe for a close unit evaluation. Due to the logistics of removing the collapsed building, it was several weeks before a thorough evaluation of the failed elbow could be performed. Additional details involving the failed check valve were also identified during this time. Once cleared, the site was entered and the extent of damage was assessed. The operator's written report can be seen in Appendix D.

Requests were made for site drawings, material documentation, SCADA records, and hydrostatic test records.

The site drawings established the station configuration and how the systems operate within the boundaries of the station. Material documentation of the failed fitting and pipe confirmed the piping and components met required manufacturer standards. MAOP documentation and calculations were verified by PHMSA. This data, with the addition of the hydrostatic test records, confirmed the operators established MAOP for the station. SCADA records provided a timeline of system conditions and actions taken at the time of incident and confirmed that the MAOP was not exceeded prior to or during the accident. The MAOP of the pipeline and station is 1330 psig, and the incident occurred at 1137 psig.

The addition of the new units within the station determined that two ESD systems would be incorporated due to the independent operations of the two stations on one site. No issues were identified with the original systems. A bi-directional meter station was then constructed to allow gas to be exchanged between the two systems. Considerations to the effects of this station on the ESD systems were not documented. When the ESD activated, gas continued to flow between the two systems for an additional 20 minutes until the manual bypass valve could be closed.

From the investigation, it appears that the sequence of events leading to this failure was as follows:

- During a routine shut down of the T-7 unit, the discharge valve was lodged partially open due to the failure of the internal parts of a Cameron ENTECH check valve;
- The compressor went into a reverse rotation, causing a pump seal failure;
- A lube oil fire ignited from the escaping product from the failed seals; and
- The 24-inch suction elbow failed.

The station fire caused the metal building structure to collapse due to the intense heat. No personal injuries were associated with incident due to its occurrence during unmanned hours, and all damage was within the station limits. The PHMSA investigator was able to view the site with the operator. No cause for failure was apparent from a visual examination.

Mechanical Analysis

The Cameron ENTECH™ 24-inch nozzle check valve that was involved in the incident was sent to Stress Engineering in Houston, Texas, for metallurgical lab analysis.

Figure 2 - Check Valve Center with sheared bolt

The lab concluded that the central assembly bolt in the check valve failed, releasing the internal parts, which then traveled downstream into the compressor station discharge valve. As a result of their findings, Cameron issued an "ENTECH Product Notification Letter" to inform its customers of the possible issues associated with the 24-inch EMTECH nozzle check valve due to possible over-torqueing of the central tie bolts during assembly in 2007 and 2008. Cameron later issued a second "ENTECH Product Notification Letter" to offer replacement valves for the valves manufactured in their Hammond, Louisiana, plant during 2007 and 2008. Gulf South replaced all eight similar check valves installed in their East Texas to Mississippi expansion project.


Figure 3 – Check Valve Plug


Figure 4 – Damaged Parts

Metallurgical Analysis

The elbow was also sent to Stress Engineering in Houston, Texas, for metallurgical analysis.

Stress Engineering concluded that:

- The failure consisted of an approximately 14-inch-long longitudinal rupture at the 9-10 o'clock position of the elbow adjacent to the girth weld.
- Small oxide inclusions were present in the area of the failure and were deemed not enough to cause the failure, but they did contribute to the failure.
- Heat impingement in the area of inclusions caused the failure.
- Maximum line pressure at failure was 85 percent of MAOP.
- No measurable external and/or internal corrosion was observed on the pipe segment.
- The chemical composition and mechanical properties of the pipe base metal near the origin, but outside of the failed area, met typical requirements for line pipe steels of the era.

Conclusions

The incident was determined to be caused by a check valve failure during unit shutdown with other contributing factors. The other contributing factors included:

- The discharge valve was lodged partially open by parts of the failed check valve;
- The compressor went into a reverse rotation, causing pump seal failure;
- A lube oil fire ignited from product escaping from the failed seals;
- Heat impingement from the lube oil fire caused the 24-inchsuction elbow to fail; and

- The ESD system malfunctioned due to the improper design of the bi-directional meter installation. This allowed gas to feed the fire for an additional 20 minutes until a manual bypass valve could be closed.

A root cause analysis of the failure points to the failed check valve as the primary cause.

Appendices

A Carthage Junction Sketch

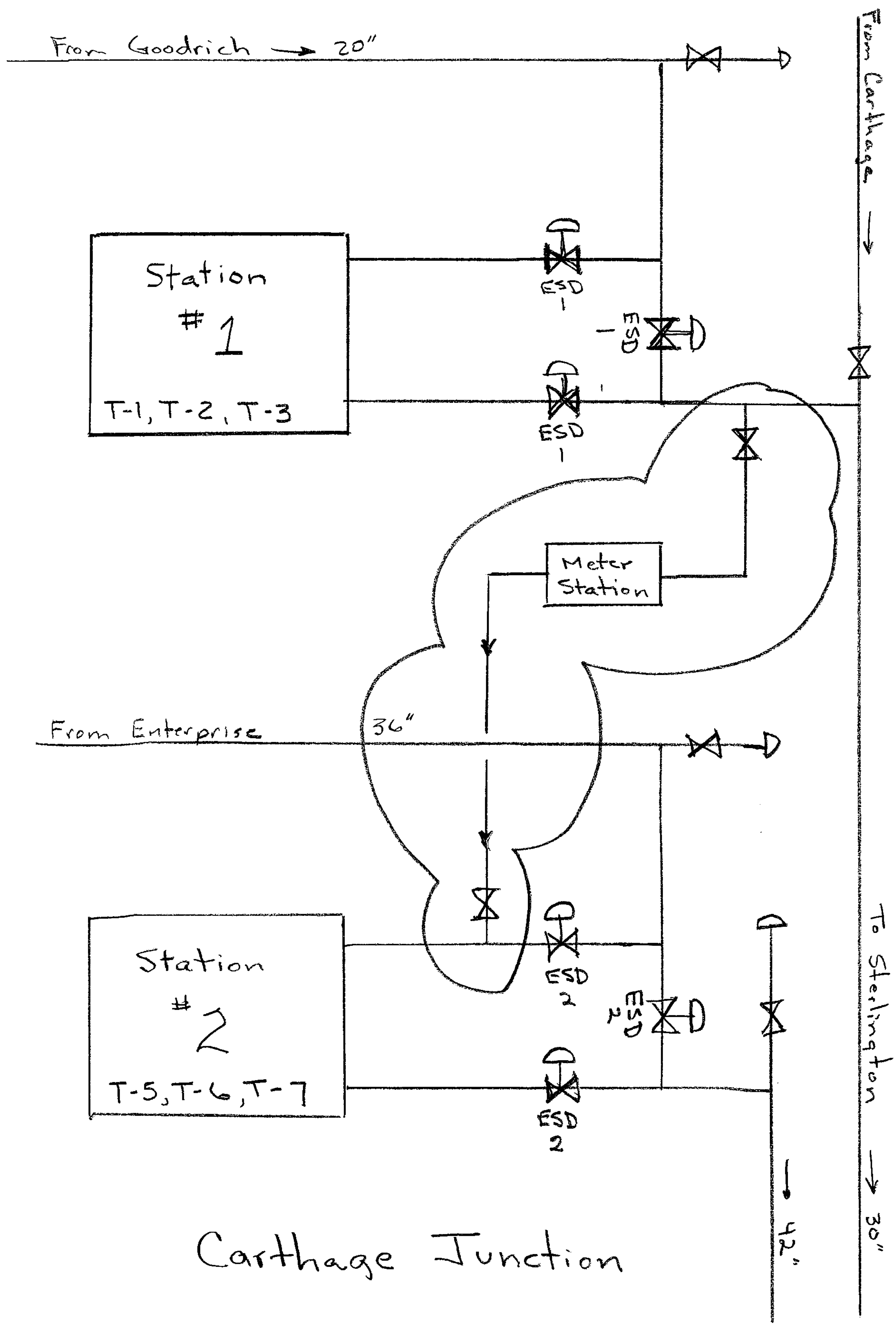
B Telephonic Notice Report – NRC # 967474

C Operator Accident Report – ODES # 20110029

D Operator Failure Investigation Report

Appendix A

Carthage Junction Sketch



Carthage Junction

Appendix B

NRC Report

[Return to Search]

NRC Number: **967474**
Call Date: **02/14/2011** **Call Time:** **23:24:07**

Caller Information

First Name:	GLEN	Last Name:	MAY
Company Name:	GULF SOUTH		
Address:	3800 FREDER		
City:	OWENSBORO	State:	KY
Country:	USA	Zip:	42301
Phone 1:	2706884730	Phone 2:	
Organization Type:	PRIVATE ENTI	Is caller the spiller?	(•) Yes ( ) No ( ) No Response
Confidential:	( ) Yes (•) No ( ) No Response		

Discharger Information

First Name:	GLEN	Last Name:	MAY
Company Name:	GULF SOUTH		
Address:	3800 FREDER		
City:	OWENSBORO	State:	KY
Country:	USA	Zip:	42301
Phone 1:	2706884730	Phone 2:	
Organization Type:	PRIVATE ENTI		

Spill Information

State:	TX	County:	PANOLA
Nearest City:	CARTHAGE	Zip Code:	75633

Location

1512 COUNTY RD

Spill Date: 02/14/2011 (mm/dd/yyyy)

Spill Time: 21:40:00 (24hh:mm:ss)

DTG Type: OCCURRED

Incident Type: FIXED FACILITY

Reported Incident Type: FIXED FACILITY

Description

CALLER REPORTED A FIRE AT

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
NATURAL GAS	ONG	0 UNKNOWN AMOUNT	

Medium Type: AIR

Additional Medium Information:

ATMOSPHERE

Injuries:

Fatalites:

Evacuations: Yes No (selected) Unknown

No. of Evacuations:

Damages: Yes No (selected) Unknown

Damage Amount:

Federal Agency Notified: Yes No Unknown (selected)

State Agency Notified: Yes No Unknown (selected)

Other Agency Notified: Yes No Unknown (selected)

Remedial Actions

FIRE DEPT. ENROUTE. GAS SH

Additional Info

NONE.

Latitude

Degrees:	32	Minutes:	49	Seconds:	0	Quadrant:	N

Longitude

Degrees:	94	Minutes:	9	Seconds:	0	Quadrant:	W

Distance from City:			Direction:	
Section:			Township:	
Range:			Milepost:	

☐ **Rescinded** **Comments** (max 250 characters)

<< Previous 1..1 of 1 << Save >>

Appendix C

Accident Report

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0522 EXPIRATION DATE: 01/31/2013

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Report Date:**	03/14/2011
	No.	20110029 - 15327 (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:	08/30/2011
1. Operator's OPS-issued Operator Identification Number (OPID):	31728
2. Name of Operator	GULF SOUTH PIPELINE COMPANY, LP
3. Address of Operator:	
3a. Street Address	9 GREENWAY PLAZA, SUITE 2800
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code:	77046
4. Local time *(24-hr clock)* and date of the Incident:	02/14/2011 21:40
5. Location of Incident:	
Latitude:	32.8616
Longitude:	-94.1599
6. National Response Center Report Number (if applicable):	967474
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	02/14/2011 22:19
8. Incident resulted from:	Reasons other than 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):	14,400.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	600.00
12. Estimated volume of accompanying liquid release (Barrels):	
13. Were there fatalities?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total fatalities (sum of above)	
14. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
14a. Operator employees	
14b. Contractor employees working for the Operator	
14c. Non-Operator emergency responders	
14d. Workers working on the right-of-way, but NOT associated with this Operator	
14e. General public	
14f. Total injuries (sum of above)	
15. Was the pipeline/facility shut down due to the incident?	Yes
- If No, Explain:	

- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	02/14/2011 21:40
15b. Local time pipeline/facility restarted	07/16/2011 00:00
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	Yes
17. Did the gas explode?	No
18. Number of general public evacuated:	0
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	02/14/2011 22:14
19b. Local time operator resources arrived on site	02/14/2011 22:15

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:	Texas
3. Zip Code:	75633
4. City	CARTHAGE
5. County or Parish	PANOLA
6. Operator designated location	Milepost/Valve Station
Specify:	00.00
7. Pipeline/Facility name:	CARTHAGE JUNCTION COPRESSOR STATION
8. Segment name/ID:	INDEX 816
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:	Inside a building
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:	Other
- If Pipe – Specify:	
3a. Nominal diameter of pipe (in):	
3b. Wall thickness (in):	
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	
3d. Pipe specification:	
3e. Pipe Seam – Specify:	

- If Other, Describe:	
3f. Pipe manufacturer:	
3g. Year of manufacture:	
3h. Pipeline coating type at point of Incident – Specify:	
- If Other, Describe:	
- If Weld, including heat-affected zone – Specify:	
- If Other, Describe:	
- If Valve – Specify:	
- If Mainline – Specify:	
- If Other, Describe:	
3i. Mainline valve manufacturer:	
3j. Year of manufacture:	
- If Other, Describe:	UNDER INVESTIGATION
4. Year item involved in Incident was installed:	2007
5. Material involved in Incident:	Material Other than Carbon Steel or Plastic
- If Material other than Steel or Plastic – Specify:	UNDER INVESTIGATION
6. Type of Incident involved:	Other
- 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:	
- If Other – Describe:	
Approx. size: in. (widest opening):	
by in. (length circumferentially or axially):	
- If Other – Describe:	
	UNKNOWN AT CURRENT TIME.

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:	1,058
4. Were any structures outside the PIR impacted or otherwise damaged due to heat/fire resulting from the Incident?	No
5. Were any structures outside the PIR impacted or otherwise damaged NOT by heat/fire resulting from the Incident?	No
6. Were any of the fatalities or injuries reported for persons located outside the PIR?	No
7. Estimated cost to Operator :	
7a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$ 0
7b. Estimated cost of gas released unintentionally	$ 62,208
7c. Estimated cost of gas released during intentional and controlled blowdown	$ 2,592
7d. Estimated cost of Operator's property damage & repairs	$ 30,000,000
7e. Estimated cost of Operator's emergency response	$ 1,000
7f. Estimated other costs	$ 0
Describe:	ONGOING
7g. Estimated total costs (sum of above)	$ 30,065,800

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	1,137.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	1,333.00
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?	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)*	INITIAL INVESTIGATION LEADS TO A COMPONENT FAILURE. NO ACTION OF GAS CONTROIL COULD LEAD TO CAUSE.
- If Yes, Describe investigation result(s) *(select all that apply)*:	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the operator), and other factors associated with fatigue	
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue	
- Provide an explanation for why not:	
- Investigation identified no control room issues	
- Investigation identified no controller issues	
- Investigation identified incorrect controller action or controller error	

- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above –	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

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

PART G - APPARENT CAUSE

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

Apparent Cause:	G8 - Other Incident Cause

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

Corrosion Failure – Sub-cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other	
- If Other – Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other	
- If Other – Describe:	
4. Was the failed item buried under the ground?	
- If Yes:	
4a. Was failed item considered to be under cathodic protection at the time of the incident?	
- If Yes, Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the incident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the incident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	

- If Internal Corrosion:	
6. Results of visual examination:	
- If Other, Describe:	
7. Cause of corrosion *(select all that apply)*:	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*:	
- Field examination	
- Determined by metallurgical analysis	
- Other	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*:	
- Low point in pipe	
- Elbow	
- Drop-out	
- Other	
- If Other, Describe:	
10. Was the gas/fluid treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
14. Has one or more internal inspection tool collected data at the point of the Incident?	
14a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage Tool	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
If Other, Describe:	
15. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes,	
Most recent year tested:	
Test pressure (psig):	
16. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
17. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
17a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year examined:	
- Guided Wave Ultrasonic	
Most recent year examined:	

- Handheld Ultrasonic Tool	
Most recent year examined:	
- Wet Magnetic Particle Test	
Most recent year examined:	
- Dry Magnetic Particle Test	
Most recent year examined:	
- Other	
Most recent year examined:	
If Other, Describe:	
G2 - Natural Force Damage - *only one **sub-cause** can be picked from shaded left-handed column*	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Incident generated in conjunction with an extreme weather event?	
6a. If yes, specify: *(select all that apply)*:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage *only one **sub-cause** can be picked from shaded left-hand column*	
Excavation Damage – Sub-Cause:	
- If Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage Due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in Incident" (From Part C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Incident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Year:	
- Ultrasonic	
Year:	
- Geometry	
Year:	
- Caliper	
Year:	
- Crack	
Year:	
- Hard Spot	
Year:	
- Combination Tool	
Year:	
- Transverse Field/Triaxial	
Year:	

- Other:	
Year:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
5a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Year:	
- Guided Wave Ultrasonic	
Year:	
- Handheld Ultrasonic Tool	
Year:	
- Wet Magnetic Particle Test	
Year:	
- Dry Magnetic Particle Test	
Year:	
- Other	
Year:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from *(select all that apply)*:	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred *(select all that apply)*:	
- Public	
- If Public, Specify:	
- Private	
- If Private, Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator :	
10. Type of excavation equipment :	
11. Type of work performed :	
12. Was the One-Call Center notified? - Yes - No	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption: (hours)	
17. Description of the **CGA-DIRT Root Cause** (*select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, then one predominant second level CGA-DIRT Root Cause as well*):	

- Predominant first level CGA-DIRT Root Cause:	
- If One-Call Notification Practices Not Sufficient, Specify:	
- If Locating Practices Not Sufficient, Specify:	
- If Excavation Practices Not Sufficient, Specify:	
- If Other/None of the Above, Explain:	
G4 - Other Outside Force Damage - only one **sub-cause** can be selected from the shaded left-hand column	
Other Outside Force Damage – Sub-Cause:	
- 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:	Unknown
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	Still under investigation, cause of Incident to be determined* (*Supplemental Report required)

PART - H NARRATIVE DESCRIPTION OF THE INCIDENT

SUMMARY OF OPERATIONS JUST PRIOR TO INCIDENT ON 02-14-2011.
A) THREE TURBINES WERE RUNNING WITH A SUCTION PRESSURE OF 688 PSI AND A DISCHARGE PRESSURE OF 1137 PSI.
B) AT 09:11:24 PM, GAS CONTROL PUT A STOP IN T7.
C) AT 09:25:03 PM, ESD WAS ACTIVATED BY FIRE DETECTORS.

THE CAUSE OF THE FIRE IS STILL UNDER INVESTIGATION. INVESTIGATORS AND FORENSIC EXPERTS HAVE BEEN ON SITE. THE FACTS ARE BEING PIECED TOGETHER TO DETERMINE CAUSE.
1) CHECK VALVE ON T7 WAS DAMAGED. CHECK VALVE INTERNALS SEPARATED. CAUSE IS STILL BEING DETERMINED.
2) DISCHARGE VALVE ON T7 DID NOT FULLY CLOSE DURING UNIT SHUT DOWN.
3) 24" ELBOW ON SUCTION TO T7 COMPRESSOR, IN BASEMENT, HAS A 10" RUPTURE IN THE FITTING.

THE DAMAGED FACILITIES HAVE BEEN REPAIRED AND RETURNED TO SERVICE ON 07-16-2011. CAUSE IS STILL UNDER INVESTIGATION.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	GLENN FLOYD
Preparer's Title	TECHNICAL SPECIALIST
Preparer's Telephone Number	662-781-1710
Preparer's E-mail Address	GLENN.FLOYD@BWPMLP.COM
Preparer's Facsimile Number	662-781-1712
Authorized Signature's Name	JACK ADAMS
Authorized Signature Title	DIRECTOR OF DOT COMPLIANCE AND SECURITY
Authorized Signature Telephone Number	713-479-8099
Authorized Signature Email	JACK.ADAMS@BWPMLP.COM
Date	08/30/2011

Appendix D

Operator Failure

Investigation Report

Appendix D Removed

These documents are on file at PHMSA