U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety Administration**

400 Seventh Street, S.W.
Washington, D.C. 20590

SEP 13 2006

Richard D. Hatchett
Vice President, Operations
West Texas Gas, Inc.
211 N. Colorado St.
Midland, TX 79701-4607

Re: CPF No. 4-2004-1007

Dear Mr. Hatchett:

Enclosed is the Final Order issued by the Acting Associate Administrator for Pipeline Safety in the above-referenced case. It makes findings of violation, assesses a civil penalty of $60,000, and specifies actions to be taken to comply with the pipeline safety regulations. The penalty payment terms are set forth in the Final Order. When the civil penalty is paid and the terms of the compliance order completed, as determined by the Director, Southwest Region, this enforcement action will be closed. Your receipt of the Final Order constitutes service under 49 C.F.R. § 190.5.

Sincerely,

James Reynolds
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

VIA CERTIFIED MAIL – RETURN RECEIPT REQUESTED

DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
West Texas Gas, Inc.,	)	**CPF No. 4-2004-1007**
Respondent	)	

FINAL ORDER

On November 13–14, 2001, pursuant to 49 U.S.C. § 60117, a representative of the Research and Special Programs Administration (RSPA) conducted an on-site pipeline safety inspection of Respondent's facilities and records pertaining to the Dalhart District pipeline system in Dalhart, Texas.[1] As a result of the inspection, the Director, Southwest Region, issued to Respondent, by letter dated March 23, 2004, a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent committed violations of 49 C.F.R. Part 192 and proposed assessing a civil penalty of $60,000. The Notice also proposed that Respondent take certain measures to correct the alleged violations.

Respondent responded to the Notice by letter dated April 22, 2004. Respondent contested the allegations and requested a hearing. Respondent provided a supplemental response by letter dated November 2, 2004. The hearing was held on November 9, 2004 in Houston, Texas, after which Respondent submitted additional material for the record on December 9, 2004.

FINDINGS OF VIOLATION

Item 1 in the Notice alleged Respondent violated 49 C.F.R. §§ 192.465(e) and 192.491(c) by failing to reevaluate an unprotected pipeline and determine areas of active corrosion by electrical survey. Section 192.465(e) requires each operator to reevaluate unprotected pipelines and cathodically protect them in areas where active corrosion is found, at least once every 3 years with intervals not exceeding 39 months. An operator must determine areas of active corrosion by electrical survey. If electrical survey is impractical, areas of active corrosion may be

[1] The Norman Y. Mineta Research and Special Programs Improvement Act, Pub. L. No. 108-426, 118 Stat. 2423 (2004), created the Pipeline and Hazardous Materials Safety Administration (PHMSA) and transferred the authority of RSPA exercised under chapter 601 of title 49, United States Code, to the Administrator of PHMSA. *See also* 70 Fed. Reg. 8299, 8301-8302 (2005).

determined by other means, including review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. PHMSA places the burden on an operator using means other than electrical survey to show that electrical survey is impractical.[2] Section 192.491(c) requires each operator to maintain a record of each test, survey, and inspection related to § 192.465(e) for as long as the pipeline remains in service.

The Notice alleged that approximately 78 miles of Respondent's 22-inch Dalhart District pipeline system is bare and areas of active external corrosion are protected using galvanic anodes. The Notice alleged that Respondent performed an electrical survey in 1987, but failed to perform an electrical survey to reevaluate the pipeline once every 3 years.

In its submissions and at the hearing, Respondent acknowledged that it did not perform electrical surveys at 3-year intervals.[3] Respondent contended, however, that electrical surveys are impractical for the Dalhart pipeline and therefore, Respondent's performance of leak detection surveys once or twice each year achieved compliance with § 192.465(e). Respondent explained that electrical surveys are impractical because the pipeline consists of individual 20-foot length segments of pipe joined by rubber dresser couplings that are electrically discontinuous. In order to perform an electrical survey on the line, according to Respondent, a close-interval survey has to be performed. Respondent stated that PHMSA has acknowledged that close-interval surveys are impractical for electronically-discontinuous dresser-coupled pipelines, as stated in an advisory bulletin distributed in 1972.[4]

That advisory bulletin, however, discusses the impracticality of a technique known as "leap-frogging," which is not the same method of electrical survey as a standard close-interval survey technique. In addition, the bulletin explicitly states that other types of electrical equipment are available for dresser-coupled pipelines. Therefore, the advisory bulletin does not support Respondent's contention that electrical surveys are impractical on the Dalhart pipeline.

Respondent further contended that electrical surveys are impractical on the pipeline because the uncoated line is in direct contact with the soil. Respondent stated that environmental conditions, such as changes in soil moisture, temperature, pressure, and other environmental factors invalidate meter readings. However, Respondent did not support this contention with evidence

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[2] Pipeline Safety: Further Regulatory Review; Gas Pipeline Safety Standards, 68 Fed. Reg. 53895, 53897 (2003) (stating that operators of transmission lines "still have to show that electrical surveys are impractical before using alternative methods").

[3] Although Respondent stated in its response that it performed an electrical survey of 66.8 miles in 2001.

[4] Advisory Bulletin No. 72-8, page 4 (issued August 1972). The bulletin states: "The Office of Pipeline Safety does not feel that the use of the two electrode 'leap-frogging' surface potential survey method will provide any useful information in determining where active corrosion is taking place on Dresser-coupled pipelines (insulated joints). [T]here are other types of electrical equipment that will do this job . . . ."

in the record. Respondent also did not explain why those environmental conditions could not be compensated for.

Finally, Respondent explained that electrical surveys are impractical because anodes on the pipeline are in various states of decay, making electrical readings difficult to interpret. However, PHMSA has advised operators that electrical surveys are impractical only where "through no fault or shortcoming of the operator" it is unreasonable or inappropriate to perform an electrical survey.[5] The condition described by Respondent can be remediated (and prevented) by Respondent; therefore, the state of the decaying anodes on the pipeline does not show that electrical survey is impractical on the pipeline.

I find Respondent has not demonstrated that it is unreasonable or inappropriate to perform an electrical survey for the Dalhart pipeline system. Accordingly, I find Respondent violated §§ 192.465(e) and 192.491(c) by failing to reevaluate the unprotected pipeline and determine areas of active corrosion by electrical survey as alleged in the Notice.

Item 2 in the Notice alleged Respondent violated 49 C.F.R. §§ 192.475(a) and 192.491(c) by failing to take sufficient steps to ensure that gas transported in the Dalhart District pipeline system is not corrosive. Section 192.475(a) prohibits pipeline operators from transporting corrosive gas by pipeline, unless the operator has investigated the corrosive effect of the gas and has taken steps to minimize internal corrosion. Section 192.491(c) requires each operator to maintain a record of each test, survey, and inspection related to § 192.475(a) for at least 5 years. The Notice alleged that Respondent tested the gas transported by the pipeline, but not for corrosive properties. The Notice also alleged that Respondent did not have records to demonstrate the gas was not corrosive.

In its written submission and at the hearing, Respondent argued that it is not required to test gas for corrosive properties. However, § 192.475(a) clearly obligates Respondent to ensure that the gas transported is not corrosive.[6] Respondent must document that the gas has been analyzed for corrosive constituents and found not to be corrosive. Proper documentation includes test protocols that have been developed to measure corrosive constituents and documented analysis of the tests results. Respondent must maintain these records pursuant to § 192.491(c).

Respondent stated that the gas was tested for corrosive properties by companies that supplied the gas to Respondent's pipeline. Respondent submitted a letter from one gas supplier, dated August 23, 2004, which recorded the average amount of hydrogen sulfide for deliveries to Respondent for the period of September 2003 through August 2004. However, that letter does not address whether corrosive constituents other than hydrogen sulfide were present in the gas. Moreover, the letter is dated after the Notice was issued and does not address the time period at issue in this

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[5] Corrosion Control Requirements, Deadline and Interpretations, 41 Fed. Reg. 29128, 29129 (1976).

[6] The regulation states "Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion." § 192.475(a).

enforcement action. Respondent did not produce evidence to show that appropriate tests were performed to ensure that the gas was not corrosive. Respondent only claimed that it had confirmed the quality of the gas by participating in telephone calls with the suppliers. Telephone calls do not constitute evidence that the gas transported was not corrosive.

Respondent also argued that it performed periodic physical inspections of the pipeline and never found any internal corrosion caused by corrosive gas. Although physical inspections are an integral part of a successful internal corrosion monitoring program, Respondent must still assess the condition of the gas transported to determine its corrosiveness.[7]

Finally, Respondent stated that since the pipeline is downstream of processing plants and receives no wellhead or gathering system deliveries, there is no opportunity for corrosive gas to be introduced. However, the fact that only processing plants provide gas to the pipeline does not guarantee that the gas provided will not have corrosive properties.

Respondent has not demonstrated that it took sufficient measures to ensure that gas transported by the pipeline was not corrosive. Accordingly, I find Respondent violated §§ 192.475(a) and 192.491(c) as alleged in the Notice.

Item 3 in the Notice alleged Respondent violated 49 C.F.R. §§ 192.553(b) and 192.555(b)(1) by failing to review design, operating, and maintenance history, and previous testing before increasing the maximum allowable operating pressure (MAOP) of the Dalhart pipeline. Section 192.555(b)(1) requires each operator, prior to increasing MAOP or "uprating" a pipeline, to review the design, operating, and maintenance history and previous testing of the segment of pipeline to be uprated. Section 192.553(b) requires each operator retain for the life of the uprated pipeline a record of each investigation conducted, work performed, and pressure test conducted in connection with the uprating.

The Notice alleged that Respondent uprated the Dalhart pipeline by increasing MAOP from 150 psig to 260 psig without conducting the necessary review of design, operating and maintenance history and previous testing of the pipeline. During the inspection, the PHMSA inspector examined Respondent's document titled "MAOP Section." The document shows that the pipeline's "present MAOP" was 150 psig established pursuant to § 192.619(a)(2)(ii) by pressure testing.[8] The same document notes that the proposed MAOP of the segment "to be uprated" was 300 psig, which Respondent planned to establish by a pressure test of 330 psig. At the time of the inspection, Respondent was operating the pipeline at a range of 180 psig to 245 psig and

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[7] *See* 49 C.F.R. §§ 192.475 and 192.477. *See also* Pipeline Safety: Internal Corrosion in Gas Transmission Pipelines, 65 Fed. Reg. 53803 (2000) (notifying gas pipeline operators that they should review their internal corrosion management programs, including among other things, testing for internal corrosion, consideration of specific pipe conditions, and consideration of specific gas conditions, such as "operating temperature and pressure, water content, carbon dioxide and hydrogen sulfide content, carbon dioxide partial pressure, presence of oxygen and/or bacteria, and sediment deposits").

[8] 49 C.F.R. § 192.619(a)(2)(ii) provides that MAOP may be established based on a successful pressure test.

declared the MAOP to be 260 psig. Respondent could not produce records during the inspection to support the increase in operating pressure above 150 psig.

At the hearing and in its response, Respondent stated that the referenced "MAOP Section" document is erroneous. Respondent stated further that no uprating occurred when it increased operating pressure above 150 psig, because MAOP was actually 350 psig. Respondent stated that MAOP had been calculated at 350 psig pursuant to § 192.619(c) based on the highest actual operating pressure to which the pipeline was subjected during the 5 years preceding July 1, 1970.[9] Respondent submitted a document titled "Maximum Transmission Pipeline Working Pressures," dated November 16, 1961, which shows maximum working pressures between 350 psig and 450 psig, and test pressures between 400 psig and 500 psig. However, since the document is dated 1961, it does not show the operating pressures of the pipeline during the 5 years preceding July 1, 1970.

Respondent also submitted an affidavit of its Operations Manager, signed November 2, 2004, which states: "During the five-year period prior to July 1, 1970, the highest actual operating pressure to which the Dalhart System was subjected was 350 psig." Respondent presented no supporting documentation to identify when and where pressures were actually measured on the pipeline during the five-year period prior to July 1, 1970. While the regulations do not explicitly require Respondent to have records of the pressures used to establish MAOP under § 192.619(c), PHMSA must be able to verify that Respondent's entire pipeline was subjected to 350 psig sometime during the five-year period prior to July 1, 1970 in order to substantiate Respondent's claim.[10] I cannot verify that the entire pipeline was subjected to 350 psig during the five-year period prior to July 1, 1970 based on the documentation submitted by Respondent. The affidavit submitted was created after the issuance of the Notice and was executed almost 40 years after the claimed events took place, with no indication of when and where pressures on the pipeline were actually recorded. Therefore, I find Respondent has not demonstrated that MAOP is 350 psig.

Respondent further stated in its response that there would be "economic hardship and permanent, irreparable economic losses to [its] customers" if Respondent is ordered to reduce operating pressure on the Dalhart pipeline.[11] However, the operation of a gas pipeline above the safe MAOP threatens public safety by increasing the risk of failures caused by overpressurization. In the interest of safety, Respondent must operate its pipeline in accordance with applicable safety regulations. Under the Compliance Order, Respondent will have 30 days to determine the appropriate MAOP for the Dalhart pipeline in accordance with § 192.619. Only if it is necessary to ensure compliance, will Respondent have to reduce its current operating pressure.

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9 49 C.F.R. § 192.619(c) provides that MAOP may be established at the highest actual operating pressure to which the pipeline was subjected during the 5 years preceding July 1, 1970.

10 Interpretation of 49 C.F.R. § 192.619(c) (August 4, 1986). Interpretations are available online at http://ops.dot.gov/regs/interp/interp.htm#index.

11 Response at page 3 (April 22, 2004).

I find Respondent did not conduct the necessary review before increasing operating pressure above 150 psig. Accordingly, I find Respondent violated §§ 192.553(b) and 192.555(b)(1) as alleged in the Notice.

Item 4 in the Notice alleged Respondent violated 49 C.F.R. § 192.603(b) by failing to maintain records necessary to operate the Dalhart pipeline pursuant to the MAOP requirements at § 192.619. Section 192.603(b) requires each operator to keep records necessary to administer its procedures established under § 192.605, including those procedures for operating the pipeline in accordance with the requirements of Subpart L of Part 192 (§§ 192.601–192.629). Accordingly, Respondent is required to maintain records that are necessary to operate the pipeline in accordance with the MAOP requirements at § 192.619. The Notice alleged that Respondent's documents listed MAOP at both 150 psig and 260 psig, but Respondent did not have records to substantiate that either amount had been calculated pursuant to § 192.619.

Respondent claimed that the cited provision, § 192.603(b), does not require Respondent to keep records because § 192.619(c) "grandfathered" the operating pressures of pipelines before the regulation took effect. While the regulations do not explicitly require Respondent to have records of the pressures used to establish MAOP under § 192.619(c), if Respondent contends that pressure was calculated under that provision, PHMSA must be able to verify that the entire pipeline was subjected to that pressure sometime during the five-year period prior to July 1, 1970. I have already found that Respondent has not demonstrated that the entire pipeline was subjected to a pressure of 350 psig in accordance with § 192.619(c). Furthermore, Respondent has presented no records to substantiate MAOP in accordance with any other applicable provision at § 192.619.

In its response, Respondent contended that some records pertaining to MAOP may have been misplaced by the former owner of the pipeline prior to Respondent purchasing the pipeline in 1984. However, the transfer in ownership does not excuse Respondent's compliance with pipeline safety regulations applicable to the acquired pipeline system.

Accordingly, I find Respondent violated § 192.603(b) by failing to keep records necessary to operate its pipeline in accordance with the MAOP requirements of § 192.619.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to a civil penalty not to exceed $100,000 per violation for each day of the violation up to a maximum of $1,000,000 for any related series of violations. The Notice proposed a total civil penalty of $60,000 for the violations in Item 1 and Item 3.

49 U.S.C. § 60122 and 49 C.F.R. § 190.225 require that, in determining the amount of the civil penalty, I consider the following criteria: nature, circumstances, and gravity of the violation, degree of Respondent's culpability, history of Respondent's prior offenses, Respondent's ability

to pay the penalty, good faith by Respondent in attempting to achieve compliance, the effect on Respondent's ability to continue in business, and such other matters as justice may require.

Item 1 in the Notice proposed a civil penalty of $40,000 for violating 49 C.F.R. §§ 192.465(e) and 192.491(c). Respondent failed to use electrical survey to reevaluate unprotected pipelines at intervals not to exceed three years. Although Respondent reevaluated the pipeline using leak detection surveys, that method is not a substitute for electrical survey because Respondent did not show that electrical survey is impractical. Failure to properly reevaluate unprotected pipelines may lead to areas of active corrosion that can cause a pipeline to fail. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $40,000 for the violation.

Item 3 in the Notice proposed a civil penalty of $20,000 for violating 49 C.F.R. §§ 192.553(b) and 192.555(b)(1). Respondent failed to review design, operating, and maintenance history, and previous testing before increasing the operating pressure of the Dalhart pipeline above the listed MAOP. By increasing the operating pressure above MAOP without verifying in accordance with § 192.555 that the pipeline could be safely operated at a higher pressure, Respondent exposed the pipeline to the risk of overpressurization, which can result in a pipeline failure. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $20,000 for the violation.

Respondent is assessed a total civil penalty of **$60,000**. Respondent has the ability to pay this penalty without adversely affecting its ability to continue in business.

Payment of the civil penalty must be made within 20 days of service. Federal regulations (49 C.F.R. § 89.21(b)(3)) require this payment be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-120), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 25082, Oklahoma City, OK 73125; (405) 954-4719.

Failure to pay the $60,000 civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9, and 49 C.F.R. § 89.23. Pursuant to those authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a United States District Court.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to the violations. Under 49 U.S.C. § 60118(a), each person who engages in the transportation of gas or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under Chapter 601. Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations. Respondent must—

1. Submit for approval procedures for performing an electrical survey in accordance with 49 C.F.R. § 192.465(e) on the Dalhart District pipeline system. Perform the electrical survey in accordance with the approved procedures and submit the results to the Director, Southwest Region. Complete this Item within 90 days of receipt of this Order.

2. Submit for approval protocols for testing the gas transported by the Dalhart District pipeline to determine if the gas is corrosive. Initiate testing of the gas in accordance with the approved procedures and submit the results to the Director, Southwest Region. If the gas is found to be corrosive, implement a mitigative program to minimize internal corrosion in accordance with 49 C.F.R. § 192.475. Complete this Item within 30 days of receipt of this Order.

3. Determine the MAOP of the Dalhart District pipeline system in accordance with 49 C.F.R. § 192.619 and submit the results and supporting documentation to the Director, Southwest Region. If necessary, reduce operating pressure of the pipeline system to ensure that the pipeline system is operated within MAOP in accordance with 49 C.F.R. § 192.619. Complete this Item within 30 days of receipt of this Order.

4. Information required to be submitted pursuant to this Order, including documentation that each Item has been completed, shall be submitted to the Director, Southwest Region, Pipeline and Hazardous Materials Safety Administration, 8701 S. Gessner Dr., Suite 1110, Houston, TX 77074-2949.

The Director, Southwest Region, may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent demonstrating good cause for an extension.

Failure to comply with this Order may result in administrative assessment of civil penalties up to $100,000 per day for each violation and in referral to the Attorney General for appropriate relief in a district court of the United States.

Under 49 C.F.R. § 190.215, Respondent has a right to submit a Petition for Reconsideration of this Final Order. The petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issue(s). The filing of the petition automatically stays the payment of any civil penalty assessed. All other terms of the order, including any required corrective action, remain in full effect unless the Associate Administrator, upon request, grants a stay. The terms and conditions of this Final Order are effective on receipt.

Theodore L. Willke
Acting Associate Administrator
for Pipeline Safety

SEP 13 2006

Date Issued