U.S. Department
of Transportation

Pipeline and
Hazardous Materials Safety
Administration

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 20, 2010

Mr. Mark Cunningham, P. E.
Vice President, Operations
Holly Energy Partners
100 Crescent Court, Suite 1600
Dallas, TX 75201-6927

CPF 4-2010-5005

Dear Mark Cunningham:

On November 30 though December 3, 2009, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) inspected your River and Trust Pipelines in Big Spring, Abilene, and Wichita Falls, TX, pursuant to Chapter 601 of 49 United States Code.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violation(s) are:

1. §195.310 Records.

(a) A record must be made of each pressure test required by this subpart, and the record of the latest test must be retained as long as the facility tested is in use.

Holly Energy Partners (HEP) informed PHMSA representatives that records of the pressure test for three of eleven pipeline segments were missing, and that HEP was attempting to locate them. HEP is required to retain these records for as long as the facility tested is in use.

A spreadsheet titled Pipeline Maximum Operating Pressures summarizing the pipeline segment test pressures and MOPs was provided by HEP to the PHMSA representatives during the records review at the HEP Big Springs office location on November 30, 2009. The spreadsheet listed eleven Trust Pipeline System pipeline segments and relevant materials and testing information for use in the calculation of the MOP. The spreadsheet indicated the following three segments had no test records:

System	Segment
X-6	Big Spring to Hawley
6 / 8	Colorado City to Merkel
6 / 8	Throckmorton to Archer

The operator voluntarily reduced the operating pressure to 80% of the normal operating pressure prior to the PHMSA inspection. Additionally, HEP indicated that they were continuing to attempt to locate these records, and that if they were not located, it was their intention to re-test these three pipeline segments.

HEP must have records conforming to 49 CFR 195.310 that demonstrate the three segments identified above have been pressure tested in accordance with Subpart E of 49 CFR 195.

2. §195.402 Procedural manual for operations, maintenance, and emergencies.

(c) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(5) Analyzing pipeline accidents to determine their causes.

(6) Minimizing the potential for hazards identified under paragraph (c)(4) of this section and the possibility of recurrence of accidents analyzed under paragraph (c)(5) of this section.

HEP had two accidents that were reportable to PHMSA, one in 2005 and a second in 2006. Both accidents were a result of second party excavation by the same contractor performing remediation work on HEP's pipeline. HEP was unable to produce a written accident investigation and could not demonstrate revisions to their damage prevention program resulting from any investigations related to either accident.

HEP could not demonstrate that an investigation for the accident reported under PHMSA Hazardous Liquid Accident Report ID 20050342 occurred. HEP could not produce documents related to the determination of the cause and minimizing the recurrence, and the procedures failed to achieve the desired results as demonstrated by the second event reported under PHMSA Hazardous Liquid Accidents Report ID 20060309. Similarly, HEP could not demonstrate that an investigation had occurred for this accident.

3. §195.402 Procedural manual for operations, maintenance, and emergencies.

> **(13) Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.**

Two second party excavation accidents occurred in 2005 and 2006, but HEP was unable to demonstrate that a procedural review or revision to the damage prevention procedure **23.1 HEP-O&M-195.442(Damage Prevention Program)** had occurred. The excavation accidents were by the same contractor, performing similar work and occurred a year apart. These events indicate potential procedural deficiencies in multiple areas relating to Contractor Oversight, Operator Qualifications, Excavation and Trenching, Damage Prevention, and Accident Investigation, yet no documentation of procedural reviews for any of these procedures could be provided, and the change log maintained to document that procedures are reviewed indicated no revisions to these procedures resulting from an accident investigation or effectiveness review.

4. §195.410 Line markers.

> **(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:**
>
> > **(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.**

HEP has placed line markers along fence lines at road crossings, but has not consistently placed them in the right of ways of rural locations. Looking from the roadway in several locations identified in the field inspection, the PHMSA inspector, and the HEP Compliance Manager were unable to identify the location of the pipeline, or its route. This was particularly noticeable in remote locations. The requirement of 49 CFR 195.410 does not make a distinction between rural or populated areas and the pipeline should be accurately markers so that its location is known.

5. **§195.432 Inspection of in-service breakout tanks.**

> **(b) Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).**
>
> **(d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.**

HEP acquired the Wichita Falls Terminal facilities in 2005. Internal inspection summary reports were provided to HEP from the previous owner that indicated an API Standard 653 (API 653) internal inspection was performed on tanks 8 and 9 at the Wichita Falls Terminal in 1996. HEP relied upon these inspection reports to establish the next internal inspection intervals and set the internal inspection intervals to the API 653 maximum of 20 years for Tanks 8 and 9. Based upon this interval, HEP has not performed an internal inspection of these two tanks since 1996, and an internal inspection was scheduled for both tanks for the year 2016.

The inspection report of Tank 8, dated 03-04-96, indicated the inspection was due to suspected tank bottom leakage. Additionally, a change of product from the product that had been stored in this tank from diesel to jet fuel was anticipated at the time of the 1996 internal inspection. The report included a sketch of the floor inspection results and indicated 8 holes in the tank bottom. The report did not indicate whether the holes were from topside or bottom-side corrosion. Also, the inspection did not establish a topside or bottom-side corrosion rate, and HEP could not provide the inspectors with a corrosion rate for the calculation of the inspection interval. Repairs to the tank bottom were recommended in the report, but documentation demonstrating the recommended repairs had been made was not available. The report recommended installation of a tank bottom topside coating to prevent further corrosion. Records of the product, its installation or service life were not available.

API 653 Section 6.4.2 describes the method for establishing the inspection intervals for internal inspections. Section 6.4.2 requires the calculation of the internal inspection intervals in accordance with Section 4.4.7 of the standard, with a maximum internal inspection interval of 20 years. If, however, the corrosion rates are unknown, the maximum inspection interval is not to exceed 10 years, unless similar service experience is available to estimate the bottom plate thickness at the next inspection.

HEP failed to demonstrate that they had established a corrosion rate for the tank bottoms of Tanks 8 and 9, and exceeded the 10 year maximum internal inspection interval for unknown corrosion rates in 2007. Additionally, HEP did not have similar service experience, or procedures to apply similar service experience available to make this inspection interval determination.

HEP failed to inspect Tanks 8 and 9 at the Wichita Falls Terminal within the maximum 10 year interval in accordance with API 653.

6. §195.571 What criteria must I use to determine the adequacy of cathodic protection?

> **Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP 0169 (incorporated by reference, *see* §195.3).**

The records for the pipe to soil readings on the River and Trust pipelines for the years 2005 to 2009 were reviewed by the PHMSA representatives. During this review, the following readings were observed to not meet the minimum criteria established by HEP for cathodic protection. Additionally, when further questioned, HEP indicated that there was no other criteria that applied to establishing the minimum acceptable values for the River and Trust specific pipe to soil readings than a pipe to soil reading of -0.850 V ON because they had not performed a depolarized survey to establish the criteria that would allow application of the 250 millivolt criteria in their procedure.

HEP's procedures for corrosion control adopt two criteria for the cathodic protection of its pipelines. HEP's procedure number O&M – 195.563 Cathodic Protection states that:

"Sufficient current must flow from soil to pipe to maintain a constant voltage difference at the soil-metal interface of 0.25 volt (approximately -0.85 volt between pipe and copper sulfate electrode in contact with soil) or more."

The following readings failed to meet criteria:

Reading Date	Milepost	Location	Pipe to Soil (V) Read
10/27/2005	**103.200**	**TEPPCO X-ing**	-0.794
12/08/2006			-0.776
12/28/2007			-0.799
09/30/2008			-0.593
10/27/2005	**103.400**	**Co. Rd Rectifier TR #103**	-0.843
12/08/2006			-0.829
12/28/2007			-0.823
09/30/2008			-0.608
11/02/2005	**103.401**	**TEX-NEW MEX X-ING**	-0.841
12/08/2006			-0.832
12/28/2007			-0.825
109/30/2008			T/L Destroyed
11/02/2005	**103.900**	**Conoco X-ing**	-0.810
12/08/2006			-0.852

12/28/2007			-0.795
09/30/2008			-0.502
11/02/2005	**110.000**	**Conoco X-ing**	-0.772
12/09/2006			-0.751
12/28/2007			-0.795
11/02/2005	**110.001**	**Co. Rd.**	-0.768
12/09/2006			-0.746
11/02/2005	**110.400**	**Conoco X-ing (Field)**	-0.844
12/09/2006			-0.811
11/02/2005	**111.000**	**FM Road (South)**	-0.779
12/09/2006			-0.776
11/02/2005	**111.700**	**FM 1954**	-0.859
12/09/2006			-0.764

HEP failed to demonstrate adequate cathodic protection levels were maintained for the locations identified above by failing to meet the criteria specified in their corrosion control procedures. HEP has corrected the conditions identified herein with the installation of two additional rectifiers and all readings taken in 2009 were at or above the minimum specified criteria.

7. §195.573 What must I do to monitor external corrosion control?

> **e)** ***Corrective action.*** **You must correct any identified deficiency in corrosion control as required by §195.401(b).**

During the interview at the Big Spring office on December 1, 2009, HEP indicated that their criteria for effective cathodic protection on the River and Trust Pipelines was – 0.850 V ON, and that the system had not had electrical surveys preformed to establish the native potentials for use with -250 mV criteria. This was confirmed by PHMSA's review of HEP's procedure HEP-H-195-002 - Corrosion Control.

During the discussion of these readings, HEP also stated that the appropriate timing for corrective actions related to deficient pipe to soil readings was one year, or prior to the next annual inspection, and the corrective action was that the pipe to soil reading level should be brought up to the minimum criteria. HEP could not demonstrate information contained within their corrosion procedures that specified the timing of corrective actions or the definition of "prompt" as it pertained to the correction of pipe to soil readings that failed to meet minimum criteria.

The records for all test post pipe to soil readings on the River and Trust for the years 2005 to 2009 were reviewed by PHMSA representatives. During this review, the following locations were observed to not meet the minimum criteria established by HEP for cathodic protection for more than one inspection cycle. The readings that are shown in the following list are included to establish when these locations were brought into compliance with the minimum criteria necessary to demonstrate adequate cathodic protection.

Reading Date	Milepost	Location	Pipe to Soil (V) Read
11/03/2009	**103.200**	**TEPPCO X-ing**	-1.522
11/03/2009	**103.400**	**Co. Rd Rectifier TR #103**	-1.974
11/03/2009	**103.401**	**TEX-NEW MEX X-ING**	-1.845
11/03/2009	**103.900**	**Conoco X-ing**	-1.434
09/30/2008	**110.000**	**Conoco X-ing**	-1.246
12/28/2007	**110.001**	**Co. Rd.**	-1.412
12/28/2007	**110.400**	**Conoco X-ing (Field)**	-1.929
12/28/2007	**111.000**	**FM Road (South)**	-1.801
12/28/2007	**111.700**	**FM 1954**	-1.768

HEP failed to promptly evaluate and correct the deficiencies in corrosion control indicated by the pipe to soil readings listed above. All readings appeared have been brought up to minimum levels as demonstrated by the readings taken during the 2009 annual survey.

Warning Items

With respect to items 3 and 4, we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to promptly correct these item(s). Be advised that failure to do so may result in HEP being subject to additional enforcement action.

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violation(s) and has recommended that you be preliminarily assessed a civil penalty of $92,500 as follows:

Item number	PENALTY
2	$22,500
6	$35,000
7	$35,000

Proposed Compliance Order

With respect to items 1 and 5 above, pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Holly Energy Partners. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Response to this Notice

Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

In your correspondence on this matter, please refer to **CPF 4-2010-5005** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

Enclosures: *Proposed Compliance Order*
Response Options for Pipeline Operators in Compliance Proceedings

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to Holly Energy Partners (HEP) a Compliance Order incorporating the following remedial requirements to ensure the compliance of HEP with the pipeline safety regulations:

1. In regard to Item Number 1 of the Notice pertaining to missing pressure testing records, HEP shall maintain the 20% pressure reduction for the segments identified below until such time HEP provides records to PHMSA that conform to the requirements of 49 CFR 195.310 and demonstrate the three segments identified below have been pressure tested in accordance with Subpart E of 49 CFR 195.

System	Segment
X-6	Big Spring to Hawley
6 / 8	Colorado City to Merkel
6 / 8	Throckmorton to Archer

Additionally, HEP's relevant pressure testing and record retention procedures should be expanded to include the accountabilities, process and storage location to ensure that critical records are retained for as long as the facility tested is in use.

2. In regard to Item Number 5 of the Notice pertaining to exceeding the maximum API Standard 653 internal inspection interval for breakout tanks numbers 8 and 9 at Wichita Falls Terminal, HEP shall remove the tanks from service until such time that an API 653 internal inspection has been performed by a qualified party, and all deficiencies identified during the inspection requiring action have been addressed.

3. The timing for Items 1 and 2 is proposed as follows:

Item 1: Provide pressure test records to PHMSA, SW Region Director no later than 180 days from the Final Order.

Item 5: Remove tanks 8 and 9 from service no later than 30 days from the Final Order. These tanks shall remain out of service until the inspection has been performed and documentation submitted to the SW region Director and approval to return to service has been granted.

4. HEP shall maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to R. M. Seeley, Director, SW Region, Pipeline and Hazardous Materials Safety Administration. Costs shall be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.