NOTICE OF AMENDMENT

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 4-2010-5004M

Dear Mr. Cunningham:

On November 30 through December 3, 2009, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) inspected various Holly Energy Partners (HEP) procedures for operations and maintenance of the River and Trust pipeline system and associated facilities in Big Spring, Abilene, and Wichita Falls, TX, pursuant to Chapter 601 of 49 United States Code

On the basis of the inspection, PHMSA has identified apparent inadequacies within HEP's plans or procedures, as described below:

1. §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's post accident review procedures should be revised and expanded to identify which accidents shall receive a post accident investigation, how the investigation should be conducted, how the investigation shall be documented and the results communicated, and how the possibility of recurrence of the accidents that are analyzed will be minimized.

2. §195.401 General requirements.

(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

HEP's Corrosion Control procedures found in **HEP-O&M-195.555 – 589 (Corrosion Control) Section 2. Procedure** require the Cathodic **S**upervisor to *"Identify any deficiencies in corrosion control and take necessary steps to correct the deficiencies as required by § 195.401(b)."* HEP personnel were asked about the definition of "reasonable time," and where its definition could be found in the HEP procedures. The HEP personnel indicated that this is not defined within the HEP procedures.

Pipe to soil readings were below HEP's criteria for a period of four annual reading cycles in the areas of Mileposts 103 to 111 on the Trust Pipeline. This exceeded a reasonable time before the pipe to soil readings were brought to an acceptable level, as defined by HEP's criteria for the potential differences between the buried pipe and the soil. During interviews of HEP corrosion and operations personnel, it was clearly understood that the expectation of a reasonable time for corrective action was prior to the next required inspection. For annual surveys, this would have been one year, not to exceed fifteen (15) months, or prior to the next annual survey. This answer from HEP personnel is consistent with PHMSA's expectations of a reasonable timeframe. However, the readings identified as not meeting criteria were not brought into compliance within a reasonable time.

HEP's procedures should be revised to define "reasonable time" in context with the appropriate activities that could affect safe operations to ensure that conditions are corrected in accordance with 49 CFR 195.401(b).

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.

HEP's review of work done by operator personnel to determine the effectiveness of the procedures was not documented. Two excavation accidents occurred, 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.

HEP's procedure for carrying out a review to determine the effectiveness of its operation and maintenance procedures should be revised to expand the detailed requirements of the review, the manner in which the review is documented and the necessity for taking corrective actions where deficiencies are found.

4. §195.404 Maps and records.

> **(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:**
>
> > **(4) The diameter, grade, type and nominal wall thickness of all pipe.**
>
> **(c) Each operator shall maintain the following records for the periods specified:**
>
> > **(1) The date, location, and description of each repair made to pipe shall be maintained for the useful life of the pipe.**

HEP is in the process of digitizing the records of the pipeline system to include the information required by 49 CFR 195.404(a)(4) and (c)(1) in a Geographical Information System (GIS) database. Newly generated alignment sheets from the GIS database indicated the pipeline route and had additional information regarding the pipeline materials. However, the information for pipeline materials was stated to be "Unknown" for pipeline specifications on the alignment sheets. Upon request, HEP operations personnel were able to produce additional records that identified the pipe materials. However, upon review of the pipeline records for the extensive repair program carried out by HEP in 2006, numerous inconsistencies were noted in the pipeline specifications with respect to diameter and wall thickness. Further, these repairs were not identified in the newly generated alignment sheets or the records provided in lieu of the GIS alignment sheets. While HEP was able to provide records of these materials, the specific locations were not discernable by the various records provided for PHMSA's review, and the accuracy was inconsistent as observed by the PHMSA representatives.

HEP should modify their procedures to ensure the accurate mapping and identification of the pipe diameter, grade, type and nominal wall thickness are maintained, particularly with the extensive effort to digitize the records and the potential for data inconsistencies that was observed. Consideration of better quality control of the records reviewed by PHMSA's representatives would benefit HEP in their transition from paper to electronic records to ensure the accuracy and retention of this information. Specific examples of the data inconsistencies were identified to the operations personnel with respect to the pipe replacements resulting from the ILI program in 2006 and 2007.

5. §195.405 Protection against ignitions and safe access/egress involving floating roofs.

> **(b) The hazards associated with access/egress onto floating roofs of in-service aboveground breakout tanks to perform inspection, service, maintenance or repair activities (other than specified general considerations, specified routine tasks or entering tanks removed from service for cleaning) are addressed in API Publication 2026. After October 2, 2000, the operator must review and consider the potentially hazardous conditions, safety practices and procedures in API Publication 2026 for inclusion in the procedure manual (§195.402(c)).**

HEP's procedure incorporated by reference, a copy of API Publication 2026, however, a copy of the API publication was not available and the operations personnel were not aware of its contents. HEP could not demonstrate that a review of the potentially hazardous conditions, safety practices and procedures had occurred. HEP contended that the Caution statement found in **HEP Procedure 18.1 HEP-O&M-195.432 (Inspection of in-service breakout tanks)** fully addressed the requirements of API Publication 2026. The incorporation by reference fails to fully address the inclusion in the procedure manual, particularly when a copy was not available to the people that would need to follow it, and the Caution statement that HEP included does not fully address the subjects covered in API Publication 2026.

HEP should review and consider the potentially hazardous conditions, safety practices and procedures found in API Publication 2026. Upon completion of this review, HEP should revise their procedures to specifically address the conditions, practices and procedures in their procedure manual, in lieu of incorporation by reference of the API Publication. These revisions are intended to clearly identify the requirements for safe work practices and identification of hazardous conditions in HEP's procedures, and further ensure the proper training of HEP personnel and contractors using these HEP procedures. HEP should also consider the implications of these revisions to their Operator Qualification program's covered tasks and abnormal operating conditions.

6. §195.432 Inspection of in-service breakout tanks.

> **(a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank.**
>
> **(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).**
>
> **(c) Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.**

(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's procedure **HEP-O&M-195.432 (Inspection of In-Service Breakout Tanks)** states the above requirements, but lacks detail to ensure that the inspection intervals are calculated in accordance with API RP 653. The inspection interval requirements were identified in **HEP's Corrosion Control procedure Section 6.3.2**, but there is no cross-reference to the tank procedure, and neither procedure provides adequate detail to ensure that the calculation is performed correctly. HEP did not identify or distinguish the topside and bottom-side corrosion rates for multiple tanks at Wichita Falls Terminal. As a result, two tanks exceeded the 10 year maximum internal inspection interval specified by API RP 653. The HEP procedure lacks details and specificity to ensure the inspection report provides the necessary information for the calculation of the internal inspection interval from the corrosion rates.

HEP should revise their procedure **HEP-O&M-195.432** to include the specific steps to calculate the internal inspection intervals, the requirements for when a zero corrosion rate can be assumed, and the maximum intervals to ensure that the maximum internal inspection intervals are not exceeded for in-service breakout tank inspections.

7. §195.440 Public awareness.

(d) The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

HEP's public awareness brochure did not clearly identify the steps for the use of one-call notification centers, the use of the national 811 telephone number, and provided conflicting information about the proper entity to contact prior to the initiation of excavation activities.

HEP should revise their public awareness brochure to clearly identify the correct steps and contact information prior to excavation and in the event of an emergency in their written public awareness materials.

8. §195.442 Damage prevention program.

(a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline shall carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

HEP's **Procedure 23.1 HEP-O&M-195.442 (Damage Prevention Program)** does not require inspection of pipelines that an operator has reason to believe could be damaged by excavation activities as frequently as necessary during and after activities to verify the integrity of the pipeline. HEP had two second-party excavation accidents that occurred while an HEP contractor was excavating the pipeline. Both accidents were reportable and were reported on Hazardous Liquid Accident Reports ID 20050342 and Report ID 20060309.

HEP's damage prevention procedures should be revised to require the inspection of pipelines in accordance with 49 CFR 195.442(c)(6).

9. §195.573 What must I do to monitor external corrosion control?

(d) *Breakout tanks.* You must inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. However, this inspection is not required if you note in the corrosion control procedures established under §195.402(c)(3) why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

HEP's procedure for corrosion control 6.3.1 identifies their tank bottom "*criterion were developed in accordance with API RP 651.*" However, the HEP procedures for tank bottom protection do not account for IR drop, and specify "*a minimum of -.85 volt should be maintained at the shell.*" API RP 651 provides additional guidance for tank bottom criteria that is not contained in HEP's procedure, and a copy of API RP 651 was not available, nor was the corrosion technician familiar with the document. API RP 651 specifically requires measurement techniques for determining the effectiveness of cathodic protection on a tank bottom that are not addressed by HEP's procedures.

HEP's procedure for interference/stray current detection and mitigation 6.2.3 does not address tanks or terminal facilities as described in Sections 4, 7 and 10 of API RP 651, and the methods for detection and mitigation identified in HEP's procedure 6.2.3 appear inadequate for terminal facilties and above ground storage tanks.

HEP's procedures do not discuss the replacement or repair of tank bottoms and the possibility of shielding of CP in the cases where a tank bottom is replaced without the removal of the old tank bottom. The HEP corrosion technician was unaware of this phenomenon, and had not previously been aware of the possibility of shielding in this case. The content of API RP 651 should be thoroughly addressed in the HEP corrosion control procedures and the associated training of the personnel responsible for tank bottom corrosion control monitoring.

HEP stated that because they have cathodic protection on their tanks, they may assume a zero corrosion rate for the tank bottom-side corrosion rate for the calculation of the internal inspection interval. However, without additional information, calculation or readings, it appears that HEP is not prudent in the use of a zero bottom-side corrosion rate, particularly without addressing all of the requirements of API RP 651 in their tank bottom corrosion control monitoring.

HEP should revise their corrosion control procedures for tank bottoms to more completely incorporate the requirements of API RP 651, and ensure that the training of the corrosion personnel includes the identification of API RP 651 and its requirements. Further, the procedures should clearly identify the acceptable circumstances for when the use of a bottom side corrosion rate of zero may be used in the in-service breakout tank internal inspection interval calculation.

10. §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). However, if the deficiency involves a pipeline in an integrity management program under §195.452, you must correct the deficiency as required by §195.452(h).**

HEP's procedure **HEP-O&M-195.555 – 589 (Corrosion Control)** identifies the requirement for corrective action required by CFR 195.573(e) by restating the exact code language, but does not provide examples of corrective actions or the type of deficiencies that require corrective actions for all corrosion control monitoring activities, and specifically for pipe to soil readings not meeting minimum criteria, in its procedures under 6.2.2. Instead, HEP's procedure state that *"if -.85V is not achieved, further follow-up action will be taken to achieve adequate protection."*

HEP's procedure should be revised to ensure appropriate corrective action is taken within a reasonable time, and as required by §195.401(b), and specifically when the minimum pipe to soil potential criteria is not achieved.

11. §195.579 What must I do to mitigate internal corrosion?

> **(a)** ***General.*** **If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.**

HEP's corrosion procedures restated the code language of 49 CFR 195.579, but did not identify the procedure to carry out the requirement. Further, HEP could not provide documentation that an investigation had been conducted. HEP had a coupon monitoring program and used corrosion inhibitor at multiple locations in its system, but had no criteria for the corrosion rates, or the amounts of inhibitor to be injected. The basis for the internal corrosion control monitoring could not be demonstrated by study or procedure.

The coupon monitoring reports indicated internal corrosion, but when interviewed, the operations and corrosion personnel could not identify parameters as to whether the metal loss rates were high or low or if any action should be taken. **Corrosion Control Section 6.5** of HEP's procedures did not contain criteria or steps to take to mitigate internal corrosion.

HEP should modify its procedures to ensure that an investigation is carried out and that the steps to adequately mitigate internal corrosion are incorporated into their procedures for internal corrosion control.

12. §195.579 What must I do to mitigate internal corrosion?

> **(d) *Breakout tanks.* After October 2, 2000, when you install a tank bottom lining in an aboveground breakout tank built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the lining in accordance with API Recommended Practice 652. However, installation of the lining need not comply with API Recommended Practice 652 on any tank for which you note in the corrosion control procedures established under §195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 652 is not necessary for the safety of the tank.**

HEP's internal corrosion control procedures in Section 6.5 do not address breakout tanks. The corrosion monitoring of tank bottoms is addressed in Section 6.3.1, however, there is no distinction between internal and external corrosion control monitoring mentioned.

HEP did not have a copy of API 652, and the requirements of API RP 652 were not incorporated into the corrosion control procedures reviewed by PHMSA. If the requirements of API RP 652 have been incorporated in another portion of HEP's design, construction of specification documents, the following requirement may be satisfied in that manner.

HEP's procedures should be revised to identify the internal corrosion control requirements for breakout tanks, and to clearly distinguish between internal corrosion control and external corrosion control monitoring for tank bottoms. Additionally, if HEP wishes to use the application of coatings in accordance with API 652 as the basis of assumption of a zero corrosion rate for the topside corrosion rate in the internal inspection interval calculation, additional information about the coating life and installation practices should be incorporated into HEP's procedures.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. 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.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 90 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 4-2010-5004M** 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

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*