Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE CRUDE PIPELINES, LLC

April 26, 2012

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Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety
8701 South Gessner, Suite 1110
Houston, TX 77074

Attn: Mr. Rodrick M. Seeley
Director, Southwest Region

RE: Notice of Probable Violation and Proposed Compliance Order
dated March 12, 2012 (CPF 4-2012-5007)
Enterprise Crude Pipelines LLC (Enterprise) Inspection, April, 2011

Dear Mr. Seeley,

This letter is in response to the Pipeline and Hazardous Materials Safety Administration (PHMSA) Notice of Probable Violation and Proposed Compliance Order dated March 12, 2012.

**Item #1 - 195.264 Impoundment, protection against entry, normal/emergency venting or pressure/vacuum relief for aboveground breakout tanks.**

**(a) A means must be provided for containing hazardous liquids in the event of spillage or failure of an aboveground breakout tanks.**
**(b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the aboveground breakout tanks specified:**
**(1) For tanks built to API Specification 12F, API Standard 620, and others (such as API Standard 650 or its predecessor Standard 12C), the installation of impoundment must be in accordance with the following sections of NFPA 30:**
**(i) Impoundment around a breakout tank must be installed in accordance with section 4.3.2.3.2; and**
**(ii) Impoundment by drainage to a remote impounding area must be installed in accordance with section 4.3.2.3.1.**
**(2) For tanks built to API 2510, the installation of impoundment must be in accordance with section 5 or 11 of API 2510 (incorporated by reference, see §195.3).**

*Enterprise (the Operator) did not have documentation (surveys, calculations) verifying that the containment dike volume at the East Cushing Terminal met the applicable NFPA 30 requirements after constructing additional tanks within the diked area as recently as 2006. The documentation was requested during the inspection but not provided by the Operator. The Enterprise procedure EGS E-6310, Secondary Containment & Leak*

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*Detection, Section 5.0, Diking, specifies requirements but the Operator was not able to produce documentation showing that these procedures had been followed.*

Enterprise response to Item #1:

The EPCO, Inc procedure "EGS E-6310, Storage Tank Guidelines – Secondary Containment & Leak Detection" which was in effect at the time of the April 2011 inspection has now been replaced with STD.5602, Tank Farm Design. A survey of the secondary containment was performed and additional dike modifications were completed subsequent to the survey. The current survey verifies that the diked area at the East Cushing Terminal exceeds the requirements of NFPA 30 as referenced in STD.5602. The secondary containment diagram is attached for reference.

Requirements of the Proposed Compliance Order have been met and closure of this item is hereby requested.

**Item #2 - 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 must inspect the physical integrity of in-service atmospheric and low pressure steel aboveground breakout tanks according to API Standard 653 (incorporated by reference, see § 195.3). 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.**

*I. The corrosion rate used by Enterprise to establish the external inspection intervals was not based on actual shell thickness measurements for a given tank or a documented similar service assessment performed according to the requirements the version of API 653, Appendix H.*
*According to interviews performed during the inspection and email correspondence from Enterprise, a corrosion rate of 0.003 inches per year was used if there was no known corrosion rate. The incorporated version of API 653 requires that the external inspection "... be conducted at least every 5 years or RCA/4N years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mils, and N is the shell corrosion rate in mils per year) whichever is less." Therefore, an Operator must determine an actual corrosion rate through measurement or determine a corrosion*

*rate based on a similar service study performed according to the requirements of API 653 Appendix H to establish the external inspection interval.*

*II. Pertaining to the Operator's procedural requirements for external inspections, at the time of the inspection or afterwards, Enterprise presented several breakout* tank *inspection procedures that included external inspection requirements, so it is not clear which procedure(s) the Operator used. The procedures included Enterprise Products STD.9502, Inspection and Testing of Aboveground Storage Tanks, EPCO, Inc., STD.9503, DOT Breakout Tank Integrity Testing, and EPCO, Inc., EGS E-6320, Tank Inspection Repair, Alteration and Reconstruction. The wording for the external inspection requirements varied between procedures but each intended to convey the external inspection requirements of API 653, although sometimes incorrectly. For example, EPCO, Inc., STD.9503 states that a risk-based inspection assessment may be used to establish the external inspection interval. However, the version of API 653 incorporated by reference states in Section E.3, Technical Inquiry Responses, 653-1-02/03, "RBI can be applied to internal inspection intervals only."* If *the operator followed this procedure, it would not be consistent with the requirements of Part 195 for external breakout tank inspections.*

*III. Also, at the time of the inspection, Enterprise had set the ultrasonic thickness inspection intervals to the maximum of 15 years. For ultrasonic inspections the version of API 653 incorporated by reference states, "When the corrosion rate is not known, the maximum interval shall be 5 years.*
*Corrosion rates may be estimated from tanks in similar service based on thickness measurements taken at an interval not exceeding 5 years." API 653 goes on to state "When the corrosion rate is known, the maximum interval shall be the smaller of RCA/2N years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mils, and N is the shell corrosion rate in mils per year) or 15 years." According to interviews with Enterprise personnel during the inspection and email correspondence from Enterprise, the operator did not determine actual corrosion rates or perform a similar service assessment to establish a corrosion rate that would provide the basis allow the ultrasonic corrosion inspection interval to be 15 years. Enterprise has notified PHMSA after the inspection that it was changing its ultrasonic inspection intervals to 5 years.*

*IV. Pertaining to internal breakout tank inspections, Enterprise employs a risk-based inspection (RBI) methodology to determine the internal inspection intervals. This is allowed by section 6.4.3 of the version of API 653 incorporated by reference. However, the analysis methods used to determine the product side, soil side, and external corrosion rates and the accuracy of these methods and corrosion rates must be considered in the risk-based methodology. Interviews during the inspection as well as email correspondence from Enterprise did not provide adequate justification for the basis of the floor corrosion rates used in the risk-based methodology (from actual measurements or similar service) to determine the internal inspection intervals. As an example of the issue, the API 653 inspection report for* tank *1003 in Cushing, OK, performed in April-May*

*2009, states "A new bottom is to be installed (per client). Consideration should be given to inspecting the new bottom within ten (10) years to establish a corrosion rate (ref. API 653, Para. 6.4.2.2)." Despite not having a measured corrosion rate for the floor, a documented similar service assessment, or other justified means for the floor corrosion rates used, Enterprise set the internal inspection interval for tank 1003 to 15 years as shown on the Tank Data form completed by the Operator. According to API 653, section 6.4.3, Alternative Internal Inspection Interval, the Operator must consider in an RBI assessment, "c. The methods used for determination of the shell and bottom plate thickness," "d The availability and effectiveness of the inspection methods and quality of the data collected," and "e. The analysis methods used to determine the product side, soil side, and external corrosion rates and the accuracy of these methods and corrosion rates."*

Enterprise Response to Item #2:

I. At the time of the April 2011 inspection, Enterprise was using RBI for external inspection intervals as allowed in the incorporated version of API 653 in 6.4.3 "......After an effective RBI assessment is conducted, the results can be used to establish a tank inspection strategy and better define the most appropriate inspection methods, appropriate frequency for **internal**, **external** and **on-stream** inspections......." based on actual shell thickness measurements. See the attached API 653 inspection reports for reference.

After the April 2011 inspection, external inspection intervals were adjusted from RBI to the lesser of 5 years or RCA/4N, based on actual shell thickness measurements, as documented in STD.9503 Inspection and Testing of Atmospheric and Low-Pressure DOT Breakout Tanks.

Following the modification of STD 9503, no external inspections intervals exceed the lesser of 5 years or RCA/4N, based on actual shell thickness measurements; please refer to the attachment entitled Inspection Frequency Summary and the attached API 653 inspection reports for reference.

II. The EPCO, Inc procedure EGS E-6320, Tank Inspection Repair, has been archived. Enterprise utilizes STD.9503, Inspection and Testing of Atmospheric and Low-Pressure DOT Breakout Tanks, see attached STD.9503 which establishes the correct external inspection methodology consistent with API 653 incorporated by reference.

III. At the time of the April 2011 inspection, Enterprise was using RBI for ultrasonic thickness inspection intervals as allowed in the incorporated version of API 653 in 6.4.3 "......After an effective RBI assessment is conducted, the results can be used to establish a tank inspection strategy and better define the most appropriate inspection methods, appropriate frequency for **internal**, **external** and **on-stream** inspections......"

STD.9503 was revised to remove any reference of RBI for ultrasonic inspection intervals. STD.9503 currently states when the corrosion rate is not known, the maximum interval shall be 5 years, and when the corrosion rate is known, the maximum interval shall be the smaller of RCA/2N years or 15 years. Please see the attached STD.9503 for reference.

Following the adjustment from RBI to the smaller of RCA/2N years or 15 years, no ultrasonic inspection intervals exceed their adjusted interval; please refer to the attachment entitled Inspection Frequency Summary for reference and the attached API 653 inspection reports.

IV. At the time of the April 2011 inspection, Enterprise was using RBI for ultrasonic thickness inspection intervals as allowed in the incorporated version of API 653 in 6.4.3 "......After an effective RBI assessment is conducted, the results can be used to establish a tank inspection strategy and better define the most appropriate inspection methods, appropriate frequency for **internal**, **external** and **on-stream** inspections......."

Attached is a referenced API 653 inspection report that demonstrates the corrosion rate calculations for the bottoms, and the inspection methods utilized, which illustrate compliance with section 6.4.3 of the version of API 653 incorporated by reference.

The attached documentation supports that inspection intervals were established in accordance to API 653 standards at the time of the inspection. Enterprise was and continues to be in compliance with the requirements of 195.432 Inspection of in-service breakout tanks for internal inspection intervals.

**Item #3 - 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 must Inspect the physical integrity of in-service atmospheric and low pressure steel aboveground breakout tanks according to API Standard 653 (incorporated by reference, see § 195.3). 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.**

*Enterprise did not make the repairs recommended by the API 653 inspections or did not have adequate documentation to show that the Operator evaluated the recommended repairs and made a determination that the repairs were not needed. For example, notes* *taken during the inspection from the review of an API 653 inspection report for tank 1007 at the Enterprise East Cushing, OK terminal indicated that there were cracks in the ringwall that needed to be addressed by the Operator. Photographs of the ringwall taken during the PHMSA field inspection showed that the cracks had not been repaired. No documentation was found in the Operator's records indicating the ringwall repair recommendations had been evaluated and that a decision made and justified that repairs were not required. Another similar example of unrepaired ringwall cracks was found for tank 1008 during the field inspection. Examples of additional significant inspection findings can be found in the API 653 inspection reports for tank 1008 dated August 2, 2001 and tank 1009 dated March 6, 2000. Documentation for repair of each of the findings or justification why the repairs were not made was not found in the Enterprise breakout tank files. The field inspection could not verify that all of the repairs were made. The Enterprise breakout tank records must address the API 653 inspection significant findings and document the repairs or provide justification why the repairs were not needed to ensure the safety of the tank.*

Enterprise response to Item #3:

Repairs to the ringwall deficiencies identified in the API 653 inspection report were made to tanks 1007 and 1008 in June, 2011 and associated documentation for these repairs is attached for reference. The significant findings identified in the API 653 report for tanks 1008 and 1009 were repaired in 2001. The most recent API 653 internal inspection for tank 1008 is attached and provides evidence that these deficiencies have been corrected. Repair documentation for tank 1009 is also attached for reference. Repairs for the significant findings were promptly made after their discovery in 2000 as indicated in the attached documentation.

**Item #4 - 195.505 Qualification Program.**

**Each operator shall have and follow a written qualification program. The program shall Include provisions to:**
**(a) Identify covered tasks;**
**(b) Ensure through evaluation that individuals performing covered tasks are qualified;**
**(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;**
**(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined in Part 195;**
**(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;**
**(t) Communicate changes that affect covered tasks to individuals performing those covered tasks; and**
**(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.**

**(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and**
**(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.**

*During a Protocol 9 Operator Qualification inspection an Operator employee was asked to perform a routine monthly breakout tank inspection and the technician did not use the prescribed inspection checklist during the inspection, had difficulty in recalling specific items to be checked, difficulty in explaining the basis for determining when an issue should be documented, and difficulty recalling the specific Abnormal Operating Conditions identified by the operator for the task.*

Enterprise response to Item #4:

To ensure that individuals qualified to Covered Task 27.1, Routine Monthly Inspection of Breakout Tanks, are knowledgeable in the inspection requirements, Enterprise Products has developed a Computer Based Training (CBT), Periodic/Monthly Inspection Checklist. The CBT reflects the requirements established in Enterprise standard STD.9503 "Inspection and Testing of Atmospheric and Low-Pressure DOT Breakout Tanks". All Cushing area operating personnel currently qualified to Covered Task 27.1, Routine Monthly Inspection of Breakout Tanks, will be required to complete the CBT as remedial training and qualification by July 31, 2012.

Enterprise appreciates the opportunity to work with PHMSA regarding the safe operation of our pipelines.

Sincerely,

Kevin Bodenhamer
Senior Vice President, EHS&T

Attachments