NOTICE OF PROBABLE VIOLATION
and
PROPOSED CIVIL PENALTY

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

October 14, 2015

Mr. Graham Bacon
Group Senior VP, Operations & EHS&T
Enterprise Crude Pipeline, LLC
1100 Louisiana Street
Houston, TX 77002

CPF 4-2015-5023

Dear Graham Bacon:

On multiple occasions between August 2013 and May 23, 2014, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code were onsite and inspected the Enterprise Crude Pipeline (EP Crude) system located in New Mexico, Oklahoma, and Texas.

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 violations are:

1. §195.430 Firefighting equipment.
Each operator shall maintain adequate firefighting equipment at each pump station and breakout tank area. The equipment must be-
(c) Located so that it is easily accessible during a fire.

EP Crude failed to have firefighting equipment located so that it is easily accessible at Wildfire Station #2. The station did not have fire protection equipment (fire extinguisher) within the pump station fence perimeter. There was a fire extinguisher at the truck offloading area outside the fenced enclosure.

The EP Crude Procedure 1306 Fire Fighting Equipment states

> *"Fire fighting equipment will be located at each pump station and breakout tank area for Company operated pipeline systems…*
> *The fire fighting equipment must be in proper operating condition at all times, plainly marked as to its identity and the types of fires it is suited for. The equipment shall be located so that it is easily accessible in the event of a fire."*

After the inspection, EP Crude remediated the situation by installing an additional fire extinguisher located in the proximity of the booster pump and the GASO pump.

2. §195.432 Inspection of in-service breakout tanks.

(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).

EP Crude failed to inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks by performing the routine monthly inspection as required by EP Crude Standard.9503 and API 653.

EP Crude Standard.9503 Inspection and Testing of Atmospheric and Low-Pressure DOT Breakout Tanks sections 7.1 and 8.1 state,

> *"**7.1 Periodic Monthly Inspections***
> *Otherwise known as the "Monthly Visual Inspection" by industry, the external condition of the tank shall be monitored by close visual inspection from the ground on a routine basis. This routine periodic in-service inspection shall include a visual inspection of the tank's exterior surfaces. The periodic Monthly visual inspection is intended for monitoring the external AST condition and its containment structure. The periodic Monthly visual inspection does **NOT** require a certified inspector.*
>
> ***8.1 Periodic Monthly Inspections***
> *The interval of such inspections shall be consistent with conditions at the particular site, but shall not exceed one month. The inspection checklist form is utilized in Appendix A, for periodic Monthly visual inspections."*

API 653 Tank Inspection, Repair, Alteration, and Reconstruction section 6.3.1.1 states,

> *"**6.3.1 Routine In-Service Inspections***
>
> ***6.3.1.1** The external condition of the tank shall be monitored by close visual inspection from the ground on a routine basis. This inspection may be done by owner/operator personnel, and can be done by other than authorized inspectors as defined in 3.5. Personnel performing this inspection should be knowledgeable of the storage facility operations, the tank, and the characteristics of the product stored.*
>
> ***6.3.1.2** The interval of such inspections shall be consistent with conditions at the particular site, but shall not exceed one month.*
>
> ***6.3.1.3** This routine in-service inspection shall include a visual inspection of the tank's exterior surfaces. Evidence of leaks; shell distortions; signs of settlement; corrosion; and condition of the foundation, paint coatings, insulation systems, and appurtenances should be documented for follow-up action by an authorized inspector."*

EP Crude failed to perform the December 2013 monthly In-Service Breakout Tank inspections for Tanks #5610, #5611, #5617, #5618, #5650, #5653, & #5654.

3. §195.432 Inspection of in-service breakout tanks.

(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).

EP Crude failed to inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks by performing the external inspection as required by EP Crude Standard.9503 and API 653.

EP Crude Standard.9503 Inspection and Testing of Atmospheric and Low-Pressure DOT Breakout Tanks sections 7.2 and 8.2 state,

> *"**7.2. External Inspection***
> *All tanks shall be given a visual external inspection by an authorized inspector. Insulated tanks need to have insulation removed only to the extent necessary to determine the condition of the exterior wall of the tank or the roof. Tanks may be in operation during this inspection. Documented external inspections are performed by an authorized API 653 inspector only.*
>
> ***8.2. External Inspection Frequency***

The external inspection and must be conducted at least every five 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. Tanks may be in operation during this inspection…"

API 653 Tank Inspection, Repair, Alteration, and Reconstruction section 6.3.1.1 states,

*"**6.3.2 External Inspection***

***6.3.2.1** All tanks shall be given a visual external inspection by an authorized inspector. This inspection shall be called the external inspection and must 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. Tanks may be in operation during this inspection."*

During the Headquarters office review of tank records, PHMSA Inspectors reviewed External Inspection records for several breakout tanks. It was noted that the inspections for Tank 1009 dated 5/10-11/2005 and 4/5/2012, had exceeded the 5 year interval required by API 653 sections 6.3.2.1.

4. §195.432 Inspection of in-service breakout tanks.

(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).

EP Crude failed to inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks by performing the ultrasonic thickness inspection as required by EP Crude Standard.9503 and API 653.

EP Crude Standard.9503 Inspection and Testing of Atmospheric and Low-Pressure DOT Breakout Tanks sections 7.3 and 8.3 state,

*"**7.3. Ultrasonic (UT) Thickness Inspection***
External, ultrasonic thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell…

8.3. Ultrasonic Thickness Inspection Frequency – UT
When used, the ultrasonic thickness measurements shall be made at intervals not to exceed the following.

*(1) When the corrosion rate is **not known**, the maximum interval shall be five years. Corrosion rates may be estimated from tanks in similar service based on thickness measurements taken at an interval not exceeding five years. For additional details, contact the Enterprise Tank Integrity Supervisor.*
*(2) 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."*

*"**6.3.3 Ultrasonic Thickness Inspection***

***6.3.3.1** External, ultrasonic thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell. The extent of such measurements shall be determined by the owner/operator.*

***6.3.3.2** When used, the ultrasonic thickness measurements shall be made at intervals not to exceed the following:*

a. 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.

b. 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."

During the Headquarters office review of tank records, PHMSA Inspectors reviewed Ultrasonic Thickness inspection records for several breakout tanks. It was noted that the inspections for Tank 1009 dated 5/10-11/2005 and 4/5/2012, had exceeded the 5 year interval required by API 653 sections 6.3.3.2. The corrosion rate for the tank was unknown.

5. §195.452 Pipeline integrity management in high consequence areas.
(g) What is an information analysis? In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:
(2) Data gathered through the integrity assessment required under this section;

EP Crude did not to include the threat of SCC on Line S1 into the Information Analysis performed on February 28, 2011. Thus, EP Crude failed to analyze all available information about the integrity of Line S1 and the consequences of a failure prior to the ILI run completed on September 19, 2014.

The EP Crude Procedure IMP-SEC6-01 Information Analysis - Line Pipe, section 2.1.10.8 states,

> *"Indicate if tests for the presence of SCC have been performed on the segment. If tested, identify the number of SCC indications that were found."*

On March 15, 2009, an MFL inline inspection (ILI) tool was run on the Line S1 pipeline segment - 30" Jones Creek to Cedar. Following the ILI run, Integrity Dig #5 was performed on April 13, 2010 for 15 corrosion anomalies. SCC was discovered during the integrity dig and investigation. The SCC was not one of the 15 anomalies called by the ILI run. The investigation determined the SCC was not 'Signification SCC' as defined in NACE SP 0204-2008 *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*. Significant SCC is defined as,

> *"An SCC cluster was defined to be "significant" by the Canadian Energy Pipeline Association (CEPA) in 1997 provided that the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS. CEPA also defines the interaction criteria. The presence of extensive and "significant" SCC typically triggers an SCC mitigation program (see discussion under Post-Assessment Step), but a crack that is labeled "significant" is not necessarily an immediate threat to the integrity of the pipeline."*

The EP Crude Pipeline Integrity Program Std. 9009 *Stress Corrosion Cracking Definition*, section 2.0 Definitions, states,

> *"(3)* ***Insignificant SCC*** - SCC which is neither *Significant SCC* nor is associated with dents, gouges, etc.
> *(9)* ***Significant SCC*** - *axially or circumferentially oriented SCC (which is not associated with dents, gouges, or other geometrical pipeline features) where the SCC depth is greater than 50% WT, or the SCC depth is greater than 10% WT and has an interacting length greater than or equal to 75% of the critical length of a 50% through wall flaw that would fail at a stress level of 110% SMYS."*

In February 2014 during the PHMSA inspection, it was discovered that the Information Analysis performed on the pipeline segment on February 8, 2011 omitted the presence of the SCC on Line S1. EP Crude informed PHMSA, the SCC had been left out of the Information Analysis and Risk Algorithm by mistake. EP Crude planned to perform a new Information Analysis prior to the scheduled 2014 ILI run. The ILI was scheduled for March 15, 2014, but due to construction activities associated with the Seaway Loop Project in close proximity to Line S1, a deviation was filed and the ILI run was rescheduled for July 25, 2014. EP Crude completed the Information Analysis on June 27, 2014 prior to the rescheduled ILI run. The presence of SCC was included in the Information Analysis and Risk Algorithm. Due to several more issues with the rescheduled ILI run, two additional deviations were taken prior to completing the run. EP

Crude stated that due to a time constraint resulting from the 3 deviations, the ILI run was performed using an MFL tool and a Deformation tool as originally scheduled. The tool selection was not changed to include a crack detection tool due to no availability of said tool.

The Information Analysis recommended that additional data gathering and analysis activities be performed as defined in the SCC process for line pipe which contains non-FBE coating and where NACE insignificant SCC has been identified. Crack detection tool assessments are being performed on AID's 849 and 850 of the Seaway Pipeline to identify long seam cracks due to railroad fatigue. EP Crude will evaluate the results of the upcoming Crack Detection Tool assessments for SCC. EP Crude will re-inspect the SCC if the evaluation supports SCC re-inspection.

Although three deviations were taken prior to the ILI run, the assessment was completed on September 19, 2014 which was before the 68 month deadline of November 15, 2014.

The failure of EP Crude to include the presence of SCC in the Information Analysis in a timely manner prior to the 2014 ILI run, resulted in the SCC threat exclusion during the tool selection process. Therefore, EP Crude failed to analyze all available information about the integrity of Line S1 and the consequences of a failure prior to the ILI run completed on September 19, 2014.

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $200,000 per violation per day the violation persists up to a maximum of $2,000,000 for a related series of violations. For violations occurring prior to January 4, 2012, the maximum penalty may not exceed $100,000 per violation per day, with a maximum penalty not to exceed $1,000,000 for a related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that you be preliminarily assessed a civil penalty of $57,600 as follows:

Item number	PENALTY
3	$28,800
4	$28,800

Warning Items

With respect to items 1, 2 and 5, 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 items. Failure to do so may result in additional enforcement action.

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. All material submit in response to this enforcement action may be 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 4-2015-5023** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

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