NOTICE OF PROBABLE VIOLATION
and
PROPOSED COMPLIANCE ORDER

<u>CERTIFIED MAIL - RETURN RECEIPT REQUESTED</u>

September 22, 2014

Mr. Todd Denton
President
Phillips 66 Pipeline, LLC
3010 Briarpark Drive
Houston, TX 77042

CPF 4-2014-5023

Dear Mr. Denton:

On multiple occasions between January and May 2014, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code was onsite and inspected portions of Phillips 66 Pipeline LLC (Phillips) pipeline system located in Texas and Louisiana.

As a result of the inspections, 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. **§195.402 Procedural manual for operations, maintenance, and emergencies.**
(a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

Phillips did not follow their written procedures for Annual Tank Inspection. Phillips 's MPR-2810: PI Form - GPL-205 - Instructions Annual Tank Inspection Report, Rev. 4 – Effective Date: 2012-04-02, Section 6 states, 'Complete the GPL-205, Annual Tank Inspection as follows: If a question does not apply to the equipment being inspected, mark through the question. This indicates the question is non-applicable.' The procedure also states, '28. Through manholes or roof hatches on the fixed roof, visually inspect the internal floating roof and primary seal or the secondary seal (if one is in service) for the following:

> 28.1. Is the internal floating roof not resting on the surface of the liquid inside the storage tank?
> 28.2. Is there any liquid accumulated on top of the roof?
> 28.3. Is the seal detached?
> 28.4. Are there holes or tears in the seal fabric?
> 28.5. Are there any defects in the floating roof?
> 28.6. Any issues noted with the IFR to fixed roof bonding cable (bonding cables broken, poorly connected, etc.) or floating roof to shell shunts (non-contacting shunts, etc.)
> NOTE: If the answer to any of the above questions is yes, note corrective actions and date taken.'

The procedure also states, 'Outstanding action items should be tracked through the Company equipment inspection database until the recommendation is completed.'

While reviewing Phillips GPL-205 - Annual Tank Inspection Reports for the tank 80003 in Pecan Grove, the PHMSA inspector noted lines 28 (a) through (f) was completed for internal floating roofs inspection on 10/15/2012 and it was marked "not applicable" on 9/27/2013.

Similarly, tank 11 at the Clifton Ridge Marnie Terminal, the Phillips GPL-205 - Annual Tank Inspection Report, lines 28 (a) through (f) was completed for the internal floating roofs inspection on 10/15/2012 and it was marked "not applicable" during 9/27/2013 inspection.

According to DOT Tank Data sheet provide by Phillips indicated that both tanks listed above have internal floating roof. The inspection records provided by Phillips failed to indicate that an inspection of the internal floating roofs during the calendar year 2013 for the aforementioned tanks, per Phillips' Annual Tank Inspection policy.

2. §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;

Phillips failed to ensure through evaluation that employees were qualified to perform covered tasks on 16 separate occasions. While reviewing records associated with the Form GPL-401: External Inspection Checklist for Terminal and Station Piping; PHMSA observed that Phillips failed to ensure through evaluation that an employee was qualified to perform a covered task. Specifically, task CC2835 - External Inspection of Terminal and Station Piping. A Phillips employee conducted External Inspections for the eight locations on 7/27/2012 and again at the same eight locations on 7/10/2013 in the Lake Charles Pipeline facility.

PHMSA reviewed the qualification records for the individual who performed this covered task on aforementioned dates, and the records indicated this individual's qualification records were not current for this covered task. The individual's qualifications were expired on 11/6/2011 and he was not qualified again, until 1/13/2014. At the time of the inspection, Phillips failed to provide documentation indicating this employee was qualified while performing the covered tasks on 7/27/2012 and on 7/10/2013.

If aforementioned covered task CC2835 was performed by a non-qualified individual, Phillips' Operator Qualification, Active Covered Task List & Span of Control, effective Date: 03/18/2013, Version Number: 12.0 requires a span of control of a one to one. According to the inspection documentations provided by Phillips, a qualified employee was not present to observe or to direct this individual at the work site.

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).

Phillips did not properly consider the bottom side corrosion rate when determining the internal inspection interval in accordance with API Standard 653 (incorporated by reference, see **§** 195.3).

Tank #14 in the Lake Charles Pipeline Facility, Sulphur, Louisiana, was constructed in 1963. It had previously been inspected and API 653 was applied in 1994 for this tank, but documentation was not available that established an internal corrosion rate for the tank bottom. Based upon this lack of information, API 653 processes would consider the corrosion rate as unknown, and the maximum internal inspection interval to be 10 years. This would set the first internal inspection for Tank #14 to occur in 2004.

On May 14, 2004, Phillips performed an internal inspection on tank # 14. The inspection report for tank #14, dated May 14, 2004, indicated that the 'Bottom Plate: The MFE and ultrasonic inspection of the tank bottom identified sixty-six areas of underside corrosion ranging from 0.140" to 0.087" remaining thickness.' And 'Recommend these areas be repaired via (12 inch by 12 inch by 0.250 inch) lap patches in accordance with API 653, Section 9.10.' Phillips made the necessary repair and installed Sherwin Williams Dura Plate Liner in September 2004.

API 653 Section 6.4.2 describes the method for establishing the maximum initial and subsequent inspection intervals for internal inspections. Section 6.4.2 requires the calculation of the internal inspection intervals in accordance with Section 4.4.5 providing the owner and operator of breakout tanks obtained data on the thickness and condition of the tank bottom during an internal inspection. An assumption of effective cathodic protection for the tank bottom side is allowed by API 653, which then sets the soil side corrosion rate of the tank bottom plate to zero (0). However, if historic corrosion has taken place, this is not a sufficiently conservative assumption, and the remaining unrepaired pits should be used to calculate the bottom side corrosion rate as specified in API 653. If bottom side corrosion has occurred, it is not appropriate to assume a zero corrosion rate for the tank plate soil side in the calculation of the future inspection interval. The assumption of zero (0) corrosion growth rate is inconsistent with the application of API 653.

Phillips uses a program to determine the next internal inspection date using the formula from API 653, and inputs from the inspection report. PHMSA noted that Phillips used a corrosion rate of zero for UPr (maximum rate of corrosion on the bottom side of the tank bottom plate) in the inspection interval calculation. This value allowed the re-inspection interval to be set at the maximum interval of 20 years or May 14, 2024. For effective cathodic protection (CP), UPr may be set to zero (0). Since corrosion had occurred on the tank bottom side, it was not appropriate to assume effective CP, or use a corrosion rate of zero (0).

Based upon these observations, Phillips failed to correctly demonstrate that they had established a valid rate of corrosion on the bottom side of tank 14, and did not have sufficient information to assume a corrosion growth rate of zero in calculating its inspection interval**.**

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).**

Phillips failed to inspect the physical integrity of in-service aboveground breakout tank # 39 according to API Standard 653, 3rd edition including addendums through 2008 errata (API 653).

Tank # 39 in the Clifton Ridge Marine Terminal, Lake Charles, Louisiana, was constructed in 1981. According to the documentation, tank # 39 had been inspected and API 653 was applied in 2001. According to §195.432(d), the intervals of inspection with API Standard 653 should have begun no later than May 3, 1999. The preliminary inspection report, from the inspection performed in 2001, for tank #39, dated July 2001, indicated that, 'MFE floor scans. These scans were limited / best effort due to obstructions of roof supports, striker plates, patches, rough coating in some areas, especially near the welds and bulging areas due to shell settlement.' The report also indicated that, "Due to this, plus the wide spread coating failures it is recommended that all coating be removed and the floor be re-examined visually." At the time of PHMSA's inspection, Phillips could not provide a final inspection report and failed to provide the remaining service life calculation for the tank bottom as well as the allowable minimum bottom thickness for tank # 39, based on API 653. As a result, documentation was not available to establish corrosion rates for the tank bottom for the top side or the soil side. Based upon this lack of information, API 653 considers the corrosion rate as unknown, and the maximum internal inspection interval is 10 years making the next internal inspection for Tank # 39 due in 2009.

At the time of PHMSA's 2014 inspection, Phillips had not performed an internal inspection of tank # 39. Phillips provided a completed DOT Tank Data sheet that indicated that Phillips set the re-inspection interval at the maximum interval of 20 years, and the next internal inspection of Tank # 39 due in 2021.

When PHMSA brought this issue to Phillips' attention, Phillips conducted a "similar service assessment" on May 6, 2014, and provided the assessment to PHMSA on May 9, 2014. As a result of this assessment, Phillips extended tank # 39 internal inspection interval to 2021. A review of the Phillips' procedures did not include a "similar service assessment". Phillips provided a 'Draft' procedure for 'P66PL-MI-0310-WD, Atmospheric Storage Tank Program, Revision 5 Effective Date: 2013-xx-xx', which now includes "tanks in similar service". Under the 'Draft' procedures, Section 5.5.3 Internal Inspections – Additional Requirements, item 3 states, "The interval between internal inspections may be determined by either similar service per API 653 or the actual measure corrosion rate."

At the time of July 2001 inspection, Phillips did not have the MRT (Minimum Remaining Thickness) calculations and the inspection documentation did not provide enough data to produce or replicate the MRT calculations. The "similar service assessment" should have taken place in 2001. A full internal API 653 inspection including a MFE floor scan for the control tank #38 was not performed until October of 2006. In addition, while reviewing the "Similar Service Assessment Datasheet", PHMSA noted a six year difference for the Bottom Lining Age and a five year difference for the time in this Service between control tank and candidate tank, which raises the validity of "similar service assessment."

Based upon the documentation and further discussion with Phillips' representatives, it appears that Phillips failed to inspect the physical integrity of breakout tank # 39 according to API 653 by exceeding the 10 year internal inspection maximum interval for tanks having unknown corrosion rates. In the event that such inspections were, in fact, performed, the evidence demonstrates the operator violated §195.404(c)(3) by failing to maintain a record of each inspection and test required by this subpart for at least 2 years or until the next inspection or test is performed, whichever is longer.

5. §195.402 Procedural manual for operations, maintenance, and emergencies.
(a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

Phillips did not follow their written Personnel Knowledge Verification & Emergency Response Training procedure.

P66PL-TSD-0103:Personnel Knowledge Verification & Emergency Response Training, Rev. 7 – Effective Date: 2013-10-28, Section 5.5.3 states, "For any checklist item or area for which an employee is found to be deficient (indicated by marking “Fail" or “No" on the checklist), the supervisor shall indicate corrective actions in the appropriate comment block of the checklist. Corrective actions shall include specific actions to be taken by the employee and a date for completion of the actions. Supervisors shall annotate the checklist once the corrective action has been completed".

While reviewing annual the checklist for field employee records, PHMSA noted that an employee was not qualified to perform the covered task CC2835: External Inspection of Terminal and Station Piping during the calendar years 2012 and 2013 and his supervisor checked “yes” for all required training and qualification have been completed. The employee qualification expired on 11/6/2011 and he was not re-qualified again until 1/13/2014. However, the records provided by Phillips indicated that he performed a covered task CC2835 on 7/27/2012 and 7/10/2013. His supervisor conducted an annual checklist on 7/6/2012 and 6/27/2013, which is just a few days prior to performing the covered task and failed to recognize that his qualification was expired and allowed him to perform the covered task. His supervisor did not mark "Fail" or "No" on the checklist. Instead, his supervisor marked “Yes” for Operator Qualification has been completed and did not indicate corrective action in the appropriate comment box of the checklist.

<u>Proposed Compliance Order</u>

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.

We have reviewed the circumstances and supporting documents involved in this case, and have decided not to propose a civil penalty assessment at this time.

With respect to item(s) 1, 3 and 4 pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Phillips. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

<u>Warning Items</u>

With respect to items 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 this item. 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 you 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 4-2014-5023** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R. M. Seeley
Director, Southwest
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 Phillips 66 Pipeline LLC a Compliance Order incorporating the following remedial requirements to ensure the compliance of Phillips 66 Pipeline LLC with the pipeline safety regulations:

1. In regard to Item Number 1 of the Notice pertaining to Phillips failure to inspect the internal floating roofs for Tanks # 80003 and # 11 during their annual tank inspection in Pecan Grove and Clifton Ridge Marine Terminal. Phillips must follow their written procedures, inspect, and provide documentation to indicate that Tanks #80003 and #11 internal floating roofs are inspected.

2. In regard to Item Number 3 of the Notice pertaining to Phillips failing to consider the bottom side corrosion rate when determining the internal inspection interval in accordance with API Standard 653, Phillips must develop procedures that clearly identify when a corrosion rate of zero can be assumed. Phillips must also develop a procedure that clearly identifies if an historic corrosion has occurred, and establish appropriate corrosion rate from the measured data in accordance with API 653. After developing procedures, Phillips must re-evaluate their tank inspection intervals against the revised procedure to ensure that the internal inspection intervals are calculated in accordance with API 653 and to ensure that inspection occur prior to reaching the minimum plate thickness necessary to ensure tank plate integrity.

3. In regard to Item Number 4 of the Notice pertaining to Phillips failing to inspect the physical integrity of in-service aboveground breakout tank # 39 in Clifton Ridge Marine Terminal, Lake Charles, Louisiana, according to API Standard 653, 3rd edition, including addendums through 2008 errata (API 653), Phillips must conduct an API 653 internal inspection. If Phillips wants to utilize “similar service” to determine the interval between inspections they must develop procedures that clearly identifies when similar service assessment will be performed and how it will be performed. Also, Phillips shall establish the criteria for the similar service assessment, identify the responsible group; and what type of personnel qualifications are needed to perform the similar service assessment.

4. Provide PHMSA with documentation that verifies completion of numbers 1 – 3 above within 30 days following the receipt of the Final Order.

5. It is requested (not mandated) that Phillips 66 Pipeline LLC maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to R. M. Seeley, Director, Southwest Region, Pipeline and Hazardous Materials Safety Administration. It is requested that these costs 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.