NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

May 13, 2014

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

CPF 4-2014-5011

Dear Mr. Denton:

On multiple occasions between April and November 22, 2013, 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 portions of Phillips 66 Pipeline LLC (Phillips) pipeline system located in Texas and Oklahoma.

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 violation(s) 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 atmospheric storage tank level alarm policy. P66PL-TPO-4001: Atmospheric Storage Tank Level Alarm Policy (Rev. 7 – Effective Date: 2012-07-09), Section 7 - Inspection and Testing (Quarterly) states:

> "New systems are designed fail safe and alarm upon electrical failure. Steps should be taken to ensure existing systems perform in the same manner where possible. Level alarming systems shall be visually inspected, have an electronic integrity test performed and be functionally tested each quarter. These functions shall include the following: Point-to-point verification will be completed for safety-related points by the field technician in contact with the Controller for that pipeline as part of the repair or calibration using established maintenance procedures. Document the name of the Controller on the form associated with this procedure. The results of these point-to-point verifications will be retained in accordance with current practice for these calibrations."

While reviewing records associated with the overfill protection on Tanks 1201, 1202, 1501, 2101, 2301, 2302, 2303, 2304 and 2305, PHMSA noted the tanks were last inspected on 7/25/2012 and again on 1/29/2013. Phillips failed to provide documentation showing these devices were inspected during the 4th quarter of 2012.

Phillips, during their 1/29/2013 inspection, failed to document that the company conducted an alarm test for tank 1202. Also, during the third and fourth quarters of 2012 and the first and second quarter of 2013, P66PL failed to document the name of the controller on the level alarm inspection and testing report required by their own procedure.

2. §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 cathodic protection testing procedure. P66PL, MPR 6018:Cathodic Protection Testing, Rev. 9 (Effective Date: 2012-03-27), section 7.3.4.1 states:

> "For the annual structure to soil survey, conduct a minimum of four (4) SSP readings at evenly spaced locations around the perimeter of each aboveground storage tank. The structure-to-soil measurements shall be taken adjacent to the tank ringwall and the hook-up to the tank floor shall be on the chime weld extension, on a lug on the tank shell specifically for SSP readings or on another readily accessible location on the tank."

While reviewing Phillips' 2011, 2012, and 2013 annual cathodic protection survey records associated with the PHMSA jurisdictional breakout tanks # 201 and 202, PHMSA noted that the company conducted only one structure to soil potential reading, instead of the required four readings at evenly spaced locations around the perimeter of tanks. When PHMSA raised the concern, the Phillips corrosion technician stated that Phillips had never taken four readings because these tanks are smaller diameter tanks and thus, it was not required. Upon further review, PHMSA found the aforementioned procedure and brought it to the company's attention. The technician agreed and updated the Phillips records accordingly on June 25, 2013. During the PHMSA field inspection, adequate CP levels were noted.

3. §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 29 separate occasions. During the inspection, the following was identified:

While reviewing records associated with the Overfill Protection equipment on the 17 DOT regulated tanks in Pasadena, TX, PHMSA noted that Phillips failed to ensure through evaluation that an employee was qualified to perform a covered task. Specifically, task BT6023.1: Field Inspection and Testing of Overfill Protection Devices on Aboveground Breakout Tanks/Vessels. A Phillips employee performed the task on April 26, 2013. PHMSA reviewed the qualification records for this individual, and the records indicated his qualification was not current for this covered task. According to Phillips, the individual was a new hire and he was not qualified on covered task BT6023.1 until April 30, 2013.

While reviewing records associated with the Annual Tank Inspections for 11 tanks located in Pasadena, TX, PHMSA noted that Phillips failed to ensure, through evaluation, that an employee was qualified to perform a covered task. Specifically task BT2810 - Annual Visual Inspection of Aboveground Storage Tanks Greater than 10,000 gallons. Phillips employee conducted annual tank inspections on 11 separate days for the aforementioned tanks. PHMSA reviewed the qualification records for this individual, and the records indicated that his qualification records were not current for this covered task. The individual was last qualified on this covered task on January 14, 2010. The Phillips Operator Qualification Covered Task Reevaluation Frequency, BT2810, requires subsequent qualification at intervals of three years. Therefore, this qualification expired on or about January 14, 2013. At the time of the inspection, Phillips failed to provide documentation indicating that an employee was qualified prior to performing a covered task during the period of January 17-28, 2013. This individual was re-qualified on 3/4/2013.

While reviewing records associated with PI Form - Span and Exposed Piping Inspection Reports, PHMSA noted that Phillips failed to ensure through evaluation that two employees were qualified to perform a covered task. Specifically task CC6020 - Inspect Span and Exposed Pipe. Two Phillips employees conducted a Span and Exposed pipe inspection on 2/16/2010. PHMSA reviewed the qualification records for these individuals, and the records indicated their qualification records were not current for this covered task. One individual was not qualified for this task and the other individual was qualified on 4/13/2010.

If the aforementioned covered tasks; BT6023.1, BT2810 and CC6020 are 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 documentation provided by Phillips, a qualified employee was not present to observe or direct these individuals at the work site.

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 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 #1301 was constructed in 1972. 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 the lack of information, API 653 processes would consider the corrosion rate as unknown, and the maximum internal inspection interval to be 10 years. This set the first internal inspection for Tank #1301 to occur in 2004.

On January 16, 2004, Phillips performed an internal inspection on Tank # 1301. The inspection report for Tank #1301, dated January 16, 2004, indicated reporting criteria was set by Phillips at 0.180 inch or less remaining thickness for the tank bottom plates. Three topside corrosion pits (Plat No. 63A, 48A and 48B) and one bottom-side corrosion pit (Plat No.56A) were identified during this inspection (Reference Table A-Bottom Reduction, section 6 of this report). Upon reviewing this table, PHMSA noted, the minimum thickness remaining of 0.180, 0.180, 0.165 and 0.170 inch for plat 63A, 48a, 48B and 56A, respectively. Of these four corrosion pits, Phillips repair documentation showed only two anomalies were repaired and Minimum thickness for tank floor plate, API 653 Section 2.4.7 calculation sheet shows 3 topside and one soil side pitting repaired). Thus two reports are contradicting each other.

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 a zero (0) corrosion 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. There are no accompanying procedures that are used by the Phillips to establish when it is appropriate to assume that cathodic protection (CP) is effective, and the corrosion rate can be effectively ignored in the re-inspection interval calculation. PHMSA noted that Phillips used a corrosion rate of zero for UPr in the inspection interval calculation. This value allowed the re-inspection interval to be set at the maximum interval of 20 years. With UPr set equal to zero (0), Phillips set the next internal inspection date for January 16, 2024. API 653 defines UPr as the maximum rate of corrosion on the bottom side of the tank bottom plate. Instructions state to calculate the corrosion rate, use the minimum remaining thickness after repairs. For effective 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). Using the data obtained from the inspection report, and assuming a linear corrosion rate based upon the age of the tank, PHMSA requested Phillips to input "No" into the program for effective CP and use a value for UPr set equal to actual corrosion growth rate in inches per year. These calculations yielded the next internal inspection date of May 4, 2016, significantly less than 20 years.

Based upon these observations, PHMSA determined that Phillips failed to correctly demonstrate that it had established a valid rate of corrosion on the bottom side of tank 1301, and did not have sufficient information to assume a corrosion growth rate of zero in calculating its inspection interval.

5. §195.452 Pipeline integrity management in high consequence areas

(h) What actions must an operator take to address integrity issues?

(2) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable

Phillips failed to declare discovery of a condition within 180 days despite the availability of the vendor reports to make such determinations.

On October 11, 2009, Phillips ran an NDT UT tool for the WT-80 pipeline between Slaughter and MP 137. Subsequently, Phillips received a preliminary report for this run, which reported four "Company Priority Criteria" features that met the criterion of > 160 mils in depth. Phillips received the final report on April 7, 2010, which was 2 days before the IMP discovery deadline (180 days). Phillips claimed that the vendor's final report submitted on April 7, 2010, did not contain adequate information about the condition of this pipeline to determine if a potential threat to the integrity of the pipeline exists. Phillips took until April 16, 2010, which is 7 days past the IMP discovery deadline to load the final report data for analysis.

While Phillips was reviewing the tool run data in CPL-AID, they noted one anomaly was in an HCA at Station 383050 and was determined to be an IE 3 Priority (Anomaly that is in the judgment of the person designated by the operator to evaluate the assessment result required immediate action. Cracks, SCC, or HIC indications called by an ILI vendor with criteria as follows: (E3) Cracks with a calculated predicted Burst Pressure (Burst) < MAOP at the anomaly location). Phillips did not limit the pressure at this anomaly site to 625 psi or less until 4/28/2010.

Phillips Integrity Management Program, Section 5.4.1: Process for Assessment Results Review states:

> "When results are received in the form of Final Report, the INGRITY ENGINEER evaluates the data and charts according to IEP 2.03 ILI Assessment Procedure within 30 business days from the receipt of report."

A review of IEP 1.03 – Reporting Requirements for Pipeline In-Line Inspection Procedure revealed that Phillips allows 180 days for the Final Report to NDT Global vendor who runs the UT-UC tool. Thus, Phillips procedure provides 180 days plus 30 business days to evaluate the data. The operator's anomalous condition discovery process is inconsistent with the regulatory requirement.

It was Phillips, while analyzing the vendor's data in final report noted a threat to the integrity of the pipeline, but not until 4/28/2010, which was beyond 180 days. A vendor's failure to highlight an immediate repair condition in the Executive Summary or "feature summary listings" does not excuse Phillips' failure to discover the immediate condition within the 180-day timeframe.

6. § 195.452 (b) ***What program and practices must operators use to manage pipeline integrity?*** **Each operator of a pipeline covered by this section must:**
(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

(5) Implement and follow the program.

Phillips failed to make the appropriate changes to and follow their Integrity Management Plan to insure that the manual is effective. Phillips Integrity Management Program, Section 5 Inspection and Repair, Pipeline Maintenance and Leak Report, Section 5.6.3 states:

> "P66PL uses the Pipeline Maintenance and Leak Report (PMLR) located in *e-Forms,* in conjunction with the *ILI Integrity Work List,* to track the completion of repairs. O&M Personnel complete and submit the PMLR, Form 3933, Pipeline Maintenance & Leak Report (PMLR) and companion Form 3933B, Field Anomaly Evaluation for any of the following tasks, and distribute them as detailed in MPR-2809, Instructions for Completing Form 3933 –

Pipeline Maintenance & Leak Report (PMLR), and MPR-2839, Instructions for Completing Form 3933B Field Anomaly Evaluation:

- Evaluating ILI features

Mapping receives the submitted PMLR, and then follows the workflow described in *IEP 3.04 Pipeline Maintenance & Leak Report (PMLR) – Process Work Flow*. This workflow describes how the new data received is used to update the PODS database and where the hardcopy records are stored."

PHMSA learned that both MPR 2809 and MPR 2839 were discontinued in 2009. According to Phillips, the eForm is a smart form and self-explanatory. Phillips last revised their IM plan (Revision 9) on July 21, 2011.

In addition, while reviewing the 2010 UT Crack Tool Okarche to Clinton data, dated 9/22/10, it was noted that Phillips identified a total of 5 "Company Priority Criteria" conditions, based upon the company criteria HCA & Non-HCA - Anomalous Condition Definition. Of those five, two of the priority conditions (Station 1006239.13 and 1006232.05) were anomalies defined as IE Priority 2005C (Cracks, SCC or HIC indications called by an ILI Vendor with criteria as follows: C) Cracks with a calculated Predicted Burst Pressure (Burst) < MOP at the anomaly location). For these two anomalies, Phillips made a repair with a 12' full encirclement sleeve and completed the Pipeline Maintenance and Leak Report (PMLR)(eForm # LO-01-11-0504). Upon further review of this eForm, PHMSA learned that the "Field Anomaly Evaluation" documentation (eForm 3933B), dated 1/20/2011, reported that the first anomaly was 32.250 feet offset from weld # 96260, and 79.2 inches long, and, the second anomaly was 25.17 feet offset from weld # 96260, and 43.7 inches long. Based on this information, the anomaly should have been repaired with more than twelve (12) feet.

In the same eForm, the "Inline Inspection Tool Correlation NDE Report" dated 1/20/2011 reported that a total axial length of these two anomalous conditions from start to end (start of indication 24.31 and 35.60 end of indication) is 11.29 feet and, as a result, a 13.10 feet length of pipe was examined. But based on this report, 12 feet of type "B" sleeve was installed between upstream station # 10062+63.13 and downstream station # 10062+75.13.

Two separate forms for the same location contradict each other. PHMSA verified Phillips' PODS Database on 11/22/2013. The PODS Database showed 12 feet of full wrap was utilized at this location. It appears that Phillips O&M personnel failed to accurately complete the companion form 3933 B of PMLR during their field anomaly evaluation on 1/20/2011. In addition, the Supervisor, the Integrity Group and Mapping, failed to review the "Anomaly Evaluation"- for thoroughness on 2/14/2011, 2/21/2011 and 4/15/2011, respectively. Phillips failed to correct this issue until PHMSA brought it to the company's attention.

During the inspection, PHMSA noted several maintenance and construction related eForms throughout the SW Region were found incomplete. Phillips completed these forms only after PHMSA brought to the attention of the company.

7. **§195.452 Pipeline integrity management in high consequence areas.**

(f) What are the elements of an integrity management program? An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:
(1) A process for identifying which pipeline segments could affect a high consequence area;

Phillips did not properly identify all segments that could affect an HCA. While reviewing Phillips' *TranMap10*, which manages and communicates information regarding HCA boundaries, PHMSA noted that Line EZ at Hwy 183 crossing in Austin (East side is Creedmoor Street, Area Pilot Knob) appeared to be in an HCA. When PHMSA inquired further, Phillips responded that an older revision of the NPMS (based on 2000 census data) did not identify this area as an HCA. Phillips conducted the first HCA analysis for this area during the 3rd Quarter of 2006 and determined that it was not an HCA area, because it was not identified as an HCA in NPMS. Phillips updated this area as an HCA on August 28, 2013, only after the new version of NPMS (based on 2010 census data) was released in 2012. According to Phillips, since 1995, nothing has changed and the population has not grown. Based on the aforementioned, Phillips relied solely on NPMS data and failed to look for new HCAs on their own. The regulation does not except an operator from meeting the segment identification requirement because data is incomplete and/or is not available on the NPMS. The operator has a responsibility to seek and use alternative data to ensure that it has accurately identified pipeline segments that could affect an HCA.

8. **§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 failed to follow their welding procedures and welder qualification requirements. On September 23, 2009, P66PL ran a NDT UT crack tool on the WT-80 pipeline from Weems to Slaughter, Texas. As a result, one of the anomalies (Station 221227.83) was repaired with a welded sleeve on April 16, 2010. PHMSA reviewed the records associated with this repair (eForm WT-80-10-0517) and identified that one of the two welders used for this project was qualified with ASME Section IX on April 13, 2010. Upon further review of welder qualification record (Form GPL-106) revealed that the actual test value for weld progression (Up/Down) was marked as Downhill. However, the welder was qualified with an Uphill progression.

Phillips' MPR 4401- Welding Procedures and Welder Qualification, Section 11.1.1 states"

> **"**When a qualification weld for THE COMPANY is completed, the inspector or the supervisor shall complete the Welder Qualification Record for that welder and that weld. Refer to MPR-2811 for instructions for completing the Welder Qualification Record, P66 Form GPL-106."

PHMSA reviewed MPR-2811 - Company Forms – Welder Qualification Record (Rev. 1 – Effective Date: 2008-07-08) and learned that the qualified range value for both API 1104 and ASMX IX test, must be the same as the actual test value.

Based on this review, the Phillips Certified Welding Inspector (CWI) failed to follow Phillips' procedures to qualify the welder properly. When PHMSA raised this concern, Phillips stated, "After reviewing Tommy's WQR with our welding SME, he deemed that the paperwork was incorrectly filled out. We've located the CWI (Darryl Ezzell) and reviewed with him the errors found with his paperwork." Phillips CWI updated the same document and resubmitted it (November 15, 2013) with a welding progression actual value as "Uphill."

9. **§ 195.452 (b)** ***What program and practices must operators use to manage pipeline integrity?*** **Each operator of a pipeline covered by this section must:**
(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

(5) Implement and follow the program.

Phillips failed to follow their Integrity Management Program. P66PL-TSD-3008, Evaluation/Repair of External/Internal Pipeline Defects and Anomalies, Rev. 1 – Effective date 2012-10-15, Section 5.1.2: Defect Repair Requirements states:

> "The company will use the repair conditions criteria listed in section 195.452(h) of DOT 195, DOT 192.933, and Appendix A to address anomalies discovered in a High Consequence Area (HCA) and non-High Consequence Area (non-HCA)".

PHMSA reviewed records associated with the WT-80 pipeline TDW Magpie Combo tool run between Slaughter and MP 137 (tool run date 5/12/2010). Philips received the final report on 7/20/10 and discovered two anomalies on 9/27/2010 (repaired in May 2012) and three anomalies on 7/23/2010 (repaired in December 2012) due to the company criteria for non-HCA - anomalous conditions defined per P66PL-TSD-3008. All five anomalies were reported as an IE Priority Code 1030 - Corrosion of or along the Long Seam Weld.

Similarly, PHMSA reviewed records associated with the LO-01 pipeline TDW Magpie MFL tool run between Buxton and Clinton (tool run date 7/6/2009). Phillips received the final report on 10/05/2009 and noted 142 anomalies (discovery date of 10/13/09). Of the 142 anomalies, nine met the company criteria for Non-HCA anomalous condition definitions (1005C: Metal loss where SOP Pressure< MOP at the anomaly location). All nine anomalies were repaired between February – March of 2011. According to P66PL-TSD-3008, Revision 4 - Effective Date: 2012-10-15, repairs are required to be made within 12 months. When PHMSA questioned why the aforementioned anomalies had not been repaired within 12 months, Phillips advised that they combined MPR-4103 General Line and Equipment Maintenance Evaluation/Repair of External/Internal Pipeline Defect and Anomalies (Rev. 13 – Effective Date: 2010-050-13) and GPL 513 into TSD-3008 in 2011. The previous policy (MPR-4103) had an 18-month requirement.

Furthermore, Phillips' Integrity Management Plan, Section 1.3.8: Management of Change states:

> "Over time, changes may occur in the P66PL-operated pipeline systems, the operations of those systems, and/or the environment surrounding those systems, that may influence how an asset could affect an HCA. In an effort to ensure the program remains current, the IMP MOC process ensures proper documentation, communication, and response to changes affecting the program.
>
> The IMP MOC effort focuses on, but is not limited to, the following key areas:
> - Newly identified HCAs
> - Changes to assessment plans
> - Modifications to the IMP based on new information
> - Changes in regulatory requirements
> - Changes in operations
> - Newly acquired integrity inspection data".

While updating the aforementioned policies, Phillips did not follow their IMP MOC procedure by failing to document changes made to assessment plans as described above. Phillips was unable to provide the date this change went into effect.

<u>Proposed Civil Penalty</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. 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 $175,300 as follows:

Item number	PENALTY
2	$45,700
3	$86,400
5	$43,200

Warning Items

With respect to items 1, 8 and 9 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). Failure to do so may result in additional enforcement action.

Proposed Compliance Order

With respect to items 4, 5, 6, and 7 pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Phillips 66 Pipeline LLC. 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. 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 4-2014-5011** 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 4 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 an 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.

2. In regard to Item Number 5 of the Notice pertaining to failure to declare discovery of condition within 180 days, Phillips must amend IEP 1.03 – Reporting Requirements for Pipeline In-Line Inspection Procedure to be consistent with the regulatory requirement of §195.452 (h)(2).

3. In regard to Item Number 6 of the Notice pertaining to Phillips failing to make appropriate changes and follow the Integrity Management Plan, Phillips must amend the Integrity Management Plan, Section 5.6.3 and remove deleted procedures reference.

4. In regard to Item Number 7 of the Notice pertaining to Phillips failing to properly identify an HCA, Phillips must amend the Integrity Management Plan to broaden the HCA identification beyond the sole reliance on the NPMS.

5. Provide PHMSA with documentation that verifies completion of numbers 1 - 4 above within 45 days following the receipt of the Final Order.

6. 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.