Todd Tullio
Manager
Regulatory Compliance

PHILLIPS 66 PIPELINE LLC
3010 Briarpark Drive
P.O. Box 4428
Houston, TX 77042
Phone 832-765-1636

PHILLIPS 66
PIPELINE LLC

June 13, 2014

Rod Seeley Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration
8701 S. Gessner
Suite 1110
Houston, Texas 77074

RE: CPF No. 4-2014-5011

Dear Mr. Seeley:

This letter is in response to the Notice of Proposed Violation, Proposed Civil Penalty and Proposed Compliance Order dated May 13, 2014 (Notice) issued by the U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration (PHMSA) and received by Phillips 66 Pipeline LLC (Phillips 66) on May 15, 2014.

By delivery of this response, Phillips 66 elects to not contest the violations alleged in the Notice but submits the following explanations, information and other materials. It is our positions that these explanations and additional materials will show that Phillips 66 took actions that were in compliance with the regulations and Phillips 66 procedures and policies. We submit that these explanations and materials will warrant mitigation of the civil penalties. With respect to the proposed Compliance Order, Phillips 66 elects to not contest the compliance order and will submit the updated procedures/process once we have received the final order.

By submitting this response, Phillips 66 does not waive any right, privilege or objection that it may have in any separate or subsequent proceeding related in any way to the information provided in the response.

Phillips 66 offers the following response to each of the probable violations and the items listed in the proposed compliance order:

**<u>Probable Violations:</u>**

**Item 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.

***<u>PHMSA Concern:</u>***

*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, Phillips 66 failed to document the name of the controller on the level alarm inspection and testing report required by their own procedure.*

**<u>Phillips 66 Response:</u>**

Phillips 66 has taken efforts to assure that proper documentation will be created and retained at the facility and specifically these devices are inspected and that the inspection reports are properly filed. Phillips 66 will also assure that alarm tests are documented and that level alarm inspection and testing reports are filed and accessible. Further, Phillips 66 has been able to locate some of the missing documentation since the inspection occurred. These records will be placed in the file system at the facility.

**Item 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.

***PHMSA Concern:***

*Phillips did not follow their written cathodic protection testing procedure. Phillips 66, 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."*

**Phillips 66 Response:**

As noted in the comments provided by PHMSA, this issue is an isolated interpretation at a particular location relating to two smaller tanks. This finding is not an indication of a systemic problem but an indication of an interpretation at a certain location. As further indicated by the comments provided by PHMSA, adequate CP levels were noted for these assets and there in no indication that this interpretation caused any elevated concern regarding the integrity of the two tanks in question. Phillips 66 has corrected the item mentioned above. Going forward at this location as well as other locations, our internal Pipeline Compliance System (PCS) will at a minimum require that 4 areas be inspected on all regulated tanks.

Reports through the PCS system can be generated by supervisors to verify that at a minimum all four quadrants of the tanks are being recorded.

PHMSA has proposed a penalty of $45,700 associated with this probable violation. Phillips 66 requests that this penalty amount be reduced for the reasons stated above and the following. It is noted that the issue is not a direct violation of a federal regulation but a question as to whether the Phillips 66 employee properly followed Phillips 66 procedure. Based on the limited scope of the concern and that upon identification of the issue, the issue was addressed, the penalty appears to be excessive and Phillips 66 requests a reduction of the amount.

**Item 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;

***PHMSA Concern:***

*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.*

**Phillips 66 Response:**
Phillips 66 has developed an additional process that will allow supervisors to monitor Operator Qualification's through our Learning Management Systems (LMS). Employees and Supervisors will receive notifications through LMS. Supervisors can generate reports to see when qualifications are set to expire. Employees receive notifications on qualifications set to expire as well through the OQ Management System (OQMS). These notifications go out 90, 60, and 30 days prior to the qualifications expiring. During the time period of the inspection, Phillips 66 had experienced turnover in supervision at this location. Since the time of the inspection, Phillips 66 has placed a high priority to this location in particular, to assure that the operator qualifications are in compliance with federal regulations.

In addition, Phillips 66 is in the process of adding a position to the Operator Qualification group to assist in the administration of the Operator Qualification program and this position will assist in the process of identifying where certifications have lapsed or may be needed for employees of Phillips 66. In addition to this position, Phillips 66 is in the process of identifying additional technological changes in its systems to coordinate notifications to employees and supervisors so that certifications do not lapse for individuals performing such tasks. It is expected that these changes will exceed the penalty amount and Phillips 66 seeks recognition of these efforts through the reduction of the penalty amount of $86,400.

**Item 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).

**PHMSA Concern:**

*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).*

*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. 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.*

**Phillips 66 Response:**

PHMSA states that Phillips 66 failed to consider bottom side corrosion rate when determining the internal inspection interval. Phillips 66 disagrees with this statement. Phillips 66 considered the bottom side corrosion rate on tank 1301 in accordance with API 653. To determine the bottom side corrosion rate, a complete tank bottom scan was performed via Magnetic Flux Evaluation (MFE). The evaluation of the tank bottom identified one soil side condition of .180" remaining wall thickness. The rest of the tank bottom had a remaining thickness that exceeded the .180" remaining wall thickness.

The complete bottom scan showed no evidence of extensive bottom side corrosion anomalies. Therefore the existing cathodic protection system was performing as designed and effective as a corrosion protection system This was further validated by reviewing historical cathodic protection records. The records showed that all readings were well above the required minimums as required by Phillips 66's procedures.

PHMSA states that it determined Phillips 66 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. Phillips 66 disagrees. Per API 653, Section 4.4.5.1, a bottom side corrosion rate of 0 may be used for areas with effective cathodic protection API 653 has AP RP-651 (Cathodic Protection of Aboveground Storage Tanks) as a reference publication as cited in Section 4.4.3.3 – Cathodic Protection. API 651 Section 8 defines adequate cathodic protection, which is synonymous with effective cathodic protection. The cathodic protection on tank 1301 was effective as described above. Using a bottom side corrosion rate of 0 per API 653 Section 4.4.5.1 for tanks with effective cathodic protection in calculating minimum remaining thickness, the 20 year re-inspection interval was shown to be adequate per the API 653 methodology. Although not required per API 653, a .250-inch carbon steel patch plate was installed over the identified area, as an added measure of assurance the minimal required thickness will be achieved at the next inspection interval.

Phillips 66 has procedures in place that clearly identify when a corrosion rate of zero can be assumed. Phillips 66 has demonstrated and can provide further information and data supporting our procedures and policies that clearly identify if a historic corrosion has occurred and establish an appropriate corrosion rate from the measured data in accordance with API 653. The evaluation of our tank inspection intervals are against the procedures which meet the requirements of API 653. Further, our program is designed in compliance with regulations and API 653 so that an inspection occurs prior to reaching the minimum plate thickness necessary to ensure tank plate integrity. If requested or required by a final compliance order, Phillips will provide further explanation to our program in order to highlight how our program satisfies the requirements of API 653 and the federal regulations.

**Item 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

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

**Phillips 66 Response:**
At the time of the UT Crack tool run on WT-80 Slaughter to MP 137 (October 11, 2009), Phillips' reporting requirements stated that final reports were to be received from all vendors within 60 days. PHMSA incorrectly stated that the duration was 180 days. By taking the reporting requirement of 60 days and allowing for the necessary evaluation of up to 30 business day, the time period as set forth in Phillips 66's program was well within the 180 day period as required by the federal regulation. Due to the nature of the crack tool analysis, it was impractical for the vendor to meet this time frame. None of the vendors were able to process reports within this time period. In fact, the vendor's average final report processing time for UT reports in 2010 was 180 days. The vendor delivered this particular report on Day 178.

After any final report is received from the vendor, additional processing time is required to complete the discovery process as outlined in the Integrity Engineer's Procedure (IEP 2.03).

These key steps in the process include: loading the data into our engineering analysis tool (CPL-Aid), which aligns the tool run data with our engineering stationing, MOP values, HCA areas, etc. On the run in question, information was requested from the vendor after the final report was received to correct missing/erroneous data. Upon correction the revised final report was loaded into CPL-Aid on April 16, 2010.

The next step is for an Integrity Engineer to evaluate the CPL-Aid output to determine which anomalies require evaluation. This task was done on April 28, 2010. It was discovered during this analysis that one Immediate condition (IE3) and one Company Priority condition (2005C) existed. The pipeline was derated the same day that these conditions were discovered, April 28, 2010. The final report transmittal and anomaly work list were issued by the Integrity Engineer the following day, April 29, 2010.

There have been several revisions to Phillips 66's reporting requirements (IEP 1.03) since this tool run in 2009. In 2011, the vendor expressed concern about the time it takes to analyze a crack tool run. Based upon these comments, this particular vendor was allowed 180 days to issue the final report. On April 15, 2014, Phillips 66 issued another revision of IEP 1.03 indicating the longest processing time for any vendor is 150 days. This change allows Phillips 66 30 days to complete the discovery process.

As an additional note, all MFL/Caliper tool run data for this pipeline segment were received and processed well within the 180 day discovery requirement. This UT crack tool assessment was not used to reset the 5-year assessment interval; rather it was in addition to and in-between the MFL/Caliper assessments.

The standard as contained in the federal regulation is that 180 day period must be met unless the operator can demonstrate that the 180-day period is impracticable. Impracticability is defined as a fact or circumstance that excuses a party from performing an act because, though possible, it would cause extreme and unreasonable difficulty (Black's Law Dictionary). In this case, the report received on day 178 was not complete and any actions on this report would have been difficult and potentially inaccurate. Further, the condition that was discovered, was first identified by Phillips 66 after receiving the revised information after the 180 day period. This set of circumstances clearly meets the clear and reasonable meaning of the term "impracticable".

Phillips 66 acted in compliance with the regulation by taking prompt action and has demonstrated that in this particular assessment, the 180 day period is impracticable. Phillips 66 requests that this probable violation be withdrawn by PHMSA.

In addition to identifying this issue as a probable violation, PHMSA has proposed a civil penalty of $43,200. As discussed above, Phillips 66 has demonstrated that it did not violate the regulation and so no penalty should be assessed. If it is assumed that Phillips 66 has not demonstrated that 180 day period was impracticable in this particular assessment, the penalty is excessive for the proposed violation. The alleged violation is a failure in the timing of receiving a report from a vendor as it is presumed that the time in which Phillips 66 took actions is reasonable. Further, this is the only identified instance of exceeding the 180 day period for this inspection in which PHMSA reviewed records dating back to 2009. Subsequent changes have been made by Phillips 66 to improve its assessments since 2009. There is no other policy or behavior indicated in the Notice which warrants a penalty and especially a penalty of this amount. Phillips 66 requests that the penalty be withdrawn or in the alternative, significantly reduced.

**Item 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.

***<u>PHMSA Concern:</u>***

*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:*

*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.*

*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.*

**<u>Phillips 66 Response:</u>**

Maintenance Procedures MPR-2809 and MPR-2839 were discontinued on September 27, 2012. The latest version of the Integrity Management Program is dated July 21, 2011. Phillips 66 has been in the process of reviewing its forms, including the e-Forms and has taken corrective action to update such forms and remove unnecessary references and forms. Several revisions, including the removal of these two references, are in progress and will be incorporated and issued in 2014.

**Item 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;

***PHMSA Concern:***

*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.*

**Phillips 66 Response:**

Phillips 66 does not differ with the concept expressed by PHMSA's comments that an operator should seek and use alternative data to ensure that it has accurately identified pipeline segments that could affect an HCA. However, the regulation does not address the concept in this manner but requires a process that identifies which pipeline segments could affect a high consequence area. Phillips 66 disagrees strongly with the statement above whereby PHMSA states that Phillips 66 relied solely on NPMS data. First, a review of the Phillips 66 program will address that NPMS data is used but other sources are required as well. Phillips 66 maintains that the HCA identification process and procedures currently address PHMSA's concern. Phillips 66's Integrity Management Plan Section 2.4 addresses the HCA identification process. Section 2.4.1.1 and Section 2.4.2.1 discuss using NPMS data as our primary data source. However, Sections 2.4.1.2 and 2.4.2.2 require the use of sources and activities beyond the NPMS data. Training on how to identify and report a HCA is available in the form of CBT and is tracked through our online training system, Learning Management Express (LMS). There are also instructions on our TranMap/GIS webpage.

Additionally, Phillips 66 has a SAP Preventative Maintenance task that is sent to all Field Supervisors (~50 Individuals) every September. This process began in 2010 and we have documentation that show this action was completed every year since implementation.

The instructions in the SAP PM order are as follows:

High Consequence Areas (HCA/s)
Reference: 49 CFR 195.452 and 49 CFR 192, Subpart O Mandatory Maintenance Plan for Pipelines Identify previous period (September 1 - August 31) changes that may result in additional High Consequence Areas (HCA/s) pipeline segments.

Right of way changes –

- Areas of population growth
- Utility construction
- Changes in the use of existing buildings
- Increases in the number of one-calls received
- ROW encroachments

Pipeline system changes –

- New Pipelines, Reroutes, and Modifications (e.g., valve installations/conversion)
- Permanent Operational Changes that could affect product dispersion (e.g., service conversions, significant operating pressure changes, product volume/density changes, emergency response capabilities, etc.)

Verify applicable field personnel have reviewed the HCA Identification Training Module within the last 3 years. If no changes are identified, please document review and close.

With regards to this particular location, Phillips 66 followed this process as the process has evolved over the years. Phillips 66 used the NPMS data as a primary data source for its initial determination. However, this particular location is well known to the personnel of Phillips 66 and this location is observed on a regular, if not daily, basis. Through this constant review and monitoring (of non-NPMS data and alternative data), the area was not classified as a HCA. It was not until the new census data and the new NPMS data was released in 2012 that Phillips 66 made the decision to change this to an HCA based on our primary data source determination. We are in the process of verifying with NPMS as to why the determination by NPMS was made which seems to conflict with our alternative data.

Based on our policies in effect when the initial determination was made and the continuing evaluation of this site, there is no violation of the federal regulation as Phillips 66 has a process that identified which pipeline segments could affect a high consequence area and applied this process to this location using NPMS data and alternative data. Phillips 66 requests that this probable violation be withdrawn.

**Item 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.

***PHMSA Concern:***

*Phillips failed to follow their welding procedures and welder qualification requirements. On September 23, 2009, Phillips 66 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."*

**Phillips 66 Response:**

Phillips 66 has a process in place to review these types of documents. An additional review step has been added to the existing process to help insure that all the documentation is accurate. As indicated by PHMSA above, after looking at copious amounts of paper work a couple of errors were found and fixed during the inspection.

**Item 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.

**PHMSA Concern:**

*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>Phillips 66 Response:</u>**
**During the inspection, Phillips 66 was able to provide internal emails that explained the changes that were made on the retirement of MPR-4103 and GPL-513. Both of these documents were combined into TSD-3008. The change in our internal NON-HCA program from 18 months to 12 months was based off comparing what others are doing in the industry and to help drive consistency within the industry.**

**<u>Proposed Compliance Order:</u>**

<u>Item 1:</u> *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 develp 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 API653 and to ensure that inspection occur prior to reaching the minimum plate thickness necessary to ensure tank plate integrity.*

**<u>Phillips 66's Response: In our response to Probable Violation Number 4, we have addressed how our program satisfies the requirements of the federal regulations and API 653. Based upon your review of this information, we request that this Item 1 of the Proposed Compliance Order be withdrawn.</u>**

**Phillips 66 has procedures in place that clearly identify when a corrosion rate of zero can be assumed. Phillips 66 has demonstrated and can provide further information and data supporting our procedures and policies that clearly identify if a historic corrosion has occurred and establish an appropriate corrosion rate from the measured data in accordance with API 653. The evaluation of our tank inspection intervals are against the procedures which meet the requirements of API 653. Further, our program is designed in compliance with regulations and API 653 so**

that an inspection occurs prior to reaching the minimum plate thickness necessary to ensure tank plate integrity. If requested or required by a final compliance order, Phillips will provide further explanation to our program in order to highlight how our program satisfies the requirements of API 653 and the federal regulations

Item 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).*

Phillips 66's Response: One of the conditions of issuing a Compliance Order is a determination that Phillips 66 is engaging in conduct which involves a violation of the federal regulations. With regards to Item Number 5, this is not true. Item Number 5 was a one-time occurrence out of many that were reviewed by PHMSA during the investigation. In this case, the incident took place in late 2009 and early 2010, over four years ago. There are several reviewed after the date of this occurrence and none were identified as a concern. PHMSA has not provided any support to claim that Phillips 66 is currently engaging in this conduct. In fact, PHMSA was provided documentation showing that this had been further addressed by our processes. There is no basis for a compliance order for this item and Phillips 66 request that this item be withdrawn.

*Item 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.*

Phillips 66's Response: By the wording contained in the above referenced compliance item, this is an amendment of the Integrity Management Plan and is not an item that meets the regulatory requirements of a Compliance Order. Certain forms were identified and corrected. However, there is no indication in the information provided in the Notice that Phillips 66 is engaging in conduct in violation of the federal regulations. Phillips 66 requests that this item be withdrawn. If required by Order to provide such amendments, Phillips 66 will provide the documentation that has been previously provided during the inspection.

*Item 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.*

Phillips 66's Response: As previously stated, one of the conditions of issuing a Compliance Order is a determination that Phillips 66 is engaging in conduct which involves a violation of the federal regulations. With regards to Item Number 7, this is not true. Item Number 7 was a determination of a HCA based on certain criteria. There is no indication that there are any other concerns or current conduct that may be considered a violation of federal regulations associated with this item. Phillips 66 maintains that the HCA identification process and procedures currently address PHMSA's concern. Phillips 66's Integrity Management Plan Section 2.4 addresses the HCA identification process. Section 2.4.1.1 and Section 2.4.2.1 discuss using

NPMS data as our primary data source. However, Sections 2.4.1.2 and 2.4.2.2 require the use of sources and activities beyond the NPMS data. If it is assumed that PHMSA's position is correct on the probable violation (which we disagree), it is a single occurrence and based upon the investigation by PHMSA and no other findings, this does not rise to a determination that there is a continuing engagement of conduct in violation of this regulation. Phillips 66 requests that this item be withdrawn from the proposed order.

Phillips 66 requests your further consideration of these matters as addressed in this reply. We request a mitigation of the penalties based on the information provided herein. We request that certain items be either modified or withdrawn from the proposed compliance order. We appreciate this opportunity to provide addition information associated with our position on these matters. Please let me know if you have any questions or comments regarding this matter.

Sincerely,

Todd Tullio
Manager, Regulatory Compliance

CC. Dave Barney/Phillips 66
Van Williams/Phillips 66
Todd Denton/Phillips 66