# NOTICE OF PROBABLE VIOLATION
# PROPOSED CIVIL PENALTY
# and
# PROPOSED COMPLIANCE ORDER

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

June 2, 2016

Mr. David Chalson
Vice President of Operations
Sunoco Pipeline L.P.
4041 Market Street
Aston, PA 19014

**CPF 4-2016-5020**

Dear Mr. Chalson:

From March 24, 2014 to July 1, 2015, 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 inspected your procedures, records and pipeline facilities throughout Texas.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

**1. §195.56 Filing safety-related condition reports.**

**(a) Each report of a safety-related condition under § 195.55(a) must be filed (received by the Administrator) in writing within 5 working days (not including Saturdays, Sundays, or Federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working**

**conditions may be described in a single report if they are closely related. To file a report by facsimile (fax), dial (202) 366-7128.**

Sunoco failed to file safety-related condition reports with PHMSA within five working days after determining conditions existed that met the criteria of a safety-related condition as per 195.55(a)(6).

Beginning on September 20, 2013, Sunoco performed an integrity assessment on their Keller to Corsicana segment using a deformation and magnetic flux leakage (MFL) internal tool. On December 3, 2013, Sunoco discovered nine anomalies in high consequence areas (HCAs), including KLLR-CORS 13-2A, KLLR-CORS 13-3A, KLLR-CORS 13-4A and 13-4B, and documented the anomalies as immediate conditions due to physical damage to the pipeline. On December 4, 2013, Sunoco issued a 20% operating pressure reduction due to the immediate conditions through a Management of Change 6328 on the 16" Ringgold to Corsicana segment. The 20% operating pressure reduction established December 4, 2013 as the date Sunoco determined a safety-related condition existed.

The KLLR-CORS 13-3A, KLLR-CORS 13-4A and 13-4B conditions were repaired on December 18, 2013, which exceeded five working days from December 4, 2013 to the date Sunoco determined safety-related conditions existed. Further, the KLLR-CORS 13-2A condition was repaired on December 19, 2013, which also exceeded five working days after the date of determination of the condition. Accordingly, Sunoco failed to file timely safety-related condition reports in violation of § 195.56. . The following table gives additional details regarding each condition:

| Dig Number | Condition | Date Discovered | Date Determined (Day of 20% Pressure Reduction) | Repair Date | Business Days after Determination /Discovery | 20% Pressure Reduction |
|---|---|---|---|---|---|---|
| KLLR-CORS 13-2A | Top Dent w/ Metal Loss | 12/3/2013 | 12/4/2013 | 12/19/2013 | 11/12 | MOC 6328 |
| KLLR-CORS 13-3A | Top Dent w/ Metal Loss | 12/3/2013 | 12/4/2013 | 12/18/2013 | 10/11 | MOC 6328 |
| KLLR-CORS 13-4A | Top Dent w/ Metal Loss | 12/3/2013 | 12/4/2013 | 12/18/2013 | 10/11 | MOC 6328 |
| KLLR-CORS 13-4B | Top Dent w/ Metal Loss | 12/3/2013 | 12/4/2013 | 12/18/2013 | 10/11 | MOC 6328 |

**2. §195.401 General Requirements.**

**(b) An operator must make repairs on its pipeline system according to the following requirements:**
**(1) *Non Integrity management repairs.* Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.**

Sunoco failed to correct conditions that could adversely affect the safe operation of its pipeline system within a reasonable time. Specifically, Sunoco failed to correct or repair within a reasonable time, several conditions that could adversely affect the safe operation of its breakout tanks as follows:

During the PHMSA field inspection at Sunoco's Colorado City facility in July 2014, Tank 5 was found to have approximately 10 feet of the ring wall foundation severely damaged. The Ring wall had been damaged during the tank's out of service repairs in 2011 and was noted during Sunoco's Tank 5 Out of Service Post Repair report in December 2011. Sunoco, however, did not repair the ring-wall foundation until August 2014, after the PHMSA inspector had inquired about the ring-wall's damage during the field inspection in July 2014. Sunoco failed to correct a condition that could adversely affect the safe operation of its pipeline system within a reasonable time. Two years and seven months was not a reasonable time for repairing the condition of Tank 5.
During the PHMSA field inspections at Sunoco's Ringgold and Corsicana facilities in September 2014, Tank 2703 and Tank 2602, were found to have a half-inch crack on their ringwall foundation. The crack on Tank 2703 had been discovered by Sunoco during the tank's In-Service Inspection in February 2014. Section 3.2.1 of the In-Service Inspection Report for Tank 2703 states, "There was moderate to severe cracking in the concrete. Consider repairing the cracks in the concrete." Sunoco did not repair the crack as per API Standard 653 "Tank Inspection, Repair, Alteration, and Reconstruction", 3rd edition which states 4.5.2.2 Concrete pads, ringwalls, and piers, showing evidence of spalling, structural cracks, or general deterioration, shall be repaired to prevent water from entering the concrete structure and corroding the reinforcing steel. Sunoco did not repair the condition on either tank at a reasonable time. The cracks were repaired on October 25, 2014, after they were noted during the PHMSA field inspections in September 2014. Sunoco failed to correct conditions that could adversely affect the safe operation of its pipeline system within a reasonable time.

**3. §195.402 Procedure 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**

**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.**

Sunoco did not follow their written procedure for tank maintenance. Specifically, Sunoco failed to follow Subpart F, Section 195.432 of their Operations and Maintenance Manual, Inspection of In-Service Breakout Tanks procedure, by not documenting conditions that could affect safe operation of its breakout tanks. Section 195.432, Section 1. I. of the manual, states, "All above ground breakout tanks shall be given a visual inspection on a monthly basis. Results of the visual inspection shall be recorded on form (Sun-42446-A Monthly Aboveground Storage Tank Inspection Report and maintained in the appropriate DOT file" and Section 1. III states "Evidence of leaks; shell distortion; signs of settlement; corrosion; and damage or deterioration of the foundation, paint coatings, insulation systems, and appurtenances or other potential problems shall be documented for review by the facility manager or a designated engineer or authorized inspector." The requisite documentation was not completed in the following instances:

During the PHMSA field inspection at Sunoco's Ringgold facility in September 2014, the PHMSA inspector found a crack on Tank 2703's ringwall. The crack on Tank 2703 had been previously discovered during the tank's In-Service Inspection in February 2014. The Sunoco's monthly inspection reports for Tank 2703 from February 2014 to September 2014 demonstrated Sunoco failed to document the crack on the ring wall. Tank 5 at Sunoco's Colorado City facility, was found to have approximately 10 feet of the ring wall foundation severely damaged and was noted on the tank's post inspection repair report in December 2011. Sunoco's monthly inspection reports for Tank 5 demonstrate personnel failed to document the tank's ring wall damage on their monthly reports from August 2012 to December 2013. The damage was repaired in 2014 after the PHMSA inspector inquired about the damage.

During a PHMSA field inspection at Sunoco's Corsicana facility in September 2014, Tank 2602 was found to have a half-inch crack on the ring wall foundation. Tank 2602 monthly reports from September 2013 to August 2014 where reviewed and Sunoco failed to document any ring wall damage during that time. The crack was repaired in October 2014 after the PHMSA inspector inquired about the damage.

**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).**

**(d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.**

Sunoco failed to perform internal inspections within the maximum interval of 10 years prescribed by API 653, Section 6.4.2.2 which states, "[w]hen corrosion rates are not known and similar service experience is not available to estimate the bottom plate minimum thickness at the next inspection, the internal inspection interval shall not exceed 10 years." and §195.432 for the following breakout tanks:

| Tank | Date Built | Bottom Lining | API 653 Applied by operator | API 653 Internal Inspection Previous | Next API 653 required Internal Inspection Performed by year: | Sunoco's API 653 Internal Inspection Current Schedule | Sunoco's API 653 Internal Inspection Interval |
|---|---|---|---|---|---|---|---|
| **2601** | 1947 | Concrete | 1997 | Unknown* | 2005 | 2017 (scheduled) | >10 |
| **2602** | 1947 | Concrete | 2007 | 5/10/2007 | 2017 | 2027 (scheduled) | >10 |
| **2603** | 1947 | Fiberglass Epoxy | 2000 | Unknown* | 2005 | 2/1/2020 | >10 |
| **44** | 1992 | Thin Film Epoxy | 2012 | 1/1/2012 | 2009 | 2032 (scheduled) | >10 |
| **15** | 1953 | Concrete | 2008 | 2/1/08 | 2018 | 2028 (scheduled) | >10 |
| **17** | 1953 | Concrete | 2007 | 2/1/07 | 2017 | 2027 (scheduled) | >10 |
| **42** | 1953 | Concrete | 1996 | Unknown* | 2005 | 2016 (scheduled) | >10 |
| **2703** | 1954 | UNKNOWN | 1995 | 1/1/1995 | 2005 | 2015 (scheduled) | >10 |
| **2720** | 1956 | EPOXY | 2004 | Unknown* | 2005 | 2025 | >10 |

* NOTE: Out-of-service internal inspection reports were not provided.

Sunoco could not provide the out-of-service internal inspection reports for tanks 2601, 2603, 42, 2720 to confirm an internal inspection had been performed and corrosion rates had been established. If the date of the last inspection cannot be determined based on the available records, an operator should perform an API 653 inspection immediately after acquiring a breakout tank from another operator. Since Sunoco acquired ownership of tanks 2601, 2603 and 2720 on August 1, 2005, and tank 42 on February 17, 2006, and could not determine when the last internal inspections were performed, and the corrosion rates of the tanks are not known, the internal inspection interval should not have exceeded 10 years. The aforementioned internal inspection reports were also asked for by PHMSA during a 2007 inspection and Sunoco was unable to provide them at that time.

Tank 44 was constructed in 1992 and had its first out-of-service internal inspection performed in 2012. Since Tank 44 did not have a corrosion rate established, Sunoco needed to perform an internal inspection on Tank 44 in 2009, 10 years after PHMSA adopted API 653 in 1999. Sunoco failed to perform an internal inspection within the required time frame.

Finally, the type of liner for Tank 2703 is unknown. The last internal inspection of the tank was performed on September 15, 1995 by the previous owner. The 1995 inspection report states there was internal corrosion found on the bottom, but no corrosion rate was established. Sunoco has scheduled the next internal inspection for 2015, an interval of 20 years, even though Sunoco did not know what liner was applied during the tank's repairs. Since the material and thickness of the liner is not known and the corrosion rate is unknown, the inspection interval should have been 10 years and Sunoco needed to perform an internal inspection in 2005. Sunoco failed to perform an internal inspection within the 10 year interval.

**5. §199.202 Alcohol misuse plan.**

**Each operator must maintain and follow a written alcohol misuse plan that conforms to the requirements of this part and DOT Procedures concerning alcohol testing programs. The plan shall contain methods and procedures for compliance with all the requirements of this subpart, including required testing, recordkeeping, reporting, education and training elements.**

Sunoco failed to follow their written alcohol misuse plan by failing to perform a post-accident alcohol test on a covered employee as soon as practicable, after the employee's performance of a covered function contributed to an accident.

On September 24, 2013, at 1:08 p.m., a Sunoco employee was performing a maintenance covered task on a mainline block valve when an accident, reportable under 49 CFR Part 195, occurred. The cause was found to be the employee's failure to follow Sunoco's maintenance procedure which led to a suspension of the employee's OQ qualifications. A post-accident alcohol test was performed on September 25, 2013 at 2:20 p.m., approximately 23 hours after the accident. Sunoco failed to conduct post-accident alcohol testing within 8 hours of an accident employee whose performance of a covered task caused the accident as per their procedure.

Sunoco's Substance Abuse Policy Appendix D Alcohol Misuse Prevention Plan and Procedures (AMPPP), Section II, B, 3. Post-Accident Testing, states a post-accident test will occur as soon as possible but no later than 8 hours following an accident. It also states each employee shall be required to submit to an alcohol test within 2 hours of the accident.

**6. §195.452 Pipeline integrity management in high consequence areas.**

**(l) *What records must* be kept? (1) An operator must maintain for review during an inspection:**

**(i) A written integrity management program in accordance with paragraph (b) of this section.**

**(ii) Documents to support the decisions and analyses, including any modifications, justifications, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.**

Sunoco failed to provide documents to support actions taken to implement and evaluate each element of the integrity management program. Specifically, Sunoco failed to provide the records of the field changes made to the safety related set points when a 20% pressure reduction took place as a result of anomalies identified by ILI runs. During the inspection in May 2014, PHMSA identified four (4) instances where a 20% pressure reduction took place.

As per Sunoco's Management of Change (MOC) procedure, PR-11-0039, 2.1 Facilities or Equipment Affected states 'This procedure is designed to manage permanent or temporary changes to all pipeline and terminal facilities and the operations that affect these facilities. This procedure is intended for changes to the following, but is not limited to: 1. Pipelines and pipeline components; 2. Pump station equipment and pipeline; 3. Instrumentation and Control equipment and program;' and etc.

From Sunoco's MOC procedure, Section 6.0 Examples, a MOC is required for 'Changes to pipeline operating conditions based on Inline Inspection Results'. During the review in May 2014, of the MOC documentation, inspectors requested Sunoco to provide documentation to demonstrate that the field changes to the safety related set points had been documented due to the pressure reductions. Sunoco responded that field documentation was not required as all the field changes were part of Management of Change (MOC) process. A review of the MOC documentation does not indicate that adjustments to devices or safety related set points were made in the field.

The following instances of the Management of Changes due to the pressure reductions are:

a) MOC ID# 5003
Date Created: 12/13/2012; Date Required: 12/13/2012
Location: F-Colo-Colorado City WTG (facility)

b) MOC ID# 6257
Date created: 12/6/2013; date required: 12/6/2013
Location: F-Ring-Ringgold (Facility)

c) MOC ID# 6328
Date created: 12/4/2013; Date required: 12/4/2013
Location: F-Ring- Ringgold Facility

d) MOC ID # 6411

Date created: 12/20/2013; Date required: 12/20/2013
Location: F-Ring-Ringgold Facility

The inspectors also reviewed Sunoco's Operation and Maintenance Manual, Section 195.446: Control Room Management which states:

*"SPLP Requirements / Process description*

1. *Field maintenance technical groups are responsible for ensuring the accuracy of field instrumentation exchanging data with the SCADA systems……… Testing and calibration of each type of instrument will be done in accordance with these schedules and to accuracies as defined within the Eastern area CMMS maintenance Management system……..*

2. *Implement API RP 1165 whenever a SCADA system is added, expanded or replaced, unless it is determined that certain provisions of API RP 1165 are not practical.*

3. *Conduct point to point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays*

4. *Field personnel shall contact the appropriate control room when emergency conditions exist and when making field changes that affect control room operations."*

While in the field, PHMSA requested Sunoco to provide documentation to demonstrate the field changes to the safety related set points had been documented due to the pressure reductions. Sunoco was unable to provide documentation to indicate that this was performed.

**7. §195.579 What must I do to mitigate internal corrosion?**

**(a) General. If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.**

Sunoco does not have procedures for mitigating internal corrosion to identify the potential for internal corrosion at low points, changes in elevation, sharp bends, infrequently used piping, pump stations, and dead legs or assessing, monitoring and mitigating the effects of internal corrosion at those identified locations. Sunoco's procedures that address internal corrosion include: Pipeline Internal Corrosion Control Guideline CORR-TG-0501, Facility Integrity Program OPER-PR-0003, Dead Leg Removals and Line Flushing Procedure OPER-PR-0008.

Sunoco's Facility Integrity Program OPER-PR-003 was developed and implemented in 2011 and was designed to "mitigate facility releases and improve asset reliability and availability." The procedures specifically mention that the purpose of the plan is to assess and learn the general condition of both active and idle piping within the facility. While this manual was put in place to include assessments including internal corrosion, the plan lacks specific and detailed information regarding the actions necessary to performed adequate assessments on the facility piping. The procedure is currently under revision and a draft has been prepared to expand the scope and application of the procedure. The procedure has not, however, been finalized or implemented.

Sunoco's final procedure that addresses internal corrosion in dead legs and low flow pipelines was issued in 2013. Sunoco's Dead Leg Removals and Line Flushing Procedure OPER-PR-0008 was created to determine the extent of lines that would require attention as part of the integrity program based on the operating conditions. The procedure requires identification of dead legs and then actions necessary to manage those identified pipelines. The procedure as written does not include provisions for reevaluation after changes or modifications are made within a station or on the pipelines that could affect their operating conditions.

Sunoco's pipeline system has had several accidents where releases occurred due to internal corrosion, including several in dead legs and low spots in their facilities. Sunoco has experienced eight reportable accidents on terminal piping since 2010 involving internal corrosion.

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $200,000 per violation per day the violation persists up to a maximum of $2,000,000 for a related series of violations. For violations occurring prior to January 4, 2012, the maximum penalty may not exceed $100,000 per violation per day, with a maximum penalty not to exceed $1,000,000 for a related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that you be preliminarily assessed a civil penalty of **$169,200** as follows:

| Item number | PENALTY |
|---|---|
| 1 | $33,700 |
| 2 | $33,500 |
| 3 | $36,700 |
| 4 | $37,800 |
| 6 | $27,500 |

Warning Items

With respect to item 5 we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to promptly correct these item. Failure to do so may result in additional enforcement action.

Proposed Compliance Order

With respect to items 2, 4, 6, and 7 pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Sunoco Pipeline L.P. 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 4-2016-5020** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R. M. Seeley
Director, Southwest Region
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 Sunoco Pipeline L.P., a Compliance Order incorporating the following remedial requirements to ensure the compliance of Sunoco Pipeline L.P. with the pipeline safety regulations:

1. In regard to Item Number 2 of the Notice pertaining to failing to correct or repair conditions found during tank inspections within a reasonable time. Sunoco must define in their procedures a reasonable time frame to repair conditions found during tank inspection, including monthly, external, UT, and internal inspections of tanks.

2. In regard to Item Number 4 of the Notice pertaining to exceeding the internal inspection interval of 10 years, Sunoco must perform internal inspections on its breakout tanks that have exceeded 10 years as required by §195.432 and must also perform internal inspections on tanks 2601, 2603, 42, 2720 as soon as possible or provide the previous actual internal inspection reports to verify internal inspections were performed. Sunoco must also develop and implement a bottom integrity inspection plan for their tanks that have concrete liners and reevaluate the time interval for tanks with unknown corrosion rates. Provide to this office the integrity inspection plan, and a plan and time frame for performing internal inspections as required.

3. In regard to Item Number 6 of the Notice, Sunoco must revise its management of change (MOC) procedures to include actions taken to implement the integrity management program, specifically when a pressure reduction is to take place. MOC procedures must include documentation of field activities taken and their potential impact prior to implementation. The documentation should include the changes made to specific devices and safety-related set points made in the field due to pressure reductions.

3. In regard to Item Number 7 of the Notice, Sunoco must develop procedures to assess the integrity of their facility piping and to include provisions for monitoring and mitigating the effects of internal corrosion in all of their pipelines. Sunoco must perform an assessment to fully determine the corrosive effect of the transported products on their pipeline system to include consideration of low points, changes in elevation, sharp bends, infrequently used pump stations, and dead legs.

4. Pertaining to items above of the Proposed Compliance Order, Sunoco must complete the required documentation within 90 days of the date of the Compliance Order and perform the required internal inspections of the tanks within 180 days of the Compliance Order.

5. It is requested (not mandated) that Sunoco Pipeline L.P., 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.