Sunoco Logistics

Sunoco Pipeline L.P.
One Fluor Daniel Drive
Building A, Level 3
Sugar Land, TX 77478

July 11, 2016

VIA: Electronic Mail and FedEx

Mr. Rod Seeley
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
8701 South Gessner Rd.
Suite 1110
Houston, TX 77074

Re: CPF No. 4-2016-5020
Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order

Dear Mr. Seeley:

The Notice of Probable Violation which includes Proposed Civil Penalties and a Proposed Compliance Order (NOPV) referenced above and dated June 2, 2016 was received by Sunoco Pipeline L.P. (SPLP) on June 6, 2016. This NOPV provided SPLP 30 days to respond. On June 9, 2016 SPLP requested an extension of time to respond. PHMSA granted an extension until July 11, 2016 to respond. Attached to this letter is the SPLP response.

Should you have any questions or require further information, please contact Todd Nardozzi of our Sugar Land, TX office at 281-637-6576 or via email at tgnardozzi@sunocologistics.com

Sincerely,

David R. Chalson
Sr. VP - Operations
Sunoco Pipeline L.P.

Attachments

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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 days after the day a representative of the operator discovers the condition. Separate 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

<u>Proposed Civil Penalty - $33,700</u>

<u>SPLP Response</u>

SPLP does not contest the finding of Probable Violation of §195.56 and will submit payment for the full Civil Penalty in the amount of $33,700.

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 ringwall 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.

Proposed Civil Penalty $33,500

Proposed Compliance Order

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.

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SPLP Response

SPLP acknowledges that the damage to the concrete ringwall(s) was not addressed at the time of the inspection in July and September 2014 respectively. However, SPLP contends that the damages to the ringwalls noted by PHMSA were superficial in nature and that the time until repair did not pose any significant or adverse risk to the safe operation of its pipeline system.

At the time of the 2011 post-repair inspection of Tank 5, the damage to the tank's ringwall did not pose a concern to the structural integrity or the safe operation of the tank. A review of the tank settlement measurements from inspection reports conducted on Tank 5 in 2006 and again in 2011 indicated that there was no evidence of active settlement and that the deflection and settlement readings were within API allowable limits. The shell settlement survey was again confirmed as having no unacceptable settlement or deflection during the January 2016 inspection report.

With respect to the ringwall cracks observed on Tanks 2703 at Ringgold and 2602 at Corsicana, again the cracks in the ringwalls did not pose a concern to the structural integrity or safe operation of the tanks. In general, surface cracks on concrete ringwalls do not pose a serious threat to the stability of a tank unless enough of a ringwall section is missing, so as to create a large enough area where the downward forces of the tank shell can cause a significant out-of-plane deflection.

Although the API 653 In-Service Inspection Report for Tank 2703 noted a crack in the ringwall, the condition was noted to be for "consideration" for repair and the crack, not as a compliance deficiency. As described above, consideration was given to the nature of crack and it was determined that it did not pose a serious threat to the stability or the continued safe operation of the tank.

As PHMSA notes in the Probable Violation report, SPLP took steps to remediate the conditions to the ringwall of each tank noted and provided documentation of such to PHMSA subsequent to the repairs while the inspection was ongoing. Within a reasonable time is a subjective and discretionary. As discussed above, SPLP internal subject-matter experts at no time concluded that the ringwall damage posed any significant or adverse risk to the safe operation of the pipeline system.

Given that the noted nonstructural damages to the ringwalls were repaired it appears that the term "reasonable", with respect to timing of repair is the primary issue in need of resolution. SPLP believes this matter is best resolved by Notice of Amendment to clarify the procedure accordingly. SPLP respectfully requests that the Probable Violation of §195.401 and the associated Proposed Compliance Order be withdrawn as well as the associated Proposed Civil Penalty in the amount of $33,500.

SPLP agrees that its DOT Maintenance Manual Procedure 195.432 should define the term "reasonable" with respect to timing of repair to conditions found during tank inspection, including monthly, external, UT, and internal inspections. SPLP will undertake a review of the SPLP DOT Maintenance Manual procedure 195.432 in conjunction with that which is required by Item 1 of CPF 4-2016-5021M (Notice of Amendment) and define reasonable time frames to repair conditions found during tank inspection.

Given that this item will be completed in conjunction with Item 1 of CPF 4-2016-5021M, SPLP requests to submit the revised procedure 195.432 to PHMSA not later than December 2, 2016 to coincide with the timing committed to by SPLP with respect to the NOA.

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 ln-Service Breakout Tanks procedure, by not documenting conditions that could affect safe operation of its breakout tanks. Section 195.432, Section 1. L of the manual, states, "All aboveground 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.

Proposed Civil Penalty - $36,700

SPLP Response

SPLP does not contest this finding of violation but contends that the penalty assigned was at least higher than warranted evaluating it on its own and by comparison to, for example, Violation #2 herein. Steps will be taken to ensure that all evidence of damage or deterioration of the foundation is noted on form SUN-42446-A ‘Monthly Tank Inspection Report’ and that if the deficiency is determined to be serious or continues to occur after attempts have been made to correct the deficiency by the next inspection, notification shall be made to the appropriate District Engineer to investigate and prescribe the proper course of action to be taken.

Section 190.255 provides that PHMSA "shall consider: (1) The nature, circumstances and gravity of the violation, including adverse impact on the environment; (2) The degree of the respondent's culpability; (3) The respondent's history of prior offenses; [and (4)] Any good faith by the respondent in attempting to achieve compliance," among other factors. SPLP contends that the Proposed Civil Penalty does not appropriately reflect assessment considerations. First, as compared to Violation No. 2 of this NOPV (which concerned allegedly failing to correct conditions that could adversely affect the safe operation of the pipeline and assigning a penalty of $33,500), assigning a larger Proposed Civil Penalty for this Violation No. 3 of $36,700 and is disproportionate. Secondly, there were no injuries or fatalities, no explosion(s), no wildlife impact, and no water contamination and, accordingly, no impact on health and little (if any) impact on the environment, which was short term and promptly remediated. Therefore, the nature, circumstances, and gravity of any alleged violation were comparatively minor under a §190.225 analysis and should be reduced.

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	1/1/95	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.

Proposed Civil Penalty - $37,800

Proposed Compliance Order

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.

SPLP Response

SPLP does not contest the Probable Violation of 195.432 but contends that a penalty reduction is warranted. SPLP has located the prior internal inspection reports for Tanks 2720 (January 14, 2005) and 42 (December 14, 1995). Both reports are included with this response under **Attachment 1**. Accordingly, such reports in fact exist but simply were not readily available for review at the time of the inspection and, as such, the Proposed Civil Penalty attributed to those tanks should be reduced accordingly.

The next OOS inspection date for Ringgold Tank 2720 was calculated to be 20 years from the date of the last OOS inspection that occurred on Jan. 14, 2005 when a new bottom was installed. The 2005 inspection report established a corrosion rate based on the loss of metal that occurred on the old bottom between the year of construction in 1994 and the year of the inspection in 2005. The inspection company used the measured corrosion rate data to establish a 20 year OOS inspection interval for the new bottom. It should also be noted that the 20-year OOS inspection interval was based on a very conservative approach since the new bottom has a corrosion allowance of 25% over the thickness of the old bottom (0.312" vs 0.250"). Typically, in this case, the corrosion rate of the new bottom would be less than the corrosion rate of the old bottom anyway, simply because of improved repair techniques and the use of better materials.

Currently, the repair records for Tank 42 associated with the December 14, 1995 internal inspection are being evaluated by SPLP to validate the internal inspection interval of 20 years. Additionally, records are being researched to validate the inspection intervals of Tanks 2601, 2602, 2603, 15 and 17. Should SPLP locate appropriate inspection and repair records, justification for the current inspection intervals will be supplied to PHMSA by September 4, 2016 (90 days from date of Compliance Order). Should records not be located or if located records do not support the current inspection interval, SPLP will supply PHMSA a schedule for removing the corresponding tanks from service and performance of internal 653 inspections.

For the tanks that have a concrete liner over an existing steel bottom, SPLP developed an integrity inspection plan that is documented in Section 195.432 (3)(VII) of the SPLP DOT 195 Maintenance Manual. Since structural conditions prevent access to the steel bottom under the concrete liner, SPLP has developed the inspection plan to ensure that concrete liners are either properly repaired, or if repair is not feasible, the concrete liner is removed in favor of a new steel bottom. A copy of this procedure has been included in this response under **Attachment 2**.

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.

Warning Item

SPLP Response

SPLP will ensure that our Substance Abuse Policy is followed and in the future post-accident testing will occur according to the guidelines specified in the Policy and in compliance with 49 CFR 199. Nonetheless, SPLP desires to clarify and reiterate that there was no suspicion by Company Supervisory personnel at any time that the employee associated with the accident was in any way under the influence of alcohol or any other substances.

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

> **(I) *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 AP I 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.

Proposed Civil Penalty - $27,500

Proposed Compliance Order

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.

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SPLP Response

SPLP contests the Probable Violation of 195.452. During the course of the 2014 PHMSA inspection it was explained to PHMSA the MOC was indeed the vehicle for pressure reductions taken in response to anomalies discovered via ILI runs. The creation of the MOC in conjunction with the completion of the associated Field and SCADA Action Items serve as the required documentation that field related set points have been changed and that Point-to-Point verification with the field device and the SCADA screen has taken place. Copies of MOC ID No.'s 5003, 6257, 6328 and 6411 were reviewed with PHMSA during the 2014 inspection. Each MOC is generated by an Operations Engineer who determines the set points to the field devices and includes details on these set points in the body of the MOC. Each MOC also contains several Action Items that are assigned to the District Technical Supervisor, the Control Center and a member of the SCADA team. The District Technical Supervisor ensures that the field device set points are changed. The Control Center ensures that SCADA Alarms are reset accordingly and that the particular Operations Manual is revised to show these field device set points and the SCADA team ensures that Point-to-Point verification with the field device and the SCADA screen is completed. As part of the inspection, SPLP recalls that the entirety of the contents of each MOC was reviewed by PHMSA including these Action Items.

Included with this response under **Attachment 3** is another copy of each MOC listed below along with each related Action Item including a copy of the Point to Point Short Form completed by the SCADA team as a part of their associated Action Item. This form is utilized by the SCADA group when Point-to-Point verification is performed on six or less devices.

1. MOC ID# 5003 – Including Action Items 10903, 10904, 10905, 10906 & P2P Short Form
   Date Created: 12/13/2012; Date Required: 12/13/2012
   Location: F-Colo-Colorado City WTG (facility)

2. MOC ID# 6257 – Including Action Items 14817, 14818, 14819, 14820 & P2P Short Form
   Date created: 12/6/2013; date required: 12/6/2013
   Location: F-Ring-Ringgold (Facility)

3. MOC ID# 6328 – Including Action Items 15033, 15034, 15035 & P2P Short Form
   Date created: 12/4/2013; Date required: 12/4/2013
   Location: F-Ring- Ringgold Facility

4. MOC ID # 6411
   SCADA Action Item 15232, 15233, 15234, 15235 & P2P Short Form
   Date created: 12/20/2013; Date required: 12/20/2013
   Location: F-Ring-Ringgold Facility

SPLP affirms that this documentation conforms to procedures and adequately satisfies the record of the field changes made to the safety related set points when these 20% pressure reductions took place as a result of anomalies identified by ILI runs. As such, SPLP respectfully requests that the Probable Violation of §195.452 and the associated Proposed Compliance Order be withdrawn as well as the associated Proposed Civil Penalty in the amount of $27,500.

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 Compliance Order

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.

Operator Response

SPLP OPER-PR-0003 ‘Facility Integrity Program’ (FIP) and the CORR-TG-0501 ‘Pipeline Internal Corrosion Control Guideline’ serve different purposes; the FIP provides guidance for evaluation of internal corrosion inside of facilities and the Pipeline Internal Corrosion Control Guideline provides guidance on the mainline internal corrosion program.

At the time of the inspection, the identified procedures above in addition to OPER-PR-0008 'Dead Leg Removals and Line Flushing Procedure' were in effect. While these procedures may not have explicitly listed such features as changes in elevation, low points, sharp bends, and dead legs these types of features would have been addressed by carrying out the steps of internal corrosion control mitigation identified in each document.

Since the time of the inspection, Revision 1 (January 2015) of the 'Dead Leg Removals and Line Flushing Procedure' has been revised. Specifically, Section 3, bullet 1 was revised to define low spots on the pipeline as a focus point where internal corrosion could be a factor. Changes in elevation typically create low spots and as such elevations changes are addressed. Dead legs were also added as a focus point to be evaluated when developing the internal corrosion control plan for a specific pipeline. Sharp bends were not explicitly defined as a critical factor because sharp bends that create low spots were already defined as an internal corrosion factor. Sharp bends could be a factor if the company shipped products with abrasive content and at high flow rate (erosion corrosion) but at this time there is no such operation in the system and, therefore, it was unnecessary to make such an explicit statement.

In Section 2, the guideline discusses when an evaluation or reevaluation is required. Bullet 4 requires a reevaluation when changes occur to operational parameters of the pipeline such as flow velocity, reduced operation periods and changes to the flow direction. These conditions are monitored by the SPLP Senior Internal Corrosion specialist through communication with the Control Center and field operations.

Section 2, bullet 5 indicates that a reevaluation of the internal corrosion control program is done in conjunction with a pipeline integrity assessment. The data provided by ILI allows defining whether internal corrosion exists and its location. The Internal Corrosion specialist uses this information to evaluate whether internal corrosion metal loss exists in locations where the current internal corrosion control program may not be fully effective and allows for the program to be adjusted to specifically address these locations.

The guideline also addresses various monitoring installations, water traps, weight loss coupons, internal corrosion rate probes (ER Probes) that are used to evaluate the corrosive tendencies of the product shipped.

In mid-2015 the FIP was subject to an extensive review and Revision 1 was published in July 2016.

This revision greatly expanded the volume, instruction and detail of the procedure. Below are bullet point highlights of this revision pertinent to the issues raised by PHMSA above:

- Visual inspection and Assessment of all facility piping and piping components
- Create corrosion monitoring locations (CMLs), line numbers, and circuit numbers, and/or corrosion loops.
- Perform baseline ultrasonic thickness reading (UTs) on all piping segments and components, meter cases, strainers, etc.
- Develop a CML spreadsheet for each facility with the following information
- CML number
- Component type (pipe, valve, PRV, 90, 45, Tee, strainer, filter, etc.)
- Size
- Nominal thickness

- Current thickness reading
- Three (3) columns to identify the inspection method (UT, RT, ANDE) used at this location
- Comment column for noting excessive wall lost and or other indications
- Review each inspection plan with corresponding district personnel
- Review the dead-leg remove & operation dead-leg flushing program

Copies of SPLP OPER-PR-0003 'Facility Integrity Program' (FIP), CORR-TG-0501 'Pipeline Internal Corrosion Control Guideline', and OPER-PR-0008 'Dead Leg Removals and Line Flushing Procedure' are included with this response under **Attachment 4**.

SPLP agrees with the Proposed Compliance Order and will in addition to the revisions of the 'Facility Integrity Program', 'Pipeline Internal Corrosion Control Guideline', 'Dead Leg Removals and Line Flushing Procedure' determine if any other existing procedures should be considered for revision or if any new procedures should be developed to address internal corrosion threats in the pipeline system. Any additional revised procedures or newly developed procedures will be submitted to the PHMSA Southwest Region Director for review by September 4, 2016 (90 days from date of Compliance Order).