Williams
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February 3, 2020

Ms. Mary L. McDaniel, P.E.
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration
8701 S. Gessner Road, Suite 1100
Houston, TX 77074

Re: Williams Oil Gathering, LLC – CPF No. 4-2020-5002M

Dear Ms. McDaniel,

On January 17, 2020 Williams Oil Gathering, LLC (Williams) received the subject Notice of Amendment ("NOA") from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") dated January 13, 2020. The NOA is the result of PHMSA's inspection of Williams procedures for external corrosion control in Houston, Texas from December 10, 2018 to July 11, 2019. This letter serves as Williams' formal response to the NOA.

In accordance with the "Response Options for Pipeline Operators in Enforcement Proceedings" enclosed with the NOA, Williams provides the following response:

Response to Notice of Amendment

Williams has elected to not contest the identified inadequacies in the NOA. As directed, Williams has revised the affected procedures to comply with §195.573. Changes to section 12 are highlighted in the attached procedure and should satisfy §195.401(b) and §195.452(h).

Should you have any questions, please do not hesitate to contact me at (713) 215-2535

Sincerely,

Tyson E. Green
Manager, Pipeline Safety - Transmission

Corrosion Control for Hazardous Liquid Pipelines

07.45.01.02	Revision 00	Effective Date 05/24/2018

Overview & Applicability

This Operating Requirement describes the corrosion control procedures and requirements established by the Company to align with CFR 195. This document contains corrosion related sections including external corrosion, internal corrosion, and atmospheric corrosion.

NOTE: Refer to Appendix A for specific West Virginia requirements.

NOTE: The corrosion control procedures and requirements established by the Company including those for the design, installation, operation and maintenance of cathodic protection systems, must be under the supervision of a person or persons qualified by experience and training in the pipeline corrosion control methods for which they are responsible. These qualifications shall include appropriate education, training (such as that provided by NACE, the National Association of Corrosion Engineers) and directly related work experience, as determined acceptable by the Company.

Link to Applicability.

Key Activities

Description	Frequency	OMS Activity Number[1]	Maximo Activity Number
Atmospheric inspection on all onshore pipelines.	Three Year (Y3), not to exceed 39 months		
Atmospheric inspection on all offshore pipelines.	Annual (Y1), per calendar year, not to exceed 15 months		
Cathodic Protection Testing	Annual (Y1), per calendar year, not to exceed 15 months		
Rectifier Inspection	Bi-Monthly (M2), not to exceed 2 1/2 months		
Critical Bond Inspection	Bi-Monthly (M2), not to exceed 2 1/2 months		
Non Critical Bond Inspection	Annual (Y1), per calendar year, not to exceed 15 months		

Description	Frequency	OMS Activity Number[1]	Maximo Activity Number
Internal Corrosion Monitoring	Semi-Annual (M6), not to exceed 7 1/2 months		
AC Interference Monitoring	Annual (Y1), refer to Step 8.6		

[1] Applicable to Transco, NWP, and Gulfstream.

Qualification References

The Responsible Party will complete the required Qualification and Training Requirements before initiating the applicable tasks in this procedure.

Operator Qualification (OQ) Covered Tasks (CTs)[1,2]	Description
CT007	Operate a Valve
CT008	Measurement of Wall Thickness with Ultrasonic Device
CT213	Joining of Metal Pipe and Components by means other than Welding - Threaded and Flanged Connections
CT214	Joining of Metal Pipe and Components by means other than Welding - Threaded Connections
CT215	Joining of Metal Pipe and Components by means other than Welding- Flanged Connections
CT217	Small Diameter Metal Tubing and Fitting Installation
CT401	Examination of Buried Pipelines When Exposed
CT406	Conduct Test to Determine Cathodic Protection Current Requirements
CT407	Perform Cathodic Protection Survey
CT408	Inspect Cathodic Protection Rectifier
CT409	Inspection of interference bonds
CT410	Clear Shorted Casing
CT411	Inspect/Test to Assure Electrical Isolation is Adequate

Operator Qualification (OQ) Covered Tasks (CTs)[1,2]	Description
CT412	Install CP Leads on Pipeline Using Exothermic Weld
CT413	Anode Installation on Submerged Pipeline or Facilities
CT414	Inspect for Internal Corrosion Whenever Pipe is Removed
CT415	Monitoring for Internal Corrosion with Probes and Coupons
CT416	Monitoring for Internal Corrosion with Gas Samples
CT417	Atmospheric Corrosion Monitoring
CT418	General and Localized Corrosion Measurement (Remedial Measures)
CT419	Cathodic Protection Potential Measurement
CT420	Soil Resistivity
CT421	Measurement of Depth of Pitting with Pit Gauge
CT426	Inspect Pipe Coating with Holiday Detector
CT427	Inspection of Above or Below Ground Coatings
CT428	Pin Brazing to Install CP Leads on Pipeline
CT429	Monitoring for corrosion - bacteria testing - serial dilution method (MIC)
CT430	Installation and Testing of Mechanical Electrical Connections
CT435	Measure and Identify Mechanical Damage on Installed Pipe and Components
CT436	Perform Close Interval Survey
CT437	Perform Hot Spot Survey
CT480	Apply Approved Coating by Hand Application
CT482	Apply Approved Coating by Mechanical Spray and Hand Application Methods
CT 484	Apply Approved Coatings by Wrap Application
CT718	Monitoring for Internal Corrosion with Liquid Samples

[1] OQ CTs only apply to DOT 192 and 195 regulated facilities.

[2] Non-regulated facilities use a combination of technical training and on the job training to ensure employees have the skill sets necessary to perform the tasks.

Electrical Qualification (QE/EQ)	Description
N/A	

REQUIRED TRAINING		
Operations Development Plan (ODP) Skill Block Number[3,4]	Description	Points
N/A		

[3] Must be completed prior to performing the tasks in this procedure.
[4] Applicable to Transco, NWP, and Gulfstream.

Course ID	My Learning Course Description[5]
N/A	

[5] Must be completed prior to performing the tasks in this procedure.

Summary of Responsibilities

Title/Role	Summary of Responsibilities
Asset Integrity Specialist **Asset Integrity Tech Specialist** **Asset Integrity Engineer**	Perform cathodic protection (CP) and corrosion control inspections.
	Perform visual inspections, as needed.
	Perform atmospheric inspections.
	Perform bond inspections.
Asset Integrity Specialist **Asset Integrity Tech Specialist** **Supervisor, Asset Integrity**	Maintain records or maps, as required.
	Maintain record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required, as required.

1.0. External Corrosion Control – Coatings

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
1.1	Make certain that all buried or submerged pipelines have an external coating if the pipeline is:

	• Constructed, relocated, replaced, or otherwise changed after the applicable dates: o An **interstate** pipeline, other than a low stress pipeline, on which construction was begun after March 31, 1970, that transports hazardous liquid. o An interstate **offshore gathering line**, other than a low stress pipeline, on which construction was begun after July 31, 1977, that transports hazardous liquid. o An **intrastate** pipeline, other than a low stress pipeline, on which construction was begun after October 20, 1985, that transports hazardous liquid. o A pipeline on which construction was begun after July 11, 1991, that transports **carbon dioxide**. o A low stress pipeline on which construction was begun after August 10, 1994. • Converted under CFR 195.5, and: o Has an external coating that substantially meets the coating requirements in Step 1.2 before the pipeline is placed in service; or o Is a segment that is relocated, replaced, or substantially altered. **EXCEPTIONS:** • Bottoms of aboveground breakout tanks • The movement of pipe covered by CFR 195.424 CFR 195.557
1.2	Make certain that the coating material for external corrosion control: • Is designed to mitigate corrosion of the buried or submerged pipeline • Has sufficient adhesion to the metal surface to prevent under film migration of moisture • Is sufficiently ductile to resist cracking • Has enough strength to resist damage due to handling and soil stress • Supports any supplemental cathodic protection • If the coating is an insulating type, has low moisture absorption and provides high electrical resistance CFR 195.559
1.3	Inspect all external pipe coating required by Step 1.1 and repair any coating damage discovered prior to lowering the pipe into the ditch or submerging the pipe. CFR 195.561

2.0. Cathodic Protection on Pipelines

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
2.1	Provide cathodic protection for buried or submerged pipeline described in Step 1.1 no later than one year after it is constructed, relocated, replaced, or otherwise changed. CFR 195.563
2.2	Provide cathodic protection for buried or submerged pipeline converted under CFR 195.5 if:

	• The buried or submerged pipeline converted meets the criteria described in Step 6.1 before the pipeline is placed into service; or • A segment that is relocated, replaced, or substantially altered. CFR 195.563
2.3	Cathodically protect all other buried or submerged pipelines that have an effective external coating. Except as provided by Step 2.4, this requirement does not apply to breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003. CFR 195.563
2.4	Cathodically protect bare pipelines, breakout tank areas, and buried pumping station piping in places where regulations in effect before January 28, 2002 required cathodic protection as a result of electrical inspections. CFR 195.563
2.5	Cathodically protect unprotected buried or submerged pipe in areas in which active corrosion is found. CFR 195.563

3.0. Cathodic Protection on Tanks

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
3.1	After October 2, 2000, install cathodic protection in accordance with ANSI/API RP 651 when applying CP to protect the bottom of an aboveground breakout tank of more than 500 barrels 79.49m^3 capacity built to API Spec 12F, API Std 620, API Std 650, or API Std 650s predecessor, Standard 12C, unless certain provisions of ANSI/API RP 651 are not necessary for the safety of the tank. CFR 195.565

4.0. Test Points

Except for offshore pipelines, each buried or submerged pipeline or segment of pipeline under cathodic protection must have electrical test leads for external corrosion control.

CFR 195.567

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
4.1	Install test leads: • Locate test leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection • Provide enough looping or slack to keep the wires connected and electrically conductive after backfilling • Prevent lead attachments from causing stress concentrations on pipe

	• Coat each test lead and any bare metallic area with a coating compatible with the pipeline coating and test lead wire insulation CFR 195.567
4.2	Maintain test lead wires in a condition to obtain electrical measurements. CFR 195.567

5.0. Examining Exposed Pipelines

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
5.1	Whenever a buried pipeline is known to be exposed, examine the exposed portion for evidence of external corrosion if the pipe is bare or the coating is deteriorated. If corrosion is found, refer to 07.45.50.03 – Gas Pipes Pipeline Examination, F-212 – Exposed Pipe and Remedial Action Report, M07-204 – Midstream Maintenance Report, or the appropriate Work Management System being used. CFR 195.569

6.0. Cathodic Protection Criteria

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
6.1	The Company will use one or more of the following cathodic protection criteria: • A negative (cathodic) potential of at least 850 mV with the CP applied. This potential is measured with respect to a saturated copper-copper sulfate reference electrode contacting the electrolyte. Voltage drops other than those across the structure-to-electrolyte boundary must be considered for valid interpretation of this voltage measurement. • A negative polarized potential (i.e., instant off) of at least 850 mV relative to a saturated copper-copper sulfate reference electrode. • A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be measured to satisfy this criterion. • On bare or ineffectively coated pipelines when long-line corrosion activity is of primary concern, the measurement of a net protective current at predetermined current discharge points from the electrolyte to the pipe surface, as measured by an earth current technique, may be sufficient. The decision of which criterion to use will be determined by qualified corrosion control personnel responsible for that pipeline system. CFR 195.571 NACE SP 0169-2007
6.2	When taking readings, consideration for the significance of IR drop will be based on sound engineering principles, such as use of IR free coupons or other means including: • Measuring or calculating the voltage drops

	• Reviewing the historical performance of the CP system • Evaluating the physical and electrical characteristics of the pipe and its environment • Determining whether or not there is physical evidence of corrosion NACE SP 0169-2007
6.3	Once voltage drop is determined, it may be used to correct future measurements at the same location, provided conditions such as pipe and CP system operating conditions, soil characteristics, and external coating quality remain similar. **NOTE:** Placing the reference electrode next to the pipe surface may not be at the pipe-electrolyte interface. A reference electrode placed at an externally coated pipe surface may not significantly reduce soil voltage drop in the measurement if the nearest coating holiday is remote from the reference electrode location. NACE SP 0169-2007
6.4	When it is impractical or considered unnecessary to disconnect all current sources to correct for voltage drops in the structure-to-electrolyte potential measurements, sound engineering practices should be used to ensure that adequate CP has been achieved. NACE SP 0169-2007
6.5	When feasible and practical, inline inspection of pipelines may be helpful in determining the presence or absence of pitting corrosion damage. Absence of external corrosion damage or the halting of its growth may indicate adequate external corrosion control. However, the inline inspection technique may not be capable of detecting all types of external corrosion damage, has limitations in its accuracy, and may report as anomalies items that are not external corrosion. The appropriate use of inline inspection must be carefully considered. NACE SP 0169-2007

7.0. External Corrosion Control Monitoring

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
7.1	Test each pipeline under cathodic protection at least once per calendar year, not to exceed 15 months, to determine if cathodic protection levels meet the criteria from Step 6.1. For separately protected short sections of bare or ineffectively coated pipelines, if the annual testing schedule is impractical, testing may be done at least once every 3 calendar years, not to exceed 39 months. CFR 195.573
7.2	Within two years of cathodic protection installation, identify circumstances in which a close interval survey or comparable technology is practical and determined necessary to: • Assess the effectiveness of the CP system • Provide baseline operating data • Locate areas of inadequate protection levels • Locate areas of possible coating deterioration

	• Identify locations likely to be adversely affected by construction, stray currents, or other environmental conditions • Select areas to be monitored periodically CFR 195.573
7.3	Evaluate unprotected buried or submerged pipe at least once every three calendar years, not to exceed 39 months, to determine areas of active corrosion. Determine the areas of active corrosion by electrical survey. Where an electrical survey is impractical, use other means that include review and analysis of: • Leak repair and inspection records • Corrosion monitoring records • The pipeline environment CFR 195.573
7.4	Install cathodic protection on buried or submerged pipe in areas of active corrosion. CFR 195.573
7.5	Electrically inspect each cathodic protection rectifier or other impressed current power source at least six times each calendar year, not to exceed 2 1/2 months. Rectifiers equipped with remote monitoring systems are polled periodically and submit readings, which meets this requirement. **WARNING**: *Before touching any part of the rectifier case, check for alternating current (AC) fault condition as it may have caused the case to become energized. Taps are energized with AC; do not touch when taking direct current (DC) readings.* CFR 195.573
7.6	Electrically check for proper performance any installed critical bond six times each calendar year, not to exceed 2 1/2 months. Bonds et. al., equipped with remote monitoring systems are polled periodically and submit readings, which meets this requirement. CFR 195.573
7.7	Electrically check non-critical bonds at least once each calendar year, not to exceed 15 months. CFR 195.573
7.8	Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API RP 651. However, the inspection is not required if: • Complying with all or certain operation and maintenance provisions of API RP 651 is not necessary for the safety of the tank, and • This is noted in the corrosion control procedures established under DOT 49 CFR 195.402(c)(3). CFR 195.573

8.0. Electrical Isolation

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:

8.1	Electrically isolate each buried pipeline from other underground metallic structures, including bare facilities at tie-ins, unless the pipeline and the other structures are being cathodically protected as a single unit. CFR 195.575
8.2	Install isolating devices (such as flange kits or insulated fittings) where electrical isolation of a section of a pipeline is necessary to facilitate the application of cathodic protection. CFR 195.575
8.3	Do not install an isolating device in an area where a combustible atmosphere might occur, unless precautions are taken to prevent arcing. CFR 195.575
8.4	Inspect and test isolating devices to ensure that electrical isolation is adequate. CFR 195.575
8.5	Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at isolation devices. CFR 195.575
8.6	Test above ground test stations or equipment for AC voltages annually when: • HVAC interference is suspected • Incidental shock/arc hazard has been reported
8.7	If AC current density is greater than or equal to 30 a/m^2 is found, a qualified person will evaluate the need for mitigation. If the AC potential is greater than or equal to 15 volts, install AC mitigation methods for personnel safety.

9.0. Interference

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
9.1	Frequently monitor (i.e., during annual surveys, bond inspection, etc.) each Company pipeline system, determined to be subject to stray currents, to identify any detrimental effects on the pipeline caused by such currents. A program will be developed to minimize the detrimental effects of the currents. CFR 195.577
9.2	Every cathodic protection system (impressed current or galvanic anode) connected to Company pipelines and facilities must be designed and installed to minimize any adverse effects on any adjacent underground pipelines or other metallic structures. Cooperative interference tests should be made between interfering structures. CFR 195.577

10.0. Internal Corrosion

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:

10.1	If a pipeline transports any hazardous liquid that could corrode the pipeline, investigate the corrosive effect of the hazardous liquid on the pipeline and take adequate steps to mitigate internal corrosion. If corrosion inhibitors are used to mitigate internal corrosion: • Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect • Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion • Check coupons or other monitoring equipment at least twice each calendar year, not to exceed 7 1/2 months CFR 195.579
10.2	Whenever any pipe is removed from a pipeline, the internal surface of the pipe must be examined for evidence of corrosion. If internal corrosion requiring corrective action is found, investigate circumferentially and longitudinally (by visual examination, indirect method, or both) beyond the removed pipe from which the segment was removed to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe. Evaluate any problems found to determine the appropriate corrective action; fill out and retain an exposed pipe report form (F-212 – Exposed Pipe and Remedial Action Report, G07-501 – Gas Pipes Pipeline Inspection and Repair Report, or M07-204 – Midstream Maintenance Report). CFR 195.579
10.3	Any tank bottom lining in an aboveground breakout tank built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), must be installed in accordance with API Recommended Practice 652. However, installation of the lining need not comply with all or certain provisions of API Recommended Practice 652 on any tank for which the application of corrosion control could compromise safety of the tank. CFR 195.579

11.0. Atmospheric Corrosion Requirements

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
11.1	Clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere. **EXCEPTIONS:** Exposed pipelines (not applicable to soil-to-air interfaces or offshore splash zones) need not be protected from atmospheric corrosion where it can be demonstrated by test, investigation, or experience appropriate to the environment that pipeline corrosion will: • Only be a light surface oxide; or • Not affect the safe operation of the pipeline before the next scheduled inspection CFR 195.581

11.2	Evaluate each onshore aboveground pipeline or portion of a pipeline that is exposed to the atmosphere at least once every three years, not to exceed 39 months. CFR 195.583
11.3	Evaluate each offshore pipeline or portion of a pipeline that is exposed to the atmosphere at least once per calendar year, not to exceed 15 months. CFR 195.583
11.4	Particular attention must be given to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water. CFR 195.583
11.5	Where atmospheric corrosion is found, clean, coat, paint, or jacket the equipment with approved materials per 07.47.70.02 – Midstream Atmospheric Corrosion Inspections or 07.47.50.28 – Gas Pipes Atmospheric and Offshore Splash Zone Corrosion Inspections.

12.0. Remedial Measures

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
12.1	Strength Determination: The strength of pipe with general corrosion or localized pitting may be determined following 07.26.01.02 – Remaining Strength Analysis of Metal Loss. CFR 195.587
12.2	Correct any identified deficiency in corrosion control that could adversely affect the safe operation of its pipeline system as soon as practical, but before the next inspection of survey is due.

13.0. Corrosion Control Records

Asset Integrity Specialist, Asset Integrity Tech Specialist, Asset Integrity Engineer:	
13.1	Maintain current records or maps to show the location of: • Cathodically protected pipelines • Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002 • Neighboring structures bonded to cathodic protection systems CFR 195.589
Asset Integrity Specialist, Asset Integrity Tech Specialist, Supervisor, Asset Integrity:	
13.2	Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode. CFR 195.589
13.3	A record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required in sufficient detail to demonstrate the adequacy of

	corrosion control measures or that corrosion requiring control measures does not exist. Company must retain these records for at least 5 years, except: • Exposed pipe inspection reports • Annual surveys • Active corrosion area measurements • Internal coupons or other monitoring equipment • Internal pipe inspection reports The exceptions must be retained for as long as the pipeline remains in service. CFR 195.589

Recordkeeping

NOTE: For more recordkeeping and retention information, refer to the WIMS Forms Matrix or the Records & Information Management (RIM) website.

Record	Record Location *(Retention requirements apply.)*	Retention Period	Distribution Requirements *(Retention does not apply.)*
Atmospheric Corrosion Inspections	Corrosion Database	Life of Facility	Remedial items given to Supervisor, Operations
Cathodic Protection Testing	Corrosion Database	Life of Pipeline In Service	N/A
Rectifier Inspection	Corrosion Database	Minimum 5 years of non-corrosive condition	N/A
Critical Bond Inspection	Corrosion Database	Minimum 5 years of non-corrosive condition	N/A
Non Critical Bond Inspection	Corrosion Database	Minimum 5 years of non-corrosive condition	N/A
Internal Corrosion Monitoring	Corrosion Database	Life of Pipeline In Service	N/A
AC Interference Monitoring	Corrosion Database	Minimum 5 years of non-corrosive condition	N/A

Definitions

NOTE: For a complete list of WIMS terms and definitions, refer to the WIMS Glossary.

Term	Definition
N/A	

WIMS References

- 07.26.01.02 – Remaining Strength Analysis of Metal Loss
- 07.47.70.02 – Midstream Atmospheric Corrosion Inspections
- 07.47.50.28 – Gas Pipes Atmospheric and Offshore Splash Zone Corrosion Inspections

Supplemental Information

- API RP 651
- NACE SP 0169-2007

Regulatory References

- DOT 49 CFR 195
- West Virginia 47 CSR 63

Change Requests

Responsible Party	Action
Employee	If areas for improvement are observed or this procedure is ineffective, please submit feedback using the Change Request Form.

Revision History

Rev Date	Rev #	Request #	Section #	Description
5/24/2018	00	N/A	N/A	New WIMS Operating Requirement.

Appendix A: West Virginia Title 47 Legislative Rule, Department of Environmental Protection Division of Water and Waste Management, Series 63 – Aboveground Storage Tanks

Provide appropriate documentation that each regulated AST system is properly protected from corrosion. This documentation should include, but is not limited to, information on protective coatings, AST construction using materials that are not subject to corrosion or cathodic protection test, as applicable. 47CSR63

All existing regulated metallic ASTs in direct contact with soil or other electrolytes that are not equipped with cathodic protection will be upgraded to meet the requirements shown below.

General corrosion requirements: The owner or operator will ensure that all regulated ASTs are maintained with those corrosion prevention measures that are necessary to prevent releases.

- The owner or operator will ensure that regulated AST systems are maintained with corrosion and deterioration prevention measures until the AST system has undergone permanent closure.
- Acceptable corrosion and deterioration protection methods may include any one or a combination of various methods, such as cathodic protection systems (galvanic or impressed current), external and internal coatings, internal tank liners, storage in a manner that prevents metal contact with an electrolyte, construction out of noncorrodible material or metal construction with a noncorrodible material coating.

Cathodic Protection Systems: To the extent that a cathodic protection system is used as corrosion prevention, the owner or operator will ensure that cathodic protection systems are designed by a National Association of Corrosion Engineers (NACE) certified (or equivalent) corrosion expert and maintained to provide protection against external corrosion for the operational life of the regulated tank system (tank, tank bottoms, piping) or have provisions to allow for the periodic rehabilitation of the cathodic protection system, as needed, to affect repairs of failing or defective systems.

- For new, reconstructed, or relocated regulated tanks, the owner or operator will ensure that special consideration for monitoring the cathodic protection status of the underside of the AST bottom will be provided for in the cathodic protection system designed by the corrosion expert.
- Regulated metallic AST systems with tank bottoms in direct contact with soil or other electrolytes will be protected from corrosion, unless the tank is installed at a site that is determined by a NACE certified or equivalent corrosion expert not to be corrosive enough to cause it to have a release due to corrosion during its operating life.
- The cathodic protection system for the external bottom of a new or existing regulated metallic AST must be designed, installed, inspected, and maintained to meet or exceed the requirements for cathodic protection required by NACE Standards RP01-93, RP0169 or API 651.
- Each cathodic protection system will have an access point that enables the owner or operator to check on the adequacy of cathodic protection. The cathodic protection systems will be monitored in accordance with subsection 9.3 of this Rule.
- After installation of a sacrificial anode system, measurements of AST-to-soil potential must be made no sooner than 60 days and no later than 180 days after installation of the cathodic protection system by a person who, at a minimum, is NACE certified as a cathodic protection

tester. If inadequate cathodic protection is indicated, the cause will be determined, and the owner or operator will ensure that necessary repairs are made within 90 days or another time period approved by the Secretary upon request of the owner or operator and for good cause shown.

- AST and piping connections of two dissimilar metals which create a galvanic cell are prohibited.
- For existing regulated AST systems certified as Fit for Service, but having cathodic protection deficiencies, the cathodic protection system will be upgraded to meet the minimum requirements of this Rule and industry standards on the schedule provided by the certifying person, but in no case later than:
  - For Level 1 ASTs, the AST system component not meeting cathodic protection standards must be upgraded or repaired and tested by June 30, 2017.
  - For Level 2 ASTs, the AST system component not meeting cathodic protection standards must be upgraded or repaired and tested by December 31, 2017.
- An existing regulated tank system that is taken out of service for internal inspection or major modification of the tank or that has been temporarily out of service and being returned to service will have the cathodic protection upgraded or repaired and tested prior to placing the AST back into service.

Operation and Maintenance of Cathodic Protection Systems: The owner or operator of a regulated AST system with cathodic protection will ensure compliance with the following requirements to ensure that releases due to corrosion are prevented for as long as the AST system is used to store fluids.

- All cathodic protection systems must be operated and maintained to continuously provide corrosion protection to the metal components of that portion of the regulated tank and piping that routinely contain fluid substances and are in contact with soil or an electrolyte.
- All regulated AST systems equipped with galvanic or impressed current cathodic protection systems must be inspected for proper operation by a qualified cathodic protection tester in accordance with:
  - Cathodic protection systems must be tested within six months of installation and every three years thereafter by a person who, at a minimum, is NACE certified as a cathodic protection tester. However, cathodic protection systems on tank bottoms in direct contact with soil or other electrolytes will be tested within six months of installation and annually thereafter; and
  - The owner or operator must maintain the results of the last two cathodic protection tests and provide those to the Secretary upon request.
- The owner or operator of a regulated AST system with impressed current cathodic protection systems must have the rectifier inspected every sixty days to ensure the equipment is operating properly. The owner or operator must maintain the results of the last six rectifier readings from the impressed current system and make those available to the Secretary for inspection upon request.
- All impressed current systems will be checked by the owner or operator and tested by a NACE certified cathodic protection tester every twelve months as part of a preventative maintenance program to minimize in service failure. The check and tests will include a check for electrical shorts, ground connections, meter accuracy, and circuit resistance. The effectiveness of isolating devices, continuity bonds, and insulators will be evaluated during this inspection.
- The impressed current source will not be de-energized at any time, including periods when the facility is closed (except during power failures or during service work on the regulated AST, underground piping or impressed current system). The impressed current source will be

equipped with a continuously operating meter or meters that display voltage, amperage, and run time to show that the system is working.

- If any inspection, monitoring, or testing indicates that the cathodic protection system is not functioning properly, the owner or operator will determine the cause and immediately initiate the necessary repairs:
  - If a cathodic protection system on a Level 1 AST system is found to be defective and the cathodic protection system is not repairable within ninety days, the owner or operator will take immediate action to remove substances from the affected AST or underground piping, as applicable, in order to protect human health or the environment.
  - Substances will not be returned to any affected part of the regulated AST system until the defective cathodic protection system has been repaired and passed a cathodic protection test.
- The criteria for determining the effectiveness of cathodic protection will be a negative (cathodic) potential of at least 850 millivolts (mV) with the cathodic protection current applied. Alternatively, a negative potential of at least 850 millivolts from instant off reading or a 100 mV shift from the instant off position is acceptable for impressed current systems. This potential will be measured with respect to a saturated copper-copper sulfate reference electrode contacting the electrolyte.
- Corrosion protection testing required by this section will be performed by a person having, at a minimum, NACE certification (or equivalent) to perform corrosion testing.

Exterior Coatings: For regulated metallic ASTs and piping, corrosion protection may consist of an appropriate external coating as specified in a nationally recognized standard or practice of a nationally recognized association, such as the Society for Protective coatings, or an independent testing laboratory.

- When exterior coatings are used as a means of corrosion protection, the owner or operator will ensure that the exterior surfaces of all regulated aboveground tanks and piping are protected by a suitable coating that prevents corrosion and deterioration in accordance with the requirements of this section.
  - The owner or operator will ensure that the coating is able to permanently bond to the regulated AST or piping and be of sufficient thickness, density, and strength to resist corrosion, deterioration, and degradation of the exterior of the AST or piping.
  - The owner or operator will ensure that the exterior tank and piping surfaces are properly prepared prior to the application of a coating, so that visible rust, moisture or foreign matter is not present immediately prior to the application of the coating.
  - The owner or operator will ensure that the exterior coating system is maintained in good condition to prevent corrosion throughout the entire operational life of the tank or piping.
  - In order to prevent AST system deterioration, the owner or operator will ensure that the regulated AST system is repaired when the following types of painting or coating failures are detected. Repairs may be made at the next scheduled maintenance activity, but in no case will the time for repairs exceed twelve months from the date of discovery for Level 1 ASTs and twenty-four months for Level 2 ASTs.
    - Rust spots
    - Blisters
    - Peeling
    - Cracking
    - Coating bond failure

- For existing regulated AST systems certified as Fit for Service, but having corrosion deficiencies of their coating, the corrosion protection will be repaired or upgraded to meet minimum requirements of this Rule and industry standards on the schedule provided by the certifying person, but in no case later than:
  - For Level 1 ASTs, the AST system component not meeting corrosion protection standards for coatings must be repaired or upgraded by June 30, 2017.
  - For Level 2 ASTs, the AST system component not meeting corrosion protection standards for coatings must be repaired or upgraded by December 31, 2017.
- An existing regulated tank system that is taken out of service for internal inspection or major modification to the tank or that has been temporarily out of service and is being returned to service will have deficiencies in the coatings upgraded or repaired prior to placing the regulated AST back into service.

Interior Linings and Coatings: Coating or lining systems may be used, as applicable, to protect tank interiors from corrosion and to meet requirements of compatibility of the AST with substances stored within the regulated AST.

- The owner or operator will ensure that coating or lining systems that are used in the regulated ASTs are designed in accordance with current codes of practices such as API 652 or associations such as NACE. Any appropriate coating that is bonded firmly to the interior surfaces may be used to protect a tank from corrosion. Specific requirements are:
  - Coatings and linings will be chemically compatible with the substance to be stored. No owner or operator will allow storage of any liquid that is not compatible with the AST system.
  - Coating material will be applied and cured in strict accordance with the manufacturer's specifications.
  - Surfaces will be prepared and inspected in accordance with applicable nationally recognized codes and standards.
  - Coatings used to protect the bottom of a tank will extend up the side of the tank a minimum of 18 inches, while some forms of lining may cover the entire tank interior.
  - Coatings will be examined for blisters and air pockets and tested for pinholes. The coating thickness will be checked to assure compliance with the manufacturer's specifications and industry standards.
  - Defects in coating or lining systems will be repaired or corrected prior to putting the tank or system into service.
- The owner or operator will ensure that interior linings or coatings are inspected by an API or STI certified aboveground storage tank inspector, NACE certified corrosion technician, or other qualified individual:
  - At installation
  - When the regulated AST undergoes a major modification
  - As warranted or recommended by the manufacturer or design engineer
  - At a minimum, at least every ten years after installation of the internal lining
- For existing regulated systems certified as Fit for Service, but having known corrosion deficiencies of their internal lining noted during inspections performed to meet requirements of subdivision 9.5.b of this Rule, the corrosion protection will be repaired or upgraded, as applicable, to meet the minimum requirements of this Rule and industry standards on the schedule provided by the certifying person, but in no case later than:
  - For Level 1 ASTs, the AST system component not meeting corrosion protection standards for internal lining must be repaired or upgraded by June 30, 2017.

- For Level 2 ASTs, the AST system component not meeting corrosion protection standards for internal lining must be repaired or upgraded by December 31, 2017.

- A regulated existing tank system that is taken out of service for internal inspection or major modification to the tank or that has been temporarily out of service and is being returned to service will have deficiencies in the internal lining upgraded or repaired prior to placing the AST back into service.

Applicability

Franchise Applicability:

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Atlantic Gulf	Northeast G&P	West	
Gulf East	Bradford Supply Hub	Four Corners Area	Conway
Gulf West	Ohio River Supply Hub	Piceance	Overland Pass Pipeline
Eastern Interstates (Transco)	Susquehanna Supply Hub	Northwest Pipeline	Anadarko/Mid-Continent
	Utica Supply Hub	Niobrara	Barnett
		Southwest Wyoming	Eagle Ford
		Wamsutter	Haynesville
			Permian

General Applicability:

Federal Regulator		State Regulator[1]	
PHMSA 192	PSM/OSHA 1910.119	New Mexico	North Carolina
PHMSA 195	OSHA other	Colorado	New York
EPA RMP	BSEE	Texas	Other: add below
EPA other	Other: add below		
	PHMSA 193		

[1] Identify applicable States with unique state requirements that have been included in the procedure. Include the applicable State regulation in the Regulatory Reference section.