External Corrosion Control of Gas Facilities

SUMMARY

This utility standard establishes requirements for external corrosion control of natural gas facilities per the Code of Federal Regulations (CFR), Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Subpart I, "Requirements for Corrosion Control."

The requirements apply to all gas gathering facilities, storage facilities, transmission facilities, and distribution facilities owned by Pacific Gas and Electric Company (PG&E or Company).

TARGET AUDIENCE

Personnel engaged in or supervising gas transmission, gathering, storage, or distribution corrosion control work including, but not limited to, corrosion engineering services, station engineering, gas distribution engineering and design, transmission engineering, pipeline engineering, mapping, estimating, general construction, maintenance and construction, corrosion operations, gas operations quality management, leak survey, gas control technicians, asset strategists, strength testing, and integrity management; and contract support workforce personnel performing external corrosion control work

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REQUIREMENTS

1 Program Objectives

1.1 The external corrosion control program outlines the Company's commitment for achieving the following goals:

1. Protect metallic gas distribution, local transmission, backbone transmission, gathering, and storage lines and compressed natural gas (CNG) houselines from external corrosion.

2. Remediate cathodic protection deficiencies on the metallic facilities listed in Subsection 1.1.

3. Store and maintain records and information required for demonstrating adequate cathodic protection for the metallic facilities listed in Subsection 1.1.

4. Comply with regulatory requirements and Company-established utility procedures.

1.2 The requirements within this procedure may be bypassed by using the guidance document variance (formerly "waiver") process, per Utility Procedure TD-4001P-07, "Gas Guidance Document Variance Process," provided 49 CFR 192, Subpart I, requirements are met.

Variances must be submitted to corrosion engineering personnel for evaluation.

2 Roles and Responsibilities

2.1 This utility standard lists external corrosion control roles and responsibilities. The standard does not prohibit personnel from performing tasks not associated with their job role (i.e., personnel may perform any task they are properly trained and qualified to perform).

2.2 External corrosion control program directors, managers, superintendents, and supervisors are responsible for ensuring that personnel are properly trained and that they comply with Company documentation requirements as presented in this standard.

2.3 The following groups typically perform and/or support the following requirements of this standard:

1. Integrity management personnel analyze corrosion inspection data to ensure pipe integrity and to investigate anomalies.

2. Corrosion engineering services personnel design facilities, evaluate cathodic protection criteria, and select appropriate coatings for new pipe.

3. Engineering and design personnel design facilities in accordance with the requirements of this standard.

4. Corrosion operations personnel perform cathodic protection monitoring and restoration and maintain corrosion control records.

Subsection 2.3 (continued)

5. Gas operations maintenance and construction personnel and gas construction personnel support cathodic protection monitoring and support cathodic protection restoration with construction activities as needed.

6. Asset strategy personnel establish maintenance plans and create or coordinate requests for work (RWs)

7. Mapping personnel document cathodic protection equipment and inspection records in SAP® and ensure the records are mapped in the geographic information system (GIS).

3 External Corrosion Control Requirements

3.1 Metallic pipelines must be protected from external corrosion per 49 CFR 192, Subpart I.

3.2 Each new, reconditioned, converted, or replaced buried metallic pipeline facility must be protected against external corrosion as follows:

1. It must have an approved external protective coating.

2. It must be cathodically protected within 1 year after completion of construction.

3.3 It is a Company practice to cathodically protect each buried metallic pipe facility, including temporary metallic pipe facilities that will be in service for more than 1 year.

Any exemptions allowed per 49 CFR §192.455, “External corrosion control: Buried or submerged pipelines installed after July 31, 1971,” and 49 CFR §192.457, “External corrosion control: Buried or submerged pipelines installed before August 1, 1971,” must be approved in writing by corrosion engineering personnel.

3.4 Each cathodic protection system must provide a level of cathodic protection that complies with applicable criteria listed in Section 5 of this standard and in 49 CFR §192.463, “External corrosion control: Cathodic protection.”

3.5 The level of cathodic protection must be controlled to prevent damage to the protective coating or pipe per 49 CFR §192.463(c). See Subsection 5.4 of this standard for more information.

3.6 IF the Company has knowledge that any portion of a buried pipeline is exposed (removal of cover by excavation or natural means),

THEN the exposed portion must be examined for evidence of external corrosion AND a pipe-to-soil reading must be taken if the pipe is bare or if the coating is deteriorated or removed.

1. IF external corrosion requiring remedial action is found (per Utility Procedure TD-4100P-05, “Selection of Steel Gas Pipeline Repair Methods”),

   THEN the Company must investigate circumferentially and longitudinally beyond the exposed portion to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion. Indirect inspection data can be used to satisfy this requirement.

2. Refer to 49 CFR §192.459, “External corrosion control: Examination of buried pipeline when exposed.” See Utility Procedure TD-5100P-01, “Leak Repair and Pipe Inspection Documentation,” Form TD-5100P-01-F01, “Leak Repair, Inspection, Gas Quarterly Incident Report (A-Form),” Form TD-5100P-01-F03, “Pipe Inspection Form,” and related job aids for how PG&E implements this requirement.

4 Protective Pipe Coating

4.1 External protective pipe coating applied for the purpose of external corrosion control must meet the requirements of 49 CFR §192.461, “External corrosion control: Protective coating,” and *Gas Transmission and Distribution Manual: Corrosion Control Volume* (TD-4180M), Section 2: Gas Documents, General, “Coating and Wrapping (E Series).”

4.2 External protective pipe coating applied for the purpose of external corrosion control, whether conductive or insulating, must meet the following requirements of 49 CFR §192.461(a):

- Be applied on a properly prepared surface
- Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture
- Be sufficiently ductile to resist cracking
- Have sufficient strength to resist damage due to handling and soil stress
- Have properties compatible with any supplemental cathodic protection

4.3 External protective coating that is an electrically insulating type must also have low moisture absorption and high electrical resistance per 49 CFR §192.461(b).

4.4 External protective coating must be inspected just before lowering the pipe into the ditch and backfilling the ditch. Any damage detrimental to effective corrosion control must be repaired per 49 CFR §192.461(c).

4.5 External protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks per 49 CFR §192.461(d).

4.6 IF coated pipe is installed by boring, driving, or other similar methods,

THEN precautions must be taken to minimize damage to the coating during installation. Testing must be performed to ensure there is minimal coating damage during bore installation per 49 CFR §192.461(e).

5 Cathodic Protection Criteria

5.1 Cathodic Protection Criteria Levels

As indicated by 49 CFR §192.463, each cathodic protection system must provide a level of cathodic protection that complies with one or more of the criteria below for steel pipe, which is the most anodic gas-carrying metal within the cathodic protection area (CPA):

1. **Pipe-to-soil (P/S) potential – rectifier on:** Cathodic protection areas are considered adequately protected when the P/S potentials are −850 millivolts (mV) or more negative, with reference to a copper-copper sulfate electrode, with cathodic protection current applied. Voltage (IR) drop is part of this potential measurement and must be considered per Subsection 5.3.

2. **Instant-off P/S potential – rectifier off:** Cathodic protection areas are considered adequately protected when the lowest P/S potentials are −850 mV or more negative, with reference to a copper-copper sulfate electrode, immediately after the current is interrupted.

3. **100 mV polarization shift:** P/S potentials, with current briefly interrupted to eliminate IR drop, must be at least 100 mV more negative than the native or depolarized potential. See Utility Bulletin 304, “Reading Coupon Test Stations,” and Utility Bulletin 304, Attachment 1, “Gas Construction and Maintenance – Demonstration of Compliance with 100 mV Shift Criteria Using a Coupon Test Station,” for using a coupon test station to demonstrate compliance with the 100 mV shift criteria.

5.2 Reference Half-Cells (Reference Electrodes)

Potential measurements must be taken between the pipe and a saturated copper-copper sulfate half-cell contacting the electrolyte. See Utility Procedure TD-4180P-202, “Copper-Copper Sulfate Reference Electrodes,” for ordering and maintenance instructions. Using other standard reference half-cells requires written approval from corrosion engineering personnel.

5.3 Voltage (IR) Drop Considerations

1. The IR drop in the measurement circuit must be considered when interpreting the results of P/S on-potential measurements, per 49 CFR §192 Appendix D—Criteria for Cathodic Protection and Determination of Measurements, Section II, “Interpretation of voltage measurement.”

Subsection 5.3 (continued)

2. Elements of the measuring circuit that may cause IR drop include the voltmeter, reference cell (reference electrode) placement, reference cell contact resistance, test leads, coating resistance, and pipe and soil resistance.

    a. **Voltmeter:** P/S on-potential measurements must be taken with an approved electronic voltmeter, having input impedance equal to or greater than 10 megaohms.

    b. **Reference cell placement:** The reference cell must be placed as close as possible over the pipe. At meter risers, the reference cell should be placed approximately 6 to 12 inches from the riser and over the service line.

    c. **Reference cell contact resistance:** The ground (electrolyte) must be wet when measuring the P/S on-potential.

    d. **Test leads:** IR drop in the test leads is insignificant since only approved voltmeters and test leads are used for taking P/S on-potential measurements.

    e. **Cathodic protection current flow:** Current flow on a pipeline from cathodic protection can cause an IR drop in the pipe and in the soil. When conducting close-interval surveys, the data must be referred to corrosion engineering personnel to determine if and how to consider the IR drop in the measurement circuit.

5.4 Overprotection

1. The amount of cathodic protection must be controlled to prevent damage to the protective coating or pipe per 49 CFR §192.463(c).

2. See Utility Procedure TD-4181P-202, “Cathodic Overprotection,” for cathodic overprotection criteria and corrective actions.

6 Cathodic Protection Design Requirements

6.1 General

Cathodic protection systems must be designed to incorporate the following requirements:

- 49 CFR §192.467, “External corrosion control: Electrical isolation”
- 49 CFR §192.469, “External corrosion control: Test stations”
- 49 CFR §192.471, “External corrosion control: Test leads”
- 49 CFR §192.473, “External corrosion control: Interference currents”
- Utility Procedure TD-4181P-101, “Cathodic Protection Area (CPA) Design and Modification”

6.2 Electrical Isolation

1. Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit, per 49 CFR §192.467(a).

2. One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control, per 49 CFR §192.467(b).

3. The Company does not install new pipeline cased crossings on steel pipeline without written approval from corrosion engineering personnel. Where pipeline cased crossings do exist, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing per 49 CFR §192.467(c).

4. Inspection and electrical tests must be made to ensure that electrical isolation is adequate per 49 CFR §192.467(d).

5. An insulating device must not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing, per 49 CFR §192.467(e).

6. Where a pipeline is located within 25 feet of electrical transmission tower footings, ground cables, or a counterpoise, or in other areas where a fault current or an unusual risk of lightning is anticipated, the pipeline must be protected against damage due to fault currents or lightning. Protective measures must also be taken at insulating devices per 49 CFR §192.467(f).

6.3 Test Stations

Per 49 CFR §192.469, each pipeline under cathodic protection must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection. Test station location intervals defined below may be modified with written approval from corrosion engineering personnel.

1. **Existing transmission pipelines:** Each transmission main should have approximately 1 test point per linear mile.

2. **New transmission pipelines:** Test stations must be installed approximately every half mile, alternating between electrolysis test stations and coupon test stations.

3. **Distribution locations:** Each distribution CPA should have approximately 2 test points per linear mile of steel distribution main.

4. **Galvanic systems:** Mains less than 100 feet in length must have at least 1 test point. Mains greater than 100 feet in length should have at least 2 test points.

6.4 Test Leads

1. Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive per 49 CFR §192.471(a).

2. Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe per 49 CFR §192.471(b).

3. Each bared test lead wire and bared metallic area at the point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and insulation on the wire per 49 CFR §192.471(c).

6.5 Interference Currents

1. Pipeline systems subjected to stray currents must have in effect a continuing program to minimize the detrimental effects of such currents per 49 CFR §192.473(a).

2. Each impressed current or galvanic cathodic protection system must be designed and installed to minimize any adverse effects on existing adjacent underground metallic structures per 49 CFR §192.473(b).

7 Cathodic Protection Monitoring

7.1 General

1. Cathodic protection systems must be monitored per 49 CFR §192.465, "External corrosion control: Monitoring," to determine whether the cathodic protection meets established criteria levels. See Subsection 5.1 of this standard for established cathodic protection criteria levels.

2. Refer to Utility Procedure TD-4181P-201, "Cathodic Protection Monitoring and Restoration," for monitoring procedures and summary monitoring tables.

3. Cathodic protection monitoring (detailed in Subsection 7.2) applies to both galvanic and impressed current cathodic protection (CP) systems.

7.2 Cathodic Protection Systems: Transmission (Backbone and Local), Distribution, Gas Gathering, and Gas Storage Pipelines

1. Annual P/S monitoring:

   a. **Monitoring frequency:** For transmission, distribution, gas gathering, and gas storage pipelines, P/S monitoring tests must be conducted at least once each calendar year, but with intervals not exceeding 15 months to the date, per 49 CFR §192.465(a).

   b. **CNG station monitoring:** Company-owned gas houselines for CNG stations must be monitored at least once each calendar year, but with intervals not exceeding 15 months to the date.

Subsection 7.2 (continued)

c. **Transmission, gas gathering, and storage monitoring locations:** For transmission, gas gathering, and gas storage pipelines, P/S monitoring tests must be conducted at approximately 1-mile intervals. The monitoring intervals must be reduced to less than 1 mile when 1-mile intervals are not adequate to determine cathodic protection effectiveness. Effective January 1, 2019, monitoring points may be located at greater intervals than 1 mile with written approval from corrosion engineering personnel.

d. **Distribution monitoring locations:** Distribution P/S monitoring tests must be conducted at approximately 2 test points per linear mile of the steel distribution pipe. At least 2 test points are required if CP system is less than 1 linear mile in length and at least 1 test point if less than 100 feet. Consider locating the test points as follows:

- Where failure of locating wire or bond will cause a section of steel main to become isolated
- At regulator stations where the station is tied to a CPA via wire
- At locations that provide additional verification of cathodic protection effectiveness in the CPA

IF the test points on an existing distribution line operating above 60 pounds per square inch gauge (psig) do not meet the criteria above,

THEN contact corrosion engineering personnel to verify that the requirements for the transmission monitoring location, detailed in Subsection 7.2.1(c), may be applied instead.

See TD-4181P-101 for monitoring-point locations.

2. Bimonthly rectifier or other impressed current power source monitoring:

a. For transmission, distribution, gas gathering, and gas storage pipelines, each cathodic protection rectifier, thermoelectric generator (TEG), solar panel cathodic protection station, or other impressed current power source must be inspected 6 times each calendar year, but with intervals not exceeding 2½ months to the date, to ensure that the rectifier is operating, per 49 CFR §192.465(b). This bimonthly inspection consists of monitoring the output voltage and output current (amperage) of each rectifier or direct current (DC) source. See TD-4181P-201 for more information.

b. In addition to the bimonthly inspection, rectifier maintenance must be completed once each calendar year, but with intervals not exceeding 15 months to the date. See Utility Procedure TD-4181P-301, “Rectifier Maintenance and Adjustment,” for more information.

Subsection 7.2 (continued)

3. Critical and non-critical bond monitoring:

   a. **Critical bonds:** For distribution, local transmission, backbone transmission, gas gathering, and gas storage pipelines, critical bonds, including each reverse-current switch, each diode, and each interference bond whose failure would jeopardize structure protection, must be electrically checked for proper performance 6 times each calendar year, but with intervals not exceeding 2½ months to the date per 49 CFR §192.465(c).

   b. **Non-critical bonds:** Other non-critical interference bonds must be checked at least once each calendar year, but with intervals not exceeding 15 months to the date, per 49 CFR §192.465(c). See Utility Procedure TD-4181P-501, "Interference Bond Monitoring," for more information.

7.3 Cathodic Protection Systems: Pipeline Cased Crossings

1. The Company does not install new pipeline cased crossings without written approval from corrosion engineering personnel.

2. Electrical isolation tests required by 49 CFR §192.467(d) must be conducted for local transmission, backbone transmission, and gas gathering buried casings, with a frequency of once each calendar year, not exceeding 15 months to the date.

   Distribution casings are in the process of being added to SAP for scheduled testing.

3. P/S monitoring of pipeline cased crossings must be conducted per TD-4181P-201.

7.4 Isolated Steel Monitoring

Separately protected sections of mains **not** in excess of 100 feet, or separately protected service lines, may be monitored on a sampling basis per 49 CFR §192.465(a).

1. For the monitoring frequency, at least 10% of all such facilities, as listed in Subsection 7.4.2, must be monitored each calendar year, with a different 10% monitored each subsequent year, so that the entire system is tested in each 10-year period per 49 CFR §192.465(a).

2. Monitoring locations include the following:

   a. Individual isolated service lines of any length, including Company-owned isolated gas houselines

   b. Isolated main segments **not** in excess of 100 feet long

3. To ensure facilities are protected until the next monitoring cycle, a drivable anode must be installed if the P/S potentials are less negative than −900 mV with reference to a copper-copper sulfate electrode, with cathodic protection current applied.

7.5 Unprotected Pipe

1. After the initial evaluation required by §192.455(b) and (c) and §192.457(b), the Company must conduct a reevaluation, not less than every 3 years at intervals not exceeding 39 months to the date, on the unprotected pipelines and must cathodically protect them in areas in which active corrosion is found, per 49 CFR §192.465(e).

   a. At a minimum, a reevaluation consists of a leak survey every 3 years and a leak-cause review of all leak repairs.

   b. Utility Procedure TD-4110P-01, "Leak Survey Process," establishes a 3-year maximum leak survey frequency for unprotected distribution lines and a 1-year maximum leak survey frequency for transmission and gas gathering lines.

2. Although 49 CFR §192.465(e) allows for periodic monitoring of unprotected pipe, it is Company policy to either put the facility under cathodic protection or replace the facility.

3. When unprotected or inadequately protected steel pipe that is neither a known isolated steel service nor a CPA is discovered, the following requirements apply:

   a. The person discovering this condition must notify corrosion operations.

   b. Corrosion operations personnel must make efforts to place the facility under cathodic protection per Section 8.

8 Cathodic Protection Restoration

8.1 Prompt remedial action (as described in subsections 8.2 through 8.4) must be taken to correct cathodic protection deficiencies on distribution, local transmission, backbone transmission, storage, and gathering lines, as indicated by monitoring, per 49 CFR §192.465(d).

8.2 Areas must be restored within 60 calendar days from the date they are found to be inadequately protected, barring extenuating circumstances. See TD-4181P-201 for more information.

8.3 CPA restoration work over 60 days:

1. IF the CPA restoration work will exceed 60 days due to extenuating circumstances,

   THEN within 60 calendar days from the date the CPA is found below adequate levels of protection, local corrosion operations must document the activity needed to restore the CPA in SAP, using the notification long text.

Subsection 8.3 (continued)

2. The documentation must include the following information, as applicable:

   - Extenuating circumstances to the extent known

     Examples of acceptable extenuating circumstances may include personnel safety, public safety, population density, environmental concerns, climatic conditions, material availability, government permitting processes, and land acquisition requirements.

   - Cause of the CPA problem (to the extent the cause is known)
   - Proposed solution
   - Actions needed to implement the solution
   - Estimated time to take those actions
   - Personnel who perform those actions

3. Personnel possessing knowledge of the restoration work must update the documentation whenever there is a milestone. A supervisor must review the action plan.

   The documentation may be updated with the following information, as needed to document CPA restoration work:

   - Incremental work completed to date
   - Detailed status updates of needed actions that have not had any significant progress from previous updates
   - Work that needs to be completed to achieve adequate protection as defined in this document

8.4 CPAs must be restored within 12 months from the date the CPA is found below adequate levels of protection, not to exceed 15 months to the date, per Pipeline and Hazardous Materials Safety Administration (PHMSA) Inspection Guideline and Interpretation #PI-89-006 for 49 CFR §192.465(d).

9 Remedial Measures

9.1 Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of Section 4 of this standard, per 49 CFR §192.483, "Remedial measures: General."

9.2 Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this standard.

9.3 Except for cast iron or ductile iron, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this standard.

10 External Corrosion Control Records

This section complies with the requirements of Utility Standard TD-4180S, "General Corrosion Control of Gas Facilities," for external corrosion control records.

10.1 Maintain distribution and local transmission line records for each CPA.

> **NOTE**
>
> SAP is used to store and maintain records and information required to demonstrate adequate cathodic protection for gas distribution and local transmission lines. Records before the implementation of SAP are available in written format.

- Maps of cathodically protected and unprotected piping
- P/S monitoring records, casing-to-soil potentials, anode readings, and rectifier readings
- SAP action plan and other corrective notification data
- Form TD-4181P-101-F01, "CPA current requirement worksheet" or equivalent
- Form TD-4181P-101-F02, "Cathodic Protection Station Report and Interference Test Form" or equivalent
- Forms TD-4181P-301-F01, "Pole-Mount Rectifier Test and Site Evaluation," TD-4181P-301-F02, "Pedestal-Mount Rectifier Test and Site Evaluation," TD-4181P-301-F03, "Panel-Mount Rectifier Test and Site Evaluation," and TD-4181P-301-F04, "Underground Rectifier Test and Site Evaluation"
- Form TD-4181P-501-F01, "Interference Bond Maintenance Log," and other bond data

10.2 Maintain backbone transmission, gathering, and storage line records for all cathodically protected pipe.

NOTE
SAP is used to store and maintain records and information required to demonstrate adequate cathodic protection for backbone transmission, gathering, and storage lines. Records before the implementation of SAP are available in Pipeline Maintenance (PLM) program or in written format.

- Location maps delineating the protected piping system
- P/S monitoring records, casing-to-soil potentials, anode readings, and rectifier readings
- SAP action plan and other corrective notification data
- Form TD-4181P-101-F02, "Cathodic Protection Station Report and Interference Test Form" or equivalent
- Forms TD-4181P-301-F01, "Pole-Mount Rectifier Test and Site Evaluation," TD-4181P-301-F02, "Pedestal-Mount Rectifier Test and Site Evaluation," TD-4181P-301-F03, "Panel-Mount Rectifier Test and Site Evaluation," and TD-4181P-301-F04, "Underground Rectifier Test and Site Evaluation"
- Form TD-4181P-501-F01, "Interference Bond Maintenance Log," and other bond data.

10.3 Retain records per the Record Retention Schedule.

Locally held office records could include:

- Annotated CPA maps and half plats
- Historical resurveys, including initial CPA assessment worksheets, CPA field resurvey checklists, CPA file review checklists (or a combination of these) from Utility Work Procedure WP4133-02, "Cathodic Protection Area Assessment / Resurvey Procedures for Distribution"
- Historical saturation surveys (to verify that the proper P/S locations are being monitored)
- Alternating current–current attenuation (ACCA) or cathodic protection hardwire current span baseline data
- Leak history reports
- Form TD-4181P-601-F01, "Casing Investigation Report – Field Data"
- Form TD-4181P-601-F02, "Casing Investigation Report"

END of Requirements

External Corrosion Control of Gas Facilities

DEFINITIONS

Annually: Once each calendar year with intervals not to exceed 15 months to the date.

Anode: The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter the solution at the anode.

Backbone transmission line: A transmission line that transports gas over long distances from the interconnection points that includes gathering systems, interstate pipelines, and storage fields.

Bimonthly: Six times per calendar year with intervals not to exceed 2½ months to the date.

Cathode: The electrode of an electrochemical cell at which reduction is the principal reaction. Electrons flow toward the cathode in the external circuit.

Cathodic protection: Prevention of corrosion of a cathode by causing it to receive current from an anode. In the corrosion process, the cathode does not corrode, while the anode does corrode.

Cathodic protection area (CPA): An area containing segments of steel pipe that are electrically bonded together and protected from corrosion by the use of impressed current or galvanic anodes.

Copper-copper sulfate electrode: The standard or reference cell used for determining the potential of metals in soil or other electrolytes.

Completion of construction: Pipeline facility is installed and operational (gas flowing).

Corrosion: The deterioration of a substance, usually metal, resulting from a reaction with its environment.

Counterpoise: A system of conductors arranged beneath a power line, located on, above, or most frequently, below the surface of the earth and connected to the footings of the towers or poles supporting the power line.

Critical bonds: Sources of protective current (such as reverse current switches, diodes, and interference bonds) whose failure would jeopardize structure (pipeline) protection and that are read bimonthly.

Depolarization: The removal of factors resisting the current in an electrochemical cell.

Distribution feeder main (DFM): A transmission pipeline that operates at a maximum allowable operating pressure of greater than 60 psig and is connected to other gas transmission lines on the upstream side and other distribution feeder mains on the downstream side. A DFM transports gas to distribution centers.

Definitions (continued)

Distribution line: A pipeline other than a gathering or transmission line. A line is a distribution line if it meets EITHER of the following criteria:

- It transports gas downstream of a distribution center, whether through a main or service line.
- It operates as a farm tap.

Electrode: A conductor used to establish contact with an electrolyte and through which current is transferred to or from an electrolyte.

Electrolyte: A chemical substance containing ions that migrate in an electric field (for example, moist soil).

Gathering line: A pipeline that transports gas from a current production facility to a gas transmission line or main. This term includes collection lines taking gas from wells.

Half-cell: A pure metal in contact with a solution of known concentration of its own ion, at a specific temperature, develops a potential that is characteristic and reproducible; when coupled with another half-cell, an overall potential that is the sum of both half-cells develops.

Impressed current: An electric current supplied by a device using a power source that is external to the electrode system. (An example is direct current for cathodic protection.)

Local transmission line: A transmission line that interconnects with backbone transmission lines or sources of supply. For this standard, local transmission lines and DFMs are grouped under the term “local transmission lines.”

Non-critical bonds: Sources of protective current whose failure would not jeopardize structure (pipeline) protection.

Polarization: The change from the open-circuit potential as a result of electrical current flowing across the electrode and electrolyte interface.

Pipe-to-soil (P/S) measurement: A measurement of the difference in potential between a pipeline and a copper-copper sulfate cell in contact with an electrolyte.

Rectifier: An electrical device that converts alternating current (AC) to direct current (DC).

Reference electrode: An electrode whose open-circuit potential is constant under similar conditions of measurement. Reference electrodes are used for measuring the relative potentials of other electrodes.

Reference half-cell: See “half-cell.”

Definitions (continued)

Transmission line: A pipeline, other than a gathering line, that meets ANY of the following criteria:

- It transports gas from another transmission line, gathering line, or storage facility to any of the following:
  a. Distribution center
  b. Storage facility
  c. Large-volume customer that is upstream of a distribution center
- It operates at or above a hoop stress of 20% specified minimum yield strength (SMYS), or it is upstream of a segment of pipe operating at or above a hoop stress of 20% SMYS.
- It transports gas within a storage field.

Voltage (IR) drop: The change in voltage that results from current flow through a resistance.

IMPLEMENTATION RESPONSIBILITIES

The gas guidance document change notification email will be sent out after this standard publishes to communicate that it is now available in the Technical Information Library (TIL).

Corrosion engineering personnel ensure that all affected personnel are aware of this standard.

Superintendents and supervisors communicate this standard to personnel who perform external corrosion work and ensure that personnel are trained and qualified to perform the tasks under their specific job classification.

GOVERNING DOCUMENT

Utility Standard TD-4180S, “General Corrosion Control of Gas Facilities”

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Code of Federal Regulations (CFR), Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Subpart I, “Requirements for Corrosion Control”

Code of Federal Regulations (CFR), Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Appendix D—Criteria for Cathodic Protection and Determination of Measurements, Section II, “Interpretation of voltage measurement”

Pipeline and Hazardous Materials Safety Administration (PHMSA) Inspection Guideline and Interpretation #PI-89-006 for 49 CFR 192.465 − May 19, 1989.

REFERENCE DOCUMENTS

Developmental References:

A.W. Peabody. *Peabody's Control of Pipeline Corrosion*. Edited by R.L. Bianchetti. Houston: NACE Press, 2001.

Utility Procedure TD-4125P-10, "Identifying Gas Transmission Assets"

Utility Bulletin TD-4181B-004, "Changes to Cathodic Protection Monitoring Frequencies"

Supplemental References:

Form TD-4181P-501-F01, "Interface Bond Maintenance Log"

Form TD-4181P-601-F01, "Casing Investigation Report – Field Data"

Form TD-4181P-601-F02, "Casing Investigation Report"

Form TD-5100P-01-F01, "Leak Repair, Inspection, Gas Quarterly Incident Report (A-Form)"

Form TD-5100P-01-F03, "Pipe Inspection Form"

Gas Transmission and Distribution Manual: Corrosion Control Volume (TD-4180M)

Utility Bulletin 304, "Reading Coupon Test Stations," and Utility Bulletin 304, Attachment 1, "Gas Construction and Maintenance – Demonstration of Compliance with 100 mV Shift Criteria Using a Coupon Test Station"

Utility Procedure TD-4001P-07, "Gas Guidance Document Variance Process"

Utility Procedure TD-4100P-05, "Selection of Steel Gas Pipeline Repair Methods"

Utility Procedure TD-4110P-01, "Leak Survey Process"

Utility Procedure TD-4180P-202, "Copper-Copper Sulfate Reference Electrodes"

Utility Procedure TD-4181P-101, "Cathodic Protection Area (CPA) Design and Modification"

Utility Procedure TD-4181P-201, "Cathodic Protection Monitoring and Restoration"

Utility Procedure TD-4181P-202, "Cathodic Overprotection"

Utility Procedure TD-4181P-301, "Rectifier Maintenance and Adjustment"

Utility Procedure TD-4181P-501, "Interference Bond Monitoring"

Utility Procedure TD-5100P-01, "Leak Repair and Pipe Inspection Documentation"

External Corrosion Control of Gas Facilities

APPENDICES

NA

ATTACHMENTS

NA

DOCUMENT RECISION

This document supersedes Utility Standard TD-4181S, "External Corrosion Control of Gas Facilities," Rev. 1a, issued 07/19/2017.

Form TD-4181S-F01, "CPA Follow-Up Action Plan," is being canceled.

DOCUMENT APPROVER

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REVISION NOTES

Where?	What Changed?
Throughout	Replaced “corrosion compliance” with “corrosion operations.” Revised the process for bypassing requirements in this standard from email-driven to Utility Procedure TD-4001P-07, “Gas Guidance Document Variance Process.”
Subsection 3.6	Updated references to Form TD-5100P-01-F01, “Leak Repair, Inspection, Gas Quarterly Incident Report (A-Form),” and to Form TD-5100P-01-F03, “Pipe Inspection Form.”
Subsection 5.2	Added reference to Utility Procedure TD-4180P-202, “Copper-Copper Sulfate Reference Electrodes.”
Subsection 6.3	Expanded the “Test Stations” subsection to include test stations on galvanic systems.
Section 7	Consolidated subsections 7.2.2 and 7.2.3 into monitoring requirements for transmission and distribution systems, and updated the galvanic and impressed current requirements per Utility Bulletin TD-4181B-004, “Changes to Cathodic Protection Monitoring Frequencies.”
Subsection 7.3	Consolidated subsections 7.2.3(a) and 7.2.3(b) into subsection 7.3, “Cathodic Protection Systems: Pipeline Cased Crossings.”
Subsection 7.4	Replaced “10%er” language with “isolated steel service.”
Subsection 7.5	Revised guidance for addressing newly discovered unprotected pipe.
Subsection 8.3	Removed references to “PLM” and canceled Form TD-4181S-F01, “CPA Follow-Up Action Plan,” which is no longer used.
Section 10	Aligned transmission and distribution recordkeeping requirements. Moved legacy records, which are important for design and troubleshooting purposes, to 10.3, “Retain records per the Record Retention Schedule,” to highlight their retention within the local office.
Definitions	Aligned “transmission,” “distribution,” and “distribution feeder main” definitions with Utility Procedure TD-4125P-10, “Identifying Gas Transmission Assets.”
TD-4181S-F01	Canceled.
TD-4181B-004	Assimilated into this revision, but not canceled because of other affected documents.