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Corrosion Control of Gas Facilities			**O-16**
Asset Type:	Gas Transmission and Distribution	**Function:**	Maintenance
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Rev. #14: This document replaces Revision#13. For a description of the changes, see Page 16.

This document also appears in the following manuals:

- *Gas Applicant Design Manual*
- *Gas Distribution Maintenance Manual*

Purpose and Scope

This numbered document describes PG&E's corrosion control program for all gas facilities, including PG&E-owned gas gathering lines, gas transmission facilities, and gas distribution facilities.

Acronyms

AWG: American wire gauge
ac: alternating current
CFR: *Code of Federal Regulations*
CP: cathodic protection
CPA: cathodic protection area
CPUC: California Public Utilities Commission
dc: direct current
ETS: electrolysis test station
E&M: Estimating and Mapping
GT&D: Gas Transmission and Distribution
HMWPE: high molecular weight polyethylene
HVac: high voltage alternating current
IGIS: Integrated Gas Information System
kV: kilovolts
LPR: linear polarization resistance
mA: milliamperes
MMscf: million standard cubic feet
MSDS: Material Safety Data Sheet
mV: millivolts
NACE: National Association of Corrosion Engineers
OM&C: Operations, Maintenance and Construction
PCM: pipeline current mapper
PLM: PipeLine Maintenance (computer scheduling and data program)
P/S: pipe-to-soil
RSPA: Research and Special Programs Administration
Vac: volts alternating current
WRO: work at the request of others (a budgeting term)

Definitions

IR Drop: The voltage change that results from current flow through a resistance
%LEL: The concentration of an explosive gas in air as a percentage of the lower explosive limit for the gas

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References	Document
Glass-Epoxy Retainer Gaskets	B-45.1
Cast Iron to Steel Insulated Transition Couplings	B-91.4
Machine Application of Polyethylene Systems (3/4" - 48" Pipe)	E-24
Field Wrapping With Cold-Applied Tape	E-25
Meter Valves	F-80
Electrolysis Test Station Connection to Main	O-10
Installation and Monitoring of Coupon Test Stations	O-10.2
Cathodic Protection Rectifiers Installation and Purchasing Data	O-11.1
Connection - Details, Wire Splices	O-12
Graphite Anodes Installation and Purchasing Data	O-13
Galvanic Anodes Installation and Purchasing Data	O-13.1
Horizontal Anodes Installation and Purchasing Data	O-13.4
Flange Insulation	O-22
Copper - Copper Sulfate Reference Electrodes	O-71
Approved Multimeters	O-72
Physical Inspection of Pipelines, Mains, and Services	D-S0353/S4112
Cathodic Protection Standards for Cased Pipeline Crossings	D-S0354/S4126
Design and Construction of Gas Distribution Facilities	S0470
Leak Survey and Repair of Gas Transmission and Distribution Facilities	S4110
Piggable Pipelines Standard	S4118
Cathodic Protection Area Assessment/Resurvey Procedures for Gas Distribution	S5467
NACE	Standard RPO169
NACE	Standard RPO177
ISO Standard	ISO 15589-1

General Information

1. Requirements for Protection

   Install all new, reconditioned, converted, or replaced buried metallic pipeline facilities with an approved coating, and cathodically protect the facilities within 1 year after the installation date. This requirement applies to all gathering lines, transmission lines, distribution mains, and services. This requirement also applies to PG&E-owned, buried, metallic gas houselines maintained and operated by gas distribution.

   Based on 49 CFR, generically:

   - Metal, gas-carrying facilities installed after July 31, 1971, shall be placed under CP within 1 year of completion of construction. Exceptions are noted in 49 CFR 192.455.
   - Metal, gas-carrying distribution facilities with effective coatings installed before August 1, 1971, with active corrosion, shall be protected.
   - Adequately coated gas transmission facilities other than compressor, regulation, and measuring stations shall be protected.

   A. Attachment A describes cathodic protection guidelines for steel mains and services.

   B. Transmission and gathering line cathodic protection requirements shall be determined either by testing or by investigating the historical current requirements. Galvanic anodes or rectifier stations shall be installed as required.

   C. Ensure the following equipment is cathodically protected: gathering lines, transmission lines, mains, services, PG&E-owned gas houselines, and other buried metallic gas facilities.

   D. When pre-August 1, 1971, previously unprotected services or mains are discovered, the party discovering this condition must report it to corrosion engineering personnel within 10 days. The previously unprotected services or mains must be put under protection within 30 days of discovery. If the restoration work is (or is expected to be) over 30 days, the "CPA Follow-Up Action Plan" form must be used and developed within 30 calendar days from the date the previously unprotected services or mains are found below adequate levels of protection, as defined by the current 49 CFR 192, Subpart I.

2. Designing and Installing Cathodic Protection Areas (CPAs)

   Design CPAs according to the following guidelines:

   A. Use good judgment when engineering CPAs so they are not excessively large or small. Ideally, an area should contain no more than 50,000 square feet of coated steel pipe. This guideline may not apply to some existing systems or to long-line systems. For practical reasons, long-line transmission pipelines may deviate from this requirement.

   B. Complete the "Cathodic Protection Station Report" (Attachment C) for each rectifier location.

   C. Design and operate cathodic protection systems to ensure they do not significantly interfere with other underground metallic structures. Select rectifier sites which allow maximum separation between the anode bed and any non-PG&E gas lines, underground metallic structures, such as water lines, underground electric lines with bare neutral wires, metallic electric towers, metal-sheathed telephone or television cable, metal fence posts, electric ground rods and guy wire anchors, and similar facilities. A minimum distance of separation is any distance, verifiable through testing, that does not register interference. Employees must maintain a minimum distance of separation between all anodes and protected gas mains or services to prevent coating damage. For distribution and local transmission lines, document the results on the "Interference Test Form" (Attachment E). Interference on transmission lines should be reviewed by corrosion engineering personnel.

   D. Perform interference response testing in locations where non-PG&E facilities may be affected. Notify non-PG&E facility owners of the new or proposed rectifier sites or of the possibility of increased current outputs. Arrange to conduct testing, if required. Testing should include interrupting the rectifier current and measuring the on and off P/S potentials on nearby non-PG&E facilities to identify the maximum setting the rectifier could be adjusted to and not require additional interference tests. Measure and record hard wire current flows, when necessary. Document the results using the "Interference Test Form" (Attachment E). It is recommended that the highest rectifier reading that does not interfere with other's facilities and does not cause the P/S readings on the gas facilities to exceed -1,600 mV be determined and documented on the "Interference Test Form" (Attachment E). If P/S potentials do exceed -1,600 mV, see Item 3A(3) on Page 6.

   E. For proposed sites, consider establishing temporary drains to measure potential influences and cathodic protection current necessary to protect the area.

   F. Transmission line compressor stations, terminals, and other major pipeline stations shall be protected separately when practical.

   G. Insulating devices may be used in underground vaults. Take care to prevent possible electrical arcing. Use only approved flanges, gaskets, and insulating sleeves for insulating purposes (as described in Numbered Document O-22 or Numbered Document B-45.1). Design the facility to prevent accidental contact or shorting across the insulating device (i.e., avoid using foil-backed sound insulation on vault lids; it could fall and contact the insulating device).

   H. It may be necessary to provide grounding or other protection in the following cases:

      (1) On pipelines which closely parallel HVac electric transmission lines.

      (2) On pipelines where the anticipated or measured voltage between the pipeline and ground exceeds 15 Vac open circuit or has a source current capacity of 5 mA. For example, protect pipelines that parallel 230 kV or 500 kV HVac circuits of appreciable distance (over 1 mile) and are within 1,000' of an HVac conductor, and any pipeline that parallels an HVac circuit for any distance when the separation is small (less than 1,000').

      (3) On pipelines where electrical transmission towers are present.

      The need for special precautions is greater when electric loads are higher, and when pipelines are well-coated and/or installed in high-resistance soil. These precautions apply to both pipelines under construction and pipelines operated under the conditions described in this section (Item 2H). Contact corrosion engineering personnel for further evaluation. This applies for both personnel safety and corrosion control reasons.

   I. Install wire test leads according to Numbered Document O-10 and at the following locations:

      (1) Consider when existing facilities are exposed (Type A installation as shown in Numbered Document O-10).

      (2) On both sides of buried, insulated fittings (Type D installation as shown in Numbered Document O-10).

      (3) On pipeline and casing at new cased crossings (Type B installation as shown in Numbered Document O-10).

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(4) Consider installations at crossings with other metallic pipelines (Type C installation as shown in Numbered Document O-10,with the non-PG&E facility owners consent).

(5) For distribution, add enough additional locations to ensure that the pipeline is accessible at least every 3 blocks.

(6) For new transmission pipeline construction, install an ETS station every 2,500' (Type A installation as shown in Numbered Document O-10) and a coupon test station (Numbered Document O-10.2) every mile where feasible.

(7) Consider installing an ETS on each side of newly installed rectifiers (Type F installation as shown in Numbered Document O-10).

(8) When installing numerous plastic services on a steel main, test leads are required every 1,500' unless there is sufficient access to the pipeline at existing test leads or existing steel services.

J. Where stray currents from non-PG&E protection systems, both cathodic and anodic, are detrimentally affecting the cathodic protection of PG&E gas lines, contact the non-PG&E facility owners and take corrective measures to mitigate or eliminate the stray current condition. Non-PG&E protection systems may include pipelines, transit systems, telluric earth currents, etc. When other's facilities are to be installed near existing PG&E gas-carrying facilities and these foreign facilities are likely to cause interference to PG&E's gas-carrying facilities, then the other party should be contacted and before-and-after readings should be taken regarding PG&E's facilities. If interference is encountered on distribution lines, the third party must be informed of the interference and be required to correct it. If interference is encountered on transmission lines, contact corrosion engineering personnel. This investigative work should be charged to WRO expense.

K. For local transmission and distribution piping, clear all CPA contacts before designating the CPA as protected. Before excavation, when practical, confirm the location of underground contacts with current span calculations as well as with a locator (PCM, Tinker, or pipe locator). Cathodic protection systems will be considered adequately protected when the lowest P/S on-potential is a minimum of -850 mV with reference to copper-copper sulfate electrode with protective current applied with IR drop considered (See Item 7 on Page 12). Other NACE-recognized protection criteria may be used when the -850 mV on-potential criteria is not practical. Obtain baseline current profiles with a PCM unless extenuating circumstances (such as the gas main running in the middle of the street) dictate otherwise. Find and eliminate contacts resulting in PCM currents to 15 mA and hard-wire currents to 50 mA. It is typical that the PCM transmitter current is set at one-third of the CP current during "final span down."

L. When trying to account for current on transmission and gathering lines, employees may use a combination of protective current history, current requirements representative of the age and type of coating, P/S potentials, electrical surveys, or other methods to account for current when spanning is not practical (i.e., too few spans or services off the pipeline). In areas where there is reasonable evidence that other facilities contact the transmission lines, perform electrical surveys such as close interval P/S potential readings, PCM surveys, or other approved survey methods.

M. For distribution piping, the number of final P/S on-potential readings (P/S profile) which are conducted when an area is initially placed under protection or as part of a resurvey shall be one per block, if read points are reasonably available. A reading should be made at least at the beginning and the end of the main, or in close proximity of the end of the main.

N. Gathering lines and transmission lines shall use the method described above (Item 2M) except when there are no branch services. Final P/S readings should document approximately one P/S potential reading per mile, unless field conditions warrant otherwise.

O. The engineer or estimator responsible for the design of new cathodic protection facilities must consult with the corrosion mechanic and/or the operating supervisor responsible for any CPA affected by the new cathodic protection facilities regarding cathodic protection current requirements (Utility Standard S0470). Distribution and local transmission construction jobs involving the installation or deactivation of buried gas-carrying steel facilities (pipeline, main, or service), or plastic mains connected to existing buried gas-carrying steel pipelines or mains, must ensure that the cathodic protection levels of the affected steel facilities are checked by a corrosion mechanic before closing out the job. The corrosion mechanic will obtain pipe-to-soil potential measurements for all affected underground steel facilities and will record the levels found on the as-built drawings. Each applicable construction drawing associated with a construction project must be stamped with the stamp shown in Figure 1 on Page 5. A corrosion mechanic or other qualified employee* must certify that all gas-carrying underground steel facilities affected by the construction are adequately cathodically protected before closing out the job by signing the job copy stamp shown below. This stamp must be affixed to the as-built drawings for the job closeout. This requirement does not apply to new plastic services that do not involve the replacement of steel or copper piping. Report any deficiencies in the cathodic protection levels to the local corrosion supervisor for remedial action. Do not consider a construction job to be complete and ready to be closed out until adequate cathodic protection levels are noted on the installed or affected steel facilities.

For new construction or deactivation jobs on backbone transmission and gathering lines, contact corrosion engineering personnel for corrosion review.

* A qualified employee is an employee who has been operator qualified to take cathodic protection measurements.

Installation Tested or Inspected and Noted on Drawing. All Levels Satisfactory per PG&E GS&S O-16	
Qualified Employee	**Date**
Corrosion mechanic's signature is required when a CPA boundary is within the scope of the project.	

Figure 1
Stamp Used on the Construction Job Drawings

3. Cathodic Protection Maintenance and Operation

   A. Cathodic Protection Criteria

   Cathodic protection systems will be considered adequately protected when the lowest P/S potential is -850 mV or more negative, with reference to a copper-copper sulfate electrode, with cathodic protection current applied. IR drop is part of this potential measurement and must be considered per Item 7 on Page 12. For transmission and gathering lines, alternatively, the criteria listed below and other NACE-recognized protection criteria may be used, when the -850 mV on-potential criteria is not practical and when approved by corrosion engineering personnel:

   (1) 100 mV Polarization

   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. The native or depolarized potential may be established by the following methods:

   - Native potentials shall be determined by reading potentials when the pipeline is initially installed, with the cathodic protection current having never been turned on, or later, by reading fully depolarized potentials (static potentials), with the cathodic protection current off.
   - Depolarized potentials shall be determined by allowing the cathodic protection current to be interrupted long enough to demonstrate the P/S potential has depolarized to a value at least 100 mV more positive than the instant-off potential.

   The native or static potentials, used in evaluations, must be reestablished when conditions exist that may significantly affect these potentials, such as stray current, reconditioned pipe or coating, excavated sites, etc.

   (2) Coupon Stations

   Coupon stations, installed per Numbered Document O-10.2, may be used to demonstrate, evaluate and/or verify cathodic protection. Coupon stations may be used for any location and can be especially useful when the environment makes conventional measurements inaccurate or not representative. Coupons on local transmission pipe should be used to only monitor the -850 mV criterion. However for backbone transmission, at each coupon test station, three readings shall be taken and used to show compliance with a minimum of 100 mV of polarization. These are the "on" read, the "instant off" read, and the "native" read. In certain situations, a depolarization read shall also be taken. Sufficient cathodic protection shall be determined by one of these methods:

(a) P/S potential: -850 mV or more negative, with cathodic protection current applied.

(b) Disconnected pipe coupon to soil potential: -850 mV or more negative (also called "instant off" potential).

(c) 100 mV polarization, established by one of the following methods:

- At least 100 mV difference between the disconnected pipe coupon and the native coupon.
- At least 100 mV difference between an initial disconnected pipe-coupon-to-soil potential and a subsequent depolarized reading.

Other methods that reliable engineering analysis can demonstrate as equivalent to the stated compliance criteria may also be considered. These methods include, but are not limited to, use of soil corrosion probes, LPR probes, weight loss coupons, etc. These or other methods must be approved by corrosion engineering.

(3) Overprotection

Potentials more negative than -1,600 mV with protective current applied should not be present anywhere on the protected, gas-carrying structure, with the exception of annual systems and 10%ers. If a pipe potential more negative than -1,600 mV is found with rectifier current applied ("on"), additional testing is required to ensure the polarized "instant off" potential does not exceed -1,200 mV. Contact corrosion engineering personnel for information on this test and approval.

All the above potentials shall be taken with reference to a copper-copper sulfate electrode, except for zinc anode reference cell applications or for special applications approved by corrosion engineering personnel. The copper-copper sulfate electrodes shall be maintained according to Numbered Document O-71.

4. Impressed Current (Rectified) Cathodic Protection Systems

Maintain impressed current (rectified) cathodic protection systems according to the following procedures:

A. CPAs Protected by Impressed Current Systems

In areas cathodically protected with impressed current systems (rectifiers), employees shall monitor for cathodic protection effectiveness according to the schedule listed in Table 1.

B. Pipe-to-Soil Test Locations

Gas distribution test locations selected for monitoring cathodic protection effectiveness shall be at locations where the level of protection is the lowest for that CPA or shall be at locations where the loss of effective CP in the CPA would be detected.

For local transmission, backbone, and gathering lines, approximately one pipe-to-soil potential measurement shall be monitored at one mile intervals. Monitoring points should be located at intervals of less than one mile when evaluations indicate that the monitoring points at one mile intervals may not be adequate to determine cathodic protection effectiveness. Monitoring points may be at intervals greater than one mile when evaluations indicate that they are adequate for determining cathodic protection effectiveness.

Caution: Before taking pipe-to-soil readings at the meter sets and/or risers, be aware that there could be an unexpected ac potential at the meter set.

C. Monitoring Schedule

Record P/S and rectifier measurements on a PG&E "Standard Cathodic Protection Maintenance Report," Attachment D, or in PLM.

As documented in a State of California Waiver Resolution, PG&E is exempt from the Federal CPA Rectifier Inspection Monitoring Schedule as required in 49 CFR 192.465 (b). Reference: CPUC Resolution SU-39 February 23, 1996, Order Authorizing Pacific Gas and Electric Company to Deviate From General Order 112-D, Section 192.465 (b), to Exempt the Company From the Requirement of Bi-Monthly Rectifier Inspection (A copy of this waiver is located in the *Gas Distribution Maintenance Manual*, Section II, Part O). The approved monitoring schedule is shown in Table 1 on Page 7.

In some distribution rectified CPAs, yearly, routine, P/S on-potential monitoring points can be established in addition to required bimonthly monitoring points. These yearly locations do not have an "anniversary month" but may be read at any time during the calendar year. Each rectified distribution CPA must have at least one bimonthly, routine, P/S on-potential monitoring point.

Table 1 Schedule of Monitoring Intervals

	P/S Monitoring	Rectifier Monitoring
Distribution and Local Transmission	Bimonthly [1]	Annually [2]
Backbone and Gathering	Annually [2]	Bimonthly [1, 3]

[1] "Bimonthly" means six times each calendar year with intervals not to exceed 2-1/2 months.
[2] "Annually" means once each calendar year with intervals not to exceed 15 months.
[3] Rectifiers, bonds, and other sources of protective current shall be read bimonthly for transmission (backbone) only.

D. Yearly Reads

Yearly P/S on-potential monitoring points shall be established on distribution piping CPAs in the following circumstances:

- Establish yearly monitoring points at all locations where the failure of a locating wire will cause a section of steel main to become isolated and not be detected by bi-monthly monitoring.
- Where a regulator station is tied to a CPA via a wire, the regulator station shall be established as a yearly read.

These yearly read locations do not have an "anniversary month," but shall be read at least once during each calendar year. The reading should be recorded on the "Standard Cathodic Protection Maintenance Report," Attachment D. The purpose of these reads is to prove continuity and on this basis they are not required to be read after CPA restoration.

Additionally, yearly monitoring points may also be established at locations within a CPA in order to provide additional verification of the effectiveness of CP within the CPA. Corrective action must be taken to restore adequate cathodic protection current levels for any yearly P/S monitoring points found not to meet the -850 mV criteria within 30 calendar days from the day the condition was discovered. If the CPA restoration work is expected to require more than 30 days to complete, a written action plan describing the steps to be taken to restore adequate cathodic protection levels must be prepared. Action plans must be kept current until adequate cathodic protection is re-established. At least once every 30 days the action plan must be reviewed by an employee knowledgeable of the restoration work and reviewed by the operating supervisor. At least one entry must be added to the action plan during the review indicating the current status of the restoration effort. The "CPA Follow-Up Action Plan" form (Attachment B) shall be used to document cathodic protection restoration action plans. Active action plans must be kept with the "Standard Cathodic Protection Maintenance Report," Attachment D, or with the current file folder for backbone. See Item 6 on Page 10 for more information on CPA restoration.

E. Rectifier Monitoring and Maintenance

Rectifiers shall be monitored and maintained per Table 1 on Page 7. Rectifiers shall be monitored to ensure that they are functioning correctly. Both the rectifier output voltage and amperage shall be measured. When taking rectifier readings, use only an approved (Numbered Document O-72) digital multimeter. Current shall be determined by measuring voltage across the calibrated shunt while the rectifier is in operation. The current output of the rectifier will be calculated using measured voltage across the shunt and the shunt rating. Voltage shall be determined by measuring voltage across the anode and cathode terminals.

A "Rectifier Test and Site Evaluation" form (Attachment A of Numbered Document O-11.1, Form FO-11.1-A) shall be completed to ensure that rectifiers are functioning correctly and that there are no safety violations. Forms must be filed in the CPA file or equivalent, each calendar year and retained for 5 years, with intervals not to exceed the day of the previous read on the 15th month. Any safety hazard found shall be listed on the "Rectifier Test and Site Evaluation" form and shall be corrected at the time discovered. If it is not feasible to immediately correct the safety hazard, the rectifier and/or ac power supply **must** be de-energized by the employee inspecting the rectifier before leaving the rectifier. An information tag shall be attached to the rectifier indicating that it is not safe to operate. The rectifier and/or the ac power supply shall not be re-energized until the safety hazard is corrected and the information tag has been removed. If corrective work is expected to take more than 30 days to complete, a written action plan must be created and kept current using the "CPA Follow-Up Action Plan" form (Attachment B). Active action plans shall be kept with the "Rectifier Test and Site Evaluation" form.

F. Rectifier Adjustment

Clear all contacts before raising the rectifier amperage output settings. In addition, document the reason the rectifier output setting had to be increased on the back of the "Standard Cathodic Protection Maintenance Report," Attachment D, or in PLM. Acceptable reasons for adjusting the rectifier outputs include:

- Tying another CPA into the area.
- Disconnecting another rectifier in the CPA.
- Adding more steel piping to the CPA.
- Adjusting for summer dry-out conditions.
- Deterioration of pipe coating.
- Improvements for low-potential areas.
- Improvements to increase the margin of protection.
- Changes in cathodic protection currents, including interference/stray current.
- Adjustments to balance current and/or P/S potentials.

In light of the above for backbone transmission pipelines PLM has been set to automatically generate a work request to evaluate any change in rectifier output greater than 50% between monitoring cycles.

An additional interference test may be required to ensure that interference is not occurring on non-PG&E structures when the output current of a rectifier is increased. A previous interference test setting is sufficient to meet this requirement, if this new higher setting does not exceed a level where previous testing identified interference or excessive P/S readings within the CPA. Please note that for rectifiers adjusted before June 2006, the rectifier can be set at the highest interference test result plus 20%. See Item 2D on Page 3 for more information on interference testing.

G. Casing Monitoring and Maintenance

Local transmission, backbone transmission pipelines, and gas gathering pipeline cased crossings must be monitored annually (once each calendar year with intervals not to exceed 15 months) and recorded in PLM. Adequate annual monitoring at cased crossings includes a measurement of the P/S potential of the pipeline and the casing-to-soil potential of the casing. The casing is considered to be in electrical contact with the pipeline when the casing-to-soil potential is -800 mV or more negative and/or the difference between the P/S potential and the casing-to-soil potential is less than 100 mV. If one or both of these two conditions are found, further testing as described in Utility Standard D-S0354/S4126 is required. In addition to the P/S measurement and the casing-to-soil measurement, an approved hazardous atmosphere test instrument must be used to sample the atmosphere of casing vent(s) or the ground near the end of the casing if no vents are present. The as-found natural gas concentration inside the vent(s) or on the ground must be reported in %LEL. Any atmosphere test measurement that indicates an explosive gas concentration above 0%LEL in the vent or on the ground must be investigated to determine if a pipeline leak exists.

If possible, both of the described tests above must be performed on each casing, but as a minimum each casing must comply with one of the established criterion in order to be considered electrically isolated from the pipeline.

More information on casing monitoring and maintenance requirements is included in Utility Standard D-S0354/S4126. Also, Utility Standard D-S0354/S4126 includes the procedure for monitoring casings without vents and wires. This is a program centrally managed by corrosion engineering personnel. The local divisions and districts are not to keep records on this program.

Cased pipeline crossings that are found to be contacted (the casing is in electrical contact with the pipeline) shall be reported to corrosion engineering personnel within 30 days of discovery of the contact. Contacted casing reported to corrosion engineering personnel will be remediated as part of the contacted casing remediation program administered by corrosion engineering personnel. Once included in the contacted casing remediation program, the cased crossing will be evaluated and assigned a priority number and listed on the current list of contacted cased crossings. Contacted cased crossings will be remediated as resources become available. An action plan for contacted cased crossings shall be maintained by the local maintenance organization and shall consist of a standard contacted cased remediation plan, a description of the contacted case remediation program, and confirmation from corrosion engineering personnel that the particular casing is in the contacted casing program. In the year that a contacted casing is scheduled for remediation, the project manager responsible for the remediation work will prepare an individualized action plan for the work to attempt to clear the casing contact, anticipated to be performed during the year. The project manager will forward a copy of the action plan to the local maintenance organization to be included in the action plan for the contacted casing. The project manager shall update the action plan every 30 days and forward a copy of the most recent version of the action plan to the local maintenance organization to be included in the action plan for the contacted cased crossing.

H. Remote Monitoring

Cathodic protection rectifier locations, or P/S locations, can be monitored remotely to meet PG&E requirements. The gas distribution and transmission cathodic protection remote monitoring system will be programmed to automatically measure the rectifier output current and voltage, or the P/S potential, at least once each day and report a reading weekly under normal conditions.

At the first of each month, the corrosion mechanic will record the remote reads on the "Standard Cathodic Protection Maintenance Report," Attachment D, or in PLM for the CPAs that are due that month. For rectifiers, the readings should be recorded on the "Standard Cathodic Protection Maintenance Report," Attachment D, or in PLM for the readings that are due that month.

The gas distribution and transmission remote P/S and rectifier system will initiate an alarm if a reading drops below -850 mV, is out of range for a prescribed time period, or if any other prescribed alarm conditions exist. The alarm information will be sent to a central server and then sent to PG&E. The local maintenance supervisor or a maintenance planner will receive the remotely-generated rectifier or P/S alarm information and will take timely steps to correct deficiencies. In addition, any pipe-to-soil or rectifier alarm shall be recorded on the "Standard Cathodic Protection Maintenance Report," Attachment D, or in PLM, along with the date on which the alarm was received. Any field-based system alarm shall be treated as if it is a positive indication that the rectifier voltage or current output has changed dramatically or that the P/S potential at that location does not meet the minimum criteria of -850 mV or more negative (see Item 6 on Page 10).

I. Review and Assessment

Review the gas distribution CPAs using the "CPA Assessment Worksheet" at 6-year intervals, not to exceed the final day of the 6th year, using Utility Standard S5467. In addition, corrosion engineering personnel can decide to perform third party QA of resurveys for cause.

5. Galvanic Cathodic Protection Systems

Maintain galvanic cathodic protection systems according to the following procedures:

A. Monitor facilities protected with galvanic anodes by using P/S potentials as follows:

(1) Annual

Monitor isolated gas distribution piping segments that are over 100' long but less than or equal to 8 blocks of steel main or 1 mile of steel main at least once each calendar year, but with intervals not to exceed 15 months from the day of the previous read. Monitoring includes plastic systems using locating wire to distribute protection to steel service risers, steel pipes, steel valves, etc. Consider monitoring these sections more frequently, as conditions justify. Any P/S potential that is found to be less negative than -850 mV must be restored within 30 calendar days from the day it was discovered. If the CPA restoration work is expected to require more than 30 days to complete, a written action plan must be created and maintained current using the "CPA Follow-Up Action Plan" form (Attachment B). Active action plans are to be kept with the annual read book.

(2) Bimonthly

For gas distribution galvanic systems that contain more than 8 blocks of steel main or more than 1 mile of steel main, monitoring shall be conducted bimonthly (not to exceed 2-1/2 months) and read not less than six times per year. Any P/S potential that is found to be less negative than -850 mV must be restored within 30 calendar days from the day it was discovered. If the CPA restoration work is expected to take more than 30 days to complete, a written action plan must be created and kept current using the "CPA Follow-Up Action Plan" form (Attachment B). Active action plans are to be kept with the bimonthly read book.

(3) 10%er Monitoring

Monitor individual isolated services of any length at least once each 10 years. This includes individually buried, metallic fittings, PG&E-owned gas houselines, and isolated main segments less than 100' long. Monitor at least 10% of all such facilities each year. Each successive year, monitor a different selection of at least 10% of the facilities. Any "10%er" read that is found to be less negative than -850 mV must be restored within 30 calendar days from the day it is discovered. If the CPA restoration work is expected to require more than 30 days to complete, a written action plan must be created and maintained current using the "CPA Follow-Up Action Plan" form (Attachment B) until adequate P/S potentials are restored. Active action plans will be kept in the 10%er read book.

(4) Yearly

Yearly P/S on-potential monitoring points shall be established on distribution piping CPAs in the following circumstances:

- Establish yearly monitoring points at all locations where the failure of a locating wire will cause a section of steel main to become isolated and not be detected by bi-monthly monitoring.
- Where a regulator station is tied to a CPA via a wire, the regulator station shall be established as a yearly read.

These yearly read locations do not have an "anniversary month," but shall be read at least once during each calendar year. The reading should be recorded on the "Standard Cathodic Protection Maintenance Report," Attachment D. The purpose of these reads is to prove continuity and on this basis they are not required to be read after CPA restoration.

Additionally, yearly monitoring points may also be established at locations within a CPA in order to provide additional verification of the effectiveness of CP within the CPA. Corrective action must be taken to restore adequate cathodic protection current levels for any yearly P/S monitoring points found not to meet the -850 mV criteria within 30 calendar days from the day the condition was discovered. If the CPA restoration work is expected to take more than 30 days to complete, a written action plan must be created and kept current using the "CPA Follow-Up Action Plan" form (Attachment B). Active action plans are to be kept with the bimonthly read book.

B. Review the gas distribution CPAs and bimonthly galvanics as noted in Item 5A(2) on Page 9, using the "CPA Assessment Worksheet(3)" at 6-year intervals, not to exceed the final day of the 6th year, using Utility Standard S5467. In addition, corrosion engineering personnel can decide to perform third party QA of resurveys for cause.

6. CPA Restoration

A. Cathodic Protection Restoration for Distribution and Local Transmission

(1) Schedule CPAs for restoration on distribution and local transmission lines when the areas show P/S on-potentials to be below adequate levels of protection. Check and record rectifier readings on the "Standard Cathodic Protection Maintenance Report," Attachment D, or in PLM before restoring a CPA. Restore areas within 30 calendar days from the date they are found to be inadequately protected (barring extenuating circumstances). Document the reason(s) for any delays in the restoration work. Once restored, an area shall have approximately the same P/S on-potentials and rectifier output as existed before the level dropped, unless re-evaluation of the system indicates that different values are more appropriate. After the CPA has been restored and re-polarized, record final P/S on-potential and rectifier measurements on the "Standard Cathodic Protection Maintenance Report," Attachment D, or in PLM.

(2) Extenuating circumstances may cause a CPA's restoration to go beyond the 30-calendar-day timeframe. Examples of acceptable extenuating circumstances may include employee safety, public safety, population density, environmental concerns, climatic conditions, material availability, government permitting processes, and land acquisition requirements. The operating supervisor along with the corrosion mechanic shall determine if CPA restoration work is being delayed by an acceptable extenuating circumstance.

Some suggested interim, or in some cases, permanent steps that can be taken to resolve or mitigate the down time or the extent of the downage area are:

- Bonding the CPA to an adjacent CPA. When bonding to an adjacent CPA for temporary restoration, the "CPA Follow-Up Action Plan" form (Attachment B) must be used and maintained until the bond is removed and/or a permanent repair is made.
- Appropriately increasing rectifier output (see Item 4F on Page 8).

- Installing impressed current shallow bed anodes (see Numbered Documents O-13 and O-13.4).
- Installing galvanic anodes (see Numbered Document O-13.1).

Any of the above mentioned actions, if taken, shall be documented in the respective CPA records.

(3) If the CPA restoration work is (or is expected to be) over 30 days, the "CPA Follow-Up Action Plan" form (Attachment B) must be used and developed within 30 calendar days from the date the CPA is found below adequate levels of protection, as defined by the current 49 CFR 192, Subpart I. Please note that action plans shall also be established and maintained for short-term remedial actions that are in place for over 30 days. The action plan shall list and document the extenuating circumstance(s) to the extent known, the cause of the CPA problem (to the extent the cause is known), the desired solution(s), the actions needed to implement the solution, the estimated time to take those actions, and the employees who will perform those actions. The action plan shall be updated in intervals not exceeding 30 calendar days by an employee knowledgeable of the restoration work and reviewed by the operating supervisor, until the CPA restoration work is completed and the CPA shows adequate levels of protection. If the action plan exceeds 90 days, the action plan needs to be reviewed and approved by corrosion engineering personnel, the area superintendent, and the manager of technical services within 120 days. Updates to the action plan shall document the incremental work that has been completed to date, detailed status updates of needed actions that have not had any significant progress from previous updates, and the work that needs to be completed to achieve adequate protection. (Reference: WIN. DOT - DOT RSPA Interpretation Letter #16 for 49 CFR 192.465 - May 19, 1989.)

(4) Attachment B is the "CPA Follow-Up Action Plan" form. When using this action plan, file it with the respective CPA P/S maintenance worksheet. Document routine circumstances using the back of the "Standard Cathodic Protection Maintenance Report," Attachment D.

B. Cathodic Protection Restoration for Backbone Transmission and Gathering Lines

(1) Schedule CPAs for restoration on backbone transmission and gathering lines when the areas show P/S on-potentials to be below adequate levels of protection. Check and record rectifier readings on the "Standard Cathodic Protection Maintenance Report," Attachment D, or in PLM before restoring a CPA. Restore areas within 60 calendar days from the date they are found to be inadequately protected, as defined by the current version of 49 CFR 192, Subpart I (barring acceptable extenuating circumstances). Document the reason(s) for any delays in the restoration work. Once restored, an area shall have approximately the same P/S on-potentials and rectifier output as existed before the level dropped, unless re-evaluation of the system indicates that different values are more appropriate. After the CPA has been restored and re-polarized, record final P/S on-potential and rectifier measurements on the "Standard Cathodic Protection Maintenance Report," Attachment D, or in PLM.

(2) Extenuating circumstances may cause a CPA's restoration to go beyond the 60-calendar-day timeframe. Examples of acceptable extenuating circumstances may include employee safety, public safety, population density, environmental concerns, climatic conditions, material availability, government permitting processes, and land acquisition requirements. The operating supervisor along with the operator qualified employee shall determine if CPA restoration work is being delayed by an acceptable extenuating circumstance.

Some suggested interim, or in some cases, permanent steps that can be taken to resolve or mitigate the down time or the extent of the downage area are:

- Bonding the CPA to an adjacent CPA. When bonding to an adjacent CPA for temporary restoration, the "CPA Follow-Up Action Plan" form (Attachment B) must be used and maintained until the bond is removed and/or a permanent repair is made.
- Appropriately increasing rectifier output (see Item 4F on Page 8).
- Installing impressed current shallow bed anodes (see Numbered Documents O-13 and O-13.4).
- Installing galvanic anodes (see Numbered Document O-13.1).

Any of the above mentioned actions, if taken, shall be documented in the respective CPA records.

(3) If the CPA restoration work is (or is expected to be) over 60 days, the "CPA Follow-Up Action Plan" form (Attachment B or equivalent) must be used and developed within 60 calendar days from the date the CPA is

found below adequate levels of protection, as defined by the current 49 CFR 192, Subpart I. Please note that action plans shall also be established and maintained for short-term remedial actions that are in place for over 60 days. The action plan shall list and document the extenuating circumstance(s), to the extent known, the cause of the CPA problem (to the extent the cause is known), the desired solution(s), the actions needed to implement the solution, the estimated time to take those actions, and the employees who will perform those actions. The action plan shall be updated in intervals not exceeding 60 calendar days by an employee knowledgeable of the restoration work and reviewed by the operating supervisor, until the CPA restoration work is completed and the CPA shows adequate levels of protection. If the action plan exceeds 120 days, the action plan needs to be reviewed and approved by corrosion engineering personnel, area superintendent, and manager of technical services within 150 days. Updates to the action plan shall document the incremental work that has been completed to date, detailed status updates of needed actions that have not had any significant progress from previous updates, and the work that needs to be completed to achieve adequate protection. (Reference: WIN. DOT - DOT RSPA Interpretation Letter #16 for 49 CFR 192.465 - May 19, 1989.)

(4) Attachment B is the "CPA Follow-Up Action Plan" form. When using this action plan, file it with the current file folder for the respective cathodic protection system. See Item 10B on Page 15.

7. Voltage (IR) Drop Considerations

The IR drop in the measurement circuit must be considered when interpreting the results of P/S on-potential measurements. Elements of the measuring circuit that may cause IR drop include the voltmeter, reference cell placement, reference cell contact resistance, test leads, coating resistance, and pipe and soil resistance.

A. Voltmeters: Take all P/S on-potential measurements with an approved electronic voltmeter, having an input impedance equal to or greater than 10 megaohms.

B. Reference Cell Placement: Place the reference cell as close as possible over the pipe. At risers, place the reference cell approximately 6" to 12" from the riser and over the service.

C. Reference Cell Contact Resistance: If sufficient moisture is not present, moisten the ground at a location where the P/S on-potential measurement is being taken.

D. Test Leads: Since only approved voltmeters are used for making P/S on-potential measurements, IR drop in the test leads is insignificant.

E. CP 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, refer the data to corrosion engineering personnel to determine if and how the IR drop in the pipe should be considered.

F. Soil: Evaluate the IR drop in the soil using the following considerations:

(1) The 850 mV criterion for cathodic protection was developed with an allowance of at least 50 mV for IR drop and other measurement errors.

(2) The IR drop from a galvanic anode system is usually insignificant due to the small amount of current flow. Typically, the reference cell is placed over the pipe and away from the galvanic anode.

8. Inspection and Leak Repair

Inspect a pipeline for evidence of external corrosion and take remedial action, as appropriate, any time it is exposed.

A. Make a written report of each inspection as outlined in Utility Standard S4110. Use Form 62-4060, "Leak Survey, Repair, Inspection, and Gas Quarterly Incident Report," for all distribution and transmission pipeline facilities and services. Do not mark "Corrosion" as the cause of leakage unless it is observed. If in doubt, contact corrosion engineering personnel.

B. Repair, replace, or recoat corrosion-damaged pipe according to the applicable numbered documents and utility standards.

C. Do not install anodes at leak repairs in cathodically protected areas unless they are part of a cathodic protection improvement plan or approved by corrosion engineering personnel. If anodes are installed they are to be installed per Numbered Document O-13.1.

D. Where an external corrosion leak occurs on a buried gas transmission line, a corrosion mechanic (or operator qualified person) must take a P/S on-potential measurement and a soil resistivity measurement at the leak repair site. In order to minimize the IR drop, this measurement must be taken in the ditch adjacent to the pipe surface.

If it is safe and practical, immediately take the P/S on-potential reading at the corroded site as the pipe is exposed. If low levels of protection are identified as a possible cause for the leak, take remedial measures.

E. Before excavating a suspected corrosion leak on a gas transmission line, a corrosion engineer must be contacted.

F. Where an external corrosion leak occurs on a normally cathodically protected buried gas steel distribution facility, a corrosion mechanic (or operator qualified person) must take a P/S on-potential measurement at the leak site at the time of the repair. If low levels of protection are identified as a possible cause for the leak, take remedial measures, if needed.

G. Each external corrosion leak repair on a previously reported, cathodically protected, buried metal gas distribution facility shall be reviewed and evaluated by a qualified corrosion person to determine if any cathodic protection related corrective measures are needed.

(1) If it is discovered that the facility is not under cathodic protection and is not required to be under cathodic protection, the appropriate IGIS changes shall be made. This information should be noted on the Form "A" (Form 62-4060).

(2) If the cathodic protection facility was reported as "down" at the time of the leak repair, this investigation shall be documented in the respective facility's cathodic protection maintenance record. Any actions taken or findings related to a "down" (less than -850 mV) reading shall be noted on the Form "A" and on the respective facility's cathodic protection maintenance record.

9. Internal Corrosion

A. General Requirements

Whenever corrosive substances are present in a pipeline, or whenever internal pipeline corrosion is discovered, steps shall be taken to mitigate/minimize internal corrosion. The effectiveness of the internal corrosion mitigation shall be monitored at least 2 times per calendar year, but not to exceed 7.5-month intervals. Typical monitoring/mitigation strategies include, but are not limited to, use of coupons, corrosion probes, application of inhibitor and/or biocide, liquid removal, line section retirement, etc. All findings and the mitigation plan shall be documented on the "Evaluation and Mitigation Plan for Internal Corrosion Assessment," Form FO-16-G.

Whenever steel pipe is removed from a pipeline, it and the adjacent pipe must be inspected and evaluated to determine the presence and extent of any internal corrosion. This inspection is recorded as outlined in Utility Standard S4110, using Form F4110-7, "CGT Leak Survey, Repair, Inspection, and Gas Quarterly Incident Report."

Similarly, whenever the presence of corrosive liquid is confirmed, or corrosometer probe reads are out-of-specification, a mitigation plan shall be developed. All information shall be recorded on the "Evaluation and Mitigation Plan for Internal Corrosion Assessment," Form FO-16-G. Each pipeline section may have its own internal corrosion mitigation plan, depending upon the operation and environment of that section of the system. Corrosive liquids include but are not limited to water, oil, glycol, condensate, and production fluids.

Well sites upstream of Company-owned lines that have the potential to contain standing liquids or contain gas with greater than 7 pounds per MMscf of water vapor (i.e., downstream of a wet well but upstream of dehydration facilities) should be evaluated for the presence of liquids. The result of these evaluations shall be logged on the "Evaluation and Mitigation Plan for Internal Corrosion Assessment," Form FO-16-G.

Each new transmission line and replacements made to existing transmission lines and/or components must be designed to reduce the risk of internal corrosion. Unless impracticable or unnecessary, the following are required for each new transmission line or replacements to existing transmission lines:

- Configure new installations to reduce the risk that liquids will collect.
- Equip new installations with effective liquid removal features where liquids could collect.
- Design must allow monitoring devices at locations with significant potential for internal corrosion.
- Evaluate the internal corrosion risk on downstream sections.

All new pipelines installed in areas that have the potential to contain liquids should follow Utility Standard S4118.

B. Liquids

Frequent and regular drainage of drip tubes and bottom tap drains are required to decrease the amount of liquids, and therefore decrease the potential for internal corrosion. If liquid is found, drainage should be performed monthly but not to exceed an interval of 90 days. The frequency and volume of liquids removed shall be logged. A damaged or malfunctioning drip tube or drain shall be repaired within 1 year.

When found, pipeline liquids must be sampled by the district or division, analyzed, and the results logged. To ensure the most accurate results, the "Liquid Sampling Procedure LSP-2" should be followed. If the sample has been determined by the gas engineering technical services representative to be corrosive, an internal corrosion mitigation plan shall be developed. If evidence of internal corrosion has been found, regardless of the pipeline liquid-sample analysis results, an internal corrosion mitigation plan shall be initiated at that location.

Dosage rates for chemical injection shall be determined by the gas engineering technical services representative, considering line history, expected volume of water, flow rates, and vendor recommendations. Where possible, chemical injection rates shall be geared to the volume of water suspected to be in the pipeline. Chemical injection can be continuous or batch. The chemical injection rates should be set off the total flow to ensure that gas flow rates are sufficient to deliver the chemicals to the desired location.

C. Corrosion Probes, Inhibitors, and Biocides

The effectiveness of the internal corrosion control program is usually monitored with electrical resistance probes or coupons, and the data is recorded on "Probe Data Sheets" or "Coupon Data Sheets." All electrical resistance probe readings should be taken and logged at monthly intervals, but not to exceed an interval of 90 days, for the life of the system or until the probe is retired from service. The effectiveness of chemical treatments can be evaluated by measuring the residual inhibitor and/or biocide concentrations in the liquids.

All inhibitor and biocide injection sites must be located on a map or form, and information including the type of chemical, the volume of the chemical tank, and the location shall be sent to the district's environmental coordinator in GT&D. These maps are to be updated as necessary since they are used to track and determine county permitting and spill plan requirements. All information regarding type, dosage rate, and volume of inhibitor and/or biocide shall be logged. All the inhibitor and biocide injection sites must have an MSDS and appropriate fire placarding, since these substances are considered hazardous materials. Chemical injection shall not be performed unless it has been established that the chemicals will be removed by a dehydrator or other means, or otherwise cannot flow into customer service lines.

D. Other

Swift retirement of idle pipelines that are potentially wet is strongly recommended, since this action significantly reduces the risk of internal corrosion in those lines and therefore eliminates the need to treat these idle pipelines with other methods, i.e., installing probes, injecting inhibitor, or commencing biocide injection.

10. Records

A. Distribution and Local Transmission Lines

Maintain records to show the location details of all protected structures. Ensure that the records contain sufficient test data to demonstrate the adequacy of installed corrosion control measures. Maintain a file folder containing location maps illustrating the protected piping system for each cathodic protection system. The file folder should also contain information on the number, types, and locations of rectifiers and anodes, a complete history of monitoring information, bond data, pipe square footage, final saturation P/S on-potentials, final current (PCM/hardwire) spans, gas facility maps, and any other pertinent information. Maintain these records for the life of the facility.

The following is a list of the records that shall be part of the CPA file folder:

- Maps of all protected facilities.
- CP station reports for each rectifier.
- Interference test reports for each rectifier.
- CP maintenance reports including a complete history of P/S monitoring records and maintenance work.
- CPA follow-up action plans.
- PCM or CP hardwire baseline data.

- Interference and other bond data.
- CPA current requirement worksheet (all historical sheets and the current sheet).
- Initial CPA assessment worksheets (see Utility Standard S5467).
- A copy of the most current saturation surveys (to verify that the proper P/S locations are being monitored).
- CPA field resurvey checklist/CPA file review checklist (see Utility Standard S5467).
- "Rectifier Test and Site Evaluation" form.
- Other pertinent information.

B. Backbone Transmission

PLM shall be used to record and maintain records and information required to demonstrate adequate cathodic protection. This includes P/S potentials, C/S potentials, rectifier readings, identified problems, and actions taken. For problems that cannot be resolved within 60 days, use action plans and tracking. Records before the implementation of PLM are available in written format.

A current file folder shall be maintained for each cathodic protection system containing:

- Location maps delineating the protected piping system.
- "Cathodic Protection Station Report" (Form FO-16-C)
- Last 3 calendar years plus year-to-date potential readings.
- Last 3 calendar years plus year-to-year date rectifier, anode, and bond readings.
- All applicable action plans.

C. Internal Corrosion Records

- "Evaluation and Mitigation Plan for Internal Corrosion Assessment," Form FO-16-G
- "Liquid Sampling Procedure LSP-2"
- Drip Tube Logs
- Corrosometer Probe Data Sheets
- Chemical Usage Reports

D. Database Management System

Use an approved computer software database management system to maintain part or all of the records and information required in Item 7A on Page 12.

11. Atmospheric Corrosion Control

A. General

This section outlines requirements for lessening the damage caused by corrosive environments to aboveground PG&E gas facilities in compliance with current CPUC General Order 112-E and 49 CFR 192.

(1) Atmospheric corrosion on aboveground or exposed piping is confirmed by corrosion pitting or substantial uniform wall thickness loss. Surface rust or passive surface oxidation does not constitute atmospheric corrosion.

(2) Coat all new pipe installed aboveground with a PG&E-approved product (Section E, "Coating and Wrapping," in *Gas Standards and Specifications*). It is strongly recommended to use an approved petrolatum wax tape on manifolds and meter sets in highly corrosive environments.

B. Distribution and Local Transmission Compliance

Comply with Utility Standard D-S0353/S4112.

C. Backbone Transmission and Gathering Compliance

(1) Aboveground pipeline facilities shall be inspected for atmospheric corrosion annually. The inspection and action taken shall be documented according to the appropriate numbered documents.

(2) Spans, aboveground station piping, air/soil transitions, and piping in pits and vaults shall be evaluated and maintained in accordance with the “Exposed Pipe Coating Program for CGT-Owned Transmission Lines” that is available from the corrosion engineering group.

Attachments

Attachment A Cathodic Protection Guidelines for Installing New, Replaced, or Transferred Steel Distribution Mains, and Steel or Plastic Services
Attachment B....... Form FO-16-B, “CPA Follow-Up Action Plan”
Attachment C....... Form FO-16-C, “Cathodic Protection Station Report”
Attachment D....... Form FO-16-D, “Standard Cathodic Protection Maintenance Report”
Attachment E....... Form FO-16-E, “Interference Test Form”
Attachment F....... Form FO-16-F, “Cathodic Protection Area Current Requirements Worksheet”
Attachment G ...... Form FO-16-G, “Evaluation and Mitigation Plan for Internal Corrosion Assessment”
Attachment H....... .... “Liquid Sampling Procedure LSP-2”

Revision Notes

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Revision 14 has the following changes:

1. Incorporated minor editing to standardize the language of related paragraphs.

Attachment A

Table 2 Cathodic Protection Guidelines for Installing New, Replaced, or Transferred Steel and Plastic Distribution Mains

Proposed New or Replaced Gas Facility / Existing Main Piping System	Steel Main	Plastic Main
Cathodically Protected Steel Main	1. Tie new steel main into existing steel main. 2. Bring up wires into an ETS. 3. Ensure adequate P/S readings on installation. 4. Contact a corrosion mechanic to ensure proper cathodic protection requirements are met.	1. Tie new plastic main into existing steel main with a transition fitting. 2. Bring locating wires up into an ETS using a Type G installation. 3. Ensure P/S readings are adequate. 4. Contact a corrosion mechanic to ensure proper cathodic protection requirements are met.
Plastic Main With a Locating Wire That is Part of a Cathodic Protection System	Not Applicable	1. Tie new plastic main into existing plastic main. 2. Bond existing plastic main locating wire to new plastic main locating wire if bonding does not cross a CPA boundary. 3. If bonding locating wires together will cross a CPA boundary bring locating wires up into an ETS and do not bond. 4. Ensure P/S readings are adequate. 5. Contact a corrosion mechanic to ensure proper cathodic protection requirements are met.
Uncoated, Unprotected Steel Main	**10’ or Less Replacement Repair, or Relocation** 1. Tie new main to existing main. 2. Install at least one 9-pound magnesium or one 5-pound zinc anode and bring up wires into an ETS. 3. Monitor in accordance with applicable leak survey requirements. **Over 10’ and All Main Extensions** 1. Insulate at each end of main-to-main connections. 2. Install the appropriate number of galvanic anodes. 3. Ensure P/S readings are adequate. 4. Monitor P/S yearly on 10% of those pipe sections which are 100’ long or less. Monitor annually if pipe length is over 100’.	1. Tie new plastic main into existing steel main with a transition fitting. 2. Bring locating wires up into an ETS using a Type G installation. 3. Ensure P/S readings are adequate. 4. Contact a corrosion mechanic to ensure proper cathodic protection requirements are met.
Cast Iron Main	**Any Length** 1. Insulate cast iron-to-steel transition with an approved insulating coupling (per Numbered Document B-91.4). 2. Install the appropriate number of galvanic anodes. 3. Ensure there are adequate P/S readings on the installation. 4. Monitor P/S yearly on 10% of those pipe sections which are 100’ long or less. Monitor annually if pipe length is over 100’.	1. Tie new plastic main into existing steel main with a transition fitting. 2. Bring locating wires up into an ETS using a Type G installation. 3. Ensure P/S readings are adequate. 4. Contact a corrosion mechanic to ensure proper cathodic protection requirements are met.

Corrosion Control of Gas Facilities

Attachment A, continued

Table 3 Cathodic Protection Guidelines for Installing New, Replaced, or Transferred Steel or Plastic Services

Proposed New or Replaced Gas Facility / Existing Main Piping System	Direct Burial Plastic Service (See Note 5) or Plastic Service Insert (See Note 6) With Non-Corrodible Riser	Plastic Service Insert With Non-Corrodible Riser Where Plastic Service Locating Wire Cannot Be Inserted Through Service Case Pipe	Plastic Service Insert Through Existing Steel Riser (See Note 7)	New or Transferred Steel Services or Steel Risers
Cathodically Protected Steel Main	1. Bond installed plastic service wire to existing steel main or existing plastic main locating wire. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at the riser valve. 4. Insulate plastic service locating wire from the inserted steel casings.	1. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to the inserted steel casing and wrap it around the tee. 2. Bond another plastic service locating wire to the plastic service case pipe at the riser end of the service case pipe and insulate the plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at the riser valve.	1. If the plastic service locating wire is needed (see Note 7), bond the plastic service locating wire to the inserted steel casing and wrap it around the tee. 2. Insulate at the riser valve.	1. Tie steel service at the steel main. 2. Insulate at the riser.
Plastic Main With a Locating Wire That is Part of a Cathodic Protection System	1. Bond installed plastic service locating wire to existing plastic main locating wire. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at the riser valve. 4. Insulate plastic service locating wire from the inserted steel casings.	1. If the plastic service locating wire is needed (see Note 7), bond the plastic service locating wire to the inserted steel casing and wrap it around the tee. 2. Bond another plastic service locating wire to the plastic service case pipe at the riser end of the service case pipe and insulate the plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at the riser valve.	1. If the plastic service locating wire is needed (see Note 7), bond the plastic service locating wire to the inserted steel casing and wrap it around the tee. 2. Insulate at the riser valve.	1. Bond steel service to the plastic main locating wire. 2. Insulate at the riser valve.

Attachment A, continued

Table 3 Cathodic Protection Guidelines for Installing New, Replaced, or Transferred Steel or Plastic Services, continued

Proposed New or Replaced Gas Facility / Existing Main Piping System	Direct Burial Plastic Service (See Note 5) or Plastic Service Insert (See Note 6) With Non-Corrodible Riser	Plastic Service Insert With Non-Corrodible Riser Where Plastic Service Locating Wire Cannot Be Inserted Through Service Case Pipe	Plastic Service Insert Through Existing Steel Riser (See Note 7)	New or Transferred Steel Services or Steel Risers
Uncoated, Unprotected Steel Main	1. Bond installed plastic service wire to existing steel main. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at the riser valve. 4. Insulate plastic service locating wire from the inserted steel casings.	1. If plastic service locating wire is needed (see Note 7), bond the plastic service locating wire to the inserted steel casing and wrap it around the tee. 2. Bond another plastic service locating wire to the plastic service case pipe at the riser end of the service case pipe and insulate the plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at the riser valve.	1. If the plastic service locating wire is needed (see Note 7), bond the plastic service locating wire to the inserted steel casing and wrap it around the tee. 2. Insulate at the riser valve.	**Any Length** 1. Insulate steel service at both the main and the riser. 2. Install at least one 9-pound magnesium or one 5-pound zinc anode on the service pipe or a driveable anode per Numbered Document O-13.6. 3. Ensure P/S readings are adequate. 4. Monitor P/S yearly on 10% of these installations.
Cast Iron Main	1. Insulate installed plastic service wire from existing cast iron main by wrapping around tee. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at the riser valve. 4. Insulate plastic service locating wire from inserted steel casings.	1. Insulate plastic service locating wire from existing cast iron main. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to the inserted steel casing and wrap it around the tee. 3. Bond another plastic service locating wire to the plastic service case pipe at the riser end of the service case pipe and insulate the plastic service locating wire from the riser by wrapping it around the service riser. 4. Insulate at the riser valve.	1. Insulate plastic service locating wire from existing cast iron main. 2. If the plastic service locating wire is needed (see Note 7), bond the plastic service locating wire to the inserted steel casing and wrap it around the tee. 3. Insulate at the riser valve.	**Any Length** 1. Install malleable iron saddle, Universal 90. Install a small section of plastic pipe to isolate the service from the cast iron main. 2. Wrap the saddle and tee according to Section E of the *Gas Standards and Specifications*. 3. Install at least one 9-pound magnesium or one 5-pound zinc anode on the service pipe or a driveable anode per Numbered Document O-13.6. 4. Ensure P/S readings are adequate. 5. Monitor P/S yearly on 10% of these installations.

Corrosion Control of Gas Facilities

Attachment A, continued

Table 3 Cathodic Protection Guidelines for Installing New, Replaced, or Transferred Steel or Plastic Services, continued

Proposed New or Replaced Gas Facility / Existing Main Piping System	Direct Burial Plastic Service (See Note 5) or Plastic Service Insert (See Note 6) With Non-Corrodible Riser	Plastic Service Insert With Non-Corrodible Riser Where Plastic Service Locating Wire Cannot Be Inserted Through Service Case Pipe	Plastic Service Insert Through Existing Steel Riser (See Note 7)	New or Transferred Steel Services or Steel Risers
Plastic Main (Insert or Direct Buried) With Locating Wire That is Not Part of a Cathodic Protection System	1. Bond installed plastic service locating wire to existing plastic main locating wire. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at the riser valve. 4. Insulate plastic service locating wire from inserted steel casings.	1. Insulate plastic service locating wire from existing plastic main locating wire. 2. If plastic service locating wire is needed (see Note 7), bond the plastic service locating wire to the inserted steel casing and wrap it around the tee. 3. Bond another plastic service locating wire to the plastic service case pipe at the riser end of the service case pipe and insulate the plastic service locating wire from the riser by wrapping it around the service riser. 4. Insulate at the riser valve.	1. If plastic service locating wire is needed (see Note 7), bond the plastic service locating wire to the inserted steel casing and wrap it around the tee. 2. Insulate at riser valve.	**Any Length** 1. Insulate steel service at both the main and the riser. 2. Install at least one 9-pound magnesium or one 5-pound zinc anode on the service pipe or a driveable anode per Numbered Document O-13.6. 3. Ensure P/S readings are adequate. 4. Monitor P/S yearly on 10% of these installations.

Notes:

1. For new mains or services, or when reconstructing plastic services by insertion, use AWG No.14 copper HMWPE wire (Code 294378). Use AWG No.10 copper HMWPE wire (Code 294414) for mains.
2. Use compression fittings and wrap them with Tac-Tape (Code 507036). Then wrap splices with electrical tape. Soldered splices may be used instead of compression fittings (refer to Numbered Document O-12).
3. Thermite weld all wire connections to steel pipe. Strap locating wire to the service line with electrical tape or Tie-Locks (Code 399093) to ensure close proximity. Tape other than electrical tape is not permitted for strapping unless approved by the corrosion supervisor.
4. Ensure that anodes are a minimum of 12" from other underground metallic facilities.
5. Strap a locating wire to the service riser aboveground, but below an insulated service valve. Use Tie-Locks (Code 399093). Do not bond the wire to the riser.
6. Do not bond plastic service locating wire to existing service case pipe or to a new, noncorrodible, prefabricated riser. If plastic service locating wire can be inserted successfully, strap it to the service riser aboveground, but below an insulated service valve. Use Tie-Locks (Code 399093).
7. Do not bond plastic service locating wire to steel main or plastic main locating wire. For distances less than 3' from the metallic service case pipe to the main, a plastic service locating wire is not required. For longer distances, bond a plastic service locating wire to a metallic service case pipe, but never to steel main or the plastic main locating wire.
8. Driveable anodes can be thermite welded or clamped.

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