Internal Corrosion Control of Gas Facilities

SUMMARY

This utility standard establishes internal corrosion control requirements for Pacific Gas and Electric Company (Company) owned gas transmission, gathering, storage, and metallic distribution facilities.

TARGET AUDIENCE

Personnel performing or supervising internal corrosion control work.

SAFETY

Potential hazards impacting the requirements governed by this standard include, but are not limited to, the following conditions:

- Chemical hazards
- Electrical hazards
- Traffic conditions
- Construction sites
- Environmental surroundings

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REQUIREMENTS

1 General

Metallic pipelines must be protected from internal corrosion in accordance with the Code of Federal Regulations (CFR), Title 49, Part 192, Subpart I, "Requirements for Corrosion Control."

- 49 CFR 192.475 "Internal corrosion control: General"
- 49 CFR 192.476 "Internal corrosion control: Design and construction of transmission line"
- 49 CFR 192.477 "Internal corrosion control: Monitoring"

1.1 Investigating Corrosive Gas

Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion. [49 CFR 192.475 "Internal corrosion control: General" (a)]

The corrosive effect of gas on pipelines is investigated through the following:

1. Gas Testing

   Gas testing at gas receipt points (including from storage, gathering, and production lines) must be performed to detect the presence of potentially corrosive constituents and determine if additional monitoring is needed. Gas testing may consist of continual monitoring using gas chromatographs, sample collection and subsequent analysis in a laboratory, or field testing using stain tubes or equivalent. Tests should measure the concentration of carbon dioxide (CO_2), hydrogen sulfide (H_2S), oxygen and water vapor present in the gas stream. See Gas Utility Standard TD-4580S, "Natural Gas Quality," for additional information if needed.

   a. Sample Collection and Analysis

      Gas testing must be performed at gas receipt points. Testing for water vapor, H_2S and CO_2 content should be performed annually, at a minimum. Additional gas testing frequencies and constituents may be required at the discretion of corrosion services. Acceptable gas sampling methods include gas chromatography, sample bottle collection, stain tubes, or equivalent. See Utility Work Procedure WP4300-18, "Sampling Natural Gas," for additional information if needed.

Section 1.1 (continued)

b. Results Interpretation

Gas testing results must be reviewed by corrosion services against the criteria presented in Table 1 to determine if additional corrosion investigation is necessary. The Gas Quality Department must notify corrosion services of gas quality testing results that exceed the criteria in Table 1 as reported by online monitoring systems within two weeks. Additional investigation may include checking for the presence of liquid, performing water testing, performing corrosion rate monitoring, and obtaining duplicate samples.

Table 1. Criteria for Additional Corrosion Investigation based on Gas Testing.

Constituent	Criteria
H_2S	More than 0.25 grains of H_2S, measured as H_2S, per one hundred standard cubic feet (4 parts per million [ppm])
CO_2	More than 1% by volume of CO_2
H_2O	More than 7 pounds of water vapor per million standard cubic feet (MMscf) at 800 pounds per square inch gauge (psig) or less; dew point over 20 degrees Fahrenheit if gas is supplied at over 800 psig

Note: The limit values in this table are generally coming from tariff limits for merchantable gas. Additional scientific assessments are required to determine what values are necessary to create a potentially corrosive environment.

c. Records

Data from gas chromatographs must be maintained by gas operations. Gas spot testing locations and results must be maintained by the associated facility. A copy of the records must be sent to corrosion services annually.

2. Liquid and Solid Sampling

NOTE

The Company considers gas to be corrosive if it contains a combination of gas and other contaminants in the presence of free (liquid) water or other electrolyte which may result in metal loss that is considered to be significant by corrosion services. Compressor oil is not considered a potentially corrosive contaminant.

Liquid sampling must be performed to monitor for the presence of potentially corrosive constituents and to determine if additional monitoring is needed.

Section 1.1.2 (continued)

a. Identifying Appropriate Sampling Locations

Liquid samples must be collected as part of maintenance activities on an opportunistic basis, including during separator maintenance, during drip blowing, during bottom tap drainage, following maintenance pigging, and during any other activities where liquids may be sampled. Liquid samples may also be collected from strategic locations selected by corrosion services.

b. Evaluating Locations Exceeding Water Vapor Criteria for the Presence of Liquids

Well sites upstream of Company pipelines 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 results of these evaluations are recorded on Gas Utility Form TD-4186P-100-F01, "Liquid Sampling Log."

c. Frequency

Liquid samples must be collected as follows:

- Except for situations of repeated exposures of the same internal surface during a completion of a task or in a short period, when a gas pipeline, vessel, pig trap, meter tube, or tank is opened a liquid sample must be collected when sufficient volume is available. Some internal surfaces (e.g., pig launchers/receivers, meter tubes, gas filters) may be repeatedly exposed several times over a short period of time in the completion of a task. In situations that fall under these parameters, contact corrosion services for a recommended sampling frequency.
- At drips and bottom taps annually, at a minimum. See Section 3, "Monitoring and Routine Maintenance."
- Following the first cleaning pig run performed as part of routine maintenance or in-line inspection. See Gas Utility Procedure TD-4186P-400, "Internal Corrosion Control: Mitigation."
- Whenever a pipeline is cut open or removed from the line and there is a capturable amount of liquid for sampling.
- IF an upset condition is known to have occurred,

  THEN a reasonable effort should be made to locate and obtain a liquid sample for analysis.

Section 1.1.2.c (continued)

- Depending on corrosion monitoring results or other considerations, Corrosion Engineering may designate a gas stream in a section of piping as corrosive. In the absence of other monitoring the location must be sampled twice per calendar year, but not to exceed 7-1/2 months to the date. However, corrosion services may recommend more frequent sampling.

- At the discretion of corrosion services.

d. Sample Collection and Analysis

Liquids must be collected and evaluated according to the procedure described in Gas Utility Procedure TD-4186P-100, "Liquid and Solid Sampling and Testing."

e. Results Interpretation

(1) Liquid sample analysis results must be reviewed to determine if additional monitoring or investigation is necessary.

- IF liquid sample collection identifies water via a positive indication on water finding paper in the field or subsequent lab analysis determines a water content greater than 5% by volume and lab test results exceed any of the criteria in Table 2 below,

  THEN an internal corrosion mitigation plan must be developed. (See Section 4)

- IF liquid sample collection identifies water via a positive indication on water finding paper in the field or subsequent lab analysis determines a water content greater than 5% by volume and lab test results DO NOT exceed any of the criteria in Table 2 below,

  THEN further review may be needed as determined by corrosion services.

- IF the field water test does not indicate free water and the results of the laboratory tests do not indicate a concentration of water in the sample greater than 5%,

  THEN the sample is considered non-corrosive and no further action is indicated.

Section 1.1.2.e (continued)

Table 2. Criteria for Additional Corrosion Investigation based on Liquid Analysis, prioritized order.

Constituent	Criteria
Bacteria (via serial dilution)	Greater than 1000 counts/mL (4th bottle indication and higher)
pH	Less than or equal to 4.3 as measured in water sample
Fe	Greater than 100 mg/l in water sample
Fe/Mn Ratio	Fe greater than 100 mg/l in water sample and Fe/Mn ratio (approximates ratio of steel) between 0.64 – 1.24 for older steel or 0.64 – 1.64 for newer steel.
Cl-	Greater than 30,000 ppm
Inhibitor	Vendor specified

(2) Liquid sample analysis results must be compared to other analysis results from the same location. Significant deviations from the average composition or the previous sample may warrant additional corrosion investigation. Additional investigation may include review of operating conditions, gas sample collection, and corrosion rate monitoring (see Gas Utility Procedure TD-4186P-300, "Internal Corrosion Control: Corrosion Rate Monitoring.")

f. Records

- Evaluations for the presence of liquids and liquid sampling results must be recorded on Gas Utility Form TD-4186P-100-F01, "Liquid Sampling Log," and, where applicable, on Gas Utility Form TD-4186P-400-F01, "Evaluation and Mitigation Plan for Internal Corrosion Assessment."
- A record of all liquid sample collection locations and results must be kept by the associated facility.
- A copy of all records must be sent to corrosion services annually per Section 8, "Records."

3. Mitigation

See Section 4 for mitigation planning.

1.2 Inspecting Internal Surface of Pipes

1. Whenever any pipe is removed from a pipeline for any reason, or whenever the interior surface of the pipeline is exposed, the internal surface must be inspected for evidence of corrosion.

   a. IF internal corrosion is found,

      THEN the following actions must be taken:

      (1) The adjacent pipe must be investigated to determine the extent of internal corrosion.

      (2) Replacement must be made to the extent required by the applicable remedial measures paragraphs of 49 CFR 192.485, "Remedial measures: Transmission lines", 49 CFR 192.487, "Remedial measures: Distribution lines other than cast iron or ductile iron lines" , or 49 CFR 192.489, "Remedial measures: Cast iron or ductile iron pipelines".

      (3) Steps must be taken to minimize the internal corrosion. [49 CFR 192.475(b)]

2. Periodically inspect facilities that are opened on a periodic basis such as:

   - Sand Caps
   - Filter separators
   - In-line inspection (ILI) launchers and receivers

3. The following documents comply with the above requirements:

   - Gas Utility Form TD-4110P-03-F01, "Leak Repair, Inspection, and Gas Quarterly Incident Report (A-Form)"
   - Gas Utility Procedure TD-4186P-300, "Internal Corrosion Control: Corrosion Rate Monitoring"
   - Gas Utility Procedure TD-4186P-400, "Internal Corrosion Control: Mitigation"
   - Gas Utility Procedure TD-4100P-05, "Selection of Steel Gas Pipeline Repair Methods"

2 Design and Construction of Transmission Lines

[49 CFR 192.476)

2.1 Design and Construction: Except as provided in Section 2.2 below, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must meet the following: [49 CFR 192.476(a)] (See Section 2.5.)

1. Be configured to reduce the risk that liquids will collect in the line. [49 CFR 192.476(a)(1)]

2. Have effective liquid removal features whenever the configuration would allow liquids to collect. [49 CFR 192.476(a)(2)]

3. Allow the use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion. [49 CFR 192.476(a)(3)]

2.2 Exceptions to Applicability: The design and construction requirements of Section 2.1 above do not apply to pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007. [49 CFR 192.476(b)]

2.3 Change to Existing Transmission Line: When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate. [49 CFR 192.476(c)]

2.4 Design and Construction Records: Records must be maintained demonstrating compliance with this section. Provided the records show why incorporating design features addressing 2.1.1, 2.1.2, or 2.1.3 of this section is impracticable or unnecessary, this requirement may be fulfilled through written procedures supported by as-built drawings or other construction records. [49 CFR 192.476(d)]

2.5 The following documents comply with the above requirements:

1. New or replaced pipelines must follow applicable gas design standards including the following:

   - Gas Design Standard A-34, "Piping Design and Test Requirements"
   - Gas Design Standard A-05, "Piggable Pipeline"

Section 2.5 (continued)

2. Gas Utility Procedure TD-4186P-200, "Internal Corrosion Control Design Review," must be followed whenever a new transmission, gathering, or storage pipeline is designed or an existing one is modified. Prior to construction, corrosion services must review the design for internal corrosion threat and complete the Internal Corrosion Review Stamp (Figure 1) applied to transmission line construction drawings.

INTERNAL CORROSION (IC) DESIGN & CONSTRUCTION REVIEW		
IC Threat (Per RMP-16)	Yes	No
IC Review Action	Initial	Date
Corrosion engineering has reviewed this design and incorporated any necessary IC design and construction considerations. Documentation of the review and actions taken are in the job package and incorporated in this design.		

Figure 1. Internal Corrosion Review Stamp

3 Monitoring and Routine Maintenance

3.1 Monitoring [49 CFR 192.477]

IF corrosive gas is being transported,

THEN coupons or other suitable means must be used to determine the effectiveness of steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times per calendar year, but with intervals not exceeding 7-1/2 months to the date. [49 CFR 192.477]

- Refer to Gas Utility Procedure TD-4186-300, "Internal Corrosion: Corrosion Rate Monitoring," for corrosion rate monitoring device selection, placement, result interpretation, and records.

- Electrical resistance probes and permanently mounted ultrasonic thickness (UT) probes must be read and recorded, at a minimum, two times per calendar year at intervals not to exceed 7-1/2 months to the date, unless indicated otherwise by corrosion services. Readings must continue for the life of the system or until the probe is retired from service.

- Corrosion rate monitoring coupons must be installed for 1 month at a minimum, but must be changed two times per calendar year at intervals not to exceed 7-1/2 months to the date.

Section 3.1 (continued)

- Corrosion rate monitoring for the effectiveness of mitigation must be performed two times per calendar year at intervals not to exceed 7-1/2 months to the date.

3.2 Routine Maintenance

Routine maintenance activities must be performed to minimize the potential for corrosive conditions within the pipeline system. These activities must be performed in addition to corrosion mitigation activities and in locations where active corrosion has not been identified.

1. Drips

   Drip maintenance is vital to maintaining the integrity of drips. Routine drip blowing must be performed to remove liquids that have accumulated in drips.

   a. Frequency.

      - Drips must be blown annually, at a minimum.

        - IF 500 ml or more of liquid is present,

          THEN drips must be blown bi-monthly, not to exceed 2-1/2 months to the date, unless indicated otherwise by corrosion services.

        - IF a drip is found dry (less than 500 ml of liquid) for 6 consecutive inspections,

          THEN the drip can be blown once each calendar year, not to exceed 15 month intervals.

      - A damaged or malfunctioning drip tube must be repaired or removed within 3 years, not to exceed 39 months to the date unless exempted by corrosion services.

   b. Sampling.

      Samples must be collected if liquids are present when drips are blown. Samples must be collected, tested, and results interpreted according to Section 1.1.2 and Gas Utility Procedure TD-4186P-100, "Internal Corrosion - Liquid and Solid Sampling."

Section 3.2 (continued)

c. Documentation.

Drip blowing information must be recorded on Gas Utility Form TD-4186P-100-F01, "Liquid Sampling Log." A copy of each record must be sent to corrosion services annually.

2. Bottom Taps

Bottom tap drainage is required to decrease the amount of liquids present in the pipelines.

a. Frequency.

- Bottom taps must be drained annually, at a minimum.
  - IF 500 ml or more of liquid is present,

    THEN bottom taps must be blown bi-monthly, not to exceed 2-1/2 months to the date, unless indicated otherwise by corrosion services.
  - IF a bottom tap is found dry (less than 500 ml of liquid) for 6 consecutive inspections,

    THEN the bottom tap can be drained once each calendar year, not to exceed 15 month intervals to the date.
- A damaged or malfunctioning bottom tap must be repaired or removed within 3 years, not to exceed 39 months to the date unless exempted by corrosion services.

b. Sampling.

Samples must be collected if liquids are present when bottom taps are drained. Samples must be collected, tested, and results interpreted according to Section 1.1.2 and Gas Utility Procedure TD-4186P-100, "Internal Corrosion - Liquid and Solid Sampling."

c. Documentation.

Bottom tap drainage information must be recorded on Gas Utility Form TD-4186P-100-F01, "Liquid Sampling Log." A copy of each record must be sent to corrosion services annually.

4 Mitigation

Internal corrosion mitigation plans must be developed as described in Gas Utility Procedure TD-4186P-400, "Internal Corrosion Control: Mitigation."

5 Idle Pipelines and Dead Legs

5.1 Swift retirement of idle pipelines that contain liquids is strongly recommended. Retiring idle pipelines significantly reduces the risk of internal corrosion in those lines and therefore eliminates the need to treat these idle pipelines with other corrosion methods.

5.2 Operational dead legs (i.e., those which have no flow because of shut valves) should be flushed annually, if practical.

6 Distribution Assets

Identification and removal of internal corrosive conditions on transmission assets greatly reduces the internal corrosion threat on distribution assets. Periodic reviews of internal corrosion issues such as liquid upsets, internal corrosion leaks, and identification of liquids must be considered in any further investigations on distribution assets.

7 Program Review

Corrosion services must perform an annual review of activities and the data related to internal corrosion of gas transmission, gathering, and storage lines at the end of each year as described in Gas Utility Procedure TD-4186P-500, "Internal Corrosion Control: Annual Review Process."

8 Records

Corrosion control records must be maintained as described in Gas Utility Standard TD-4180S, "General Corrosion Control of Gas Facilities."

- Divisions and districts must retain internal corrosion records (monitoring records, sampling analyses and data sheets) as long as the pipeline remains in service.
- Divisions and districts must send copies of internal corrosion records to corrosion services annually. However, if districts or divisions encounter a condition that is urgent or notably unusual (e.g., outside established criteria), corrosion services must be notified immediately.
- Refer to the various internal corrosion procedures for specific record keeping requirements, if needed.
- Refer to Section 2.4 for design and construction records, if needed.

END of Requirements

DEFINITIONS

Bottom Tap: Tap installed at the bottom of a pipeline designed to drain and remove liquids.

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

Corrosion Coupon: A small, carefully weighed and measured specimen of metal that provides a means of monitoring and measuring corrosivity within a system. By observing the milli-inches per year (mpy) corrosion rate of an exposed coupon, information can be gained regarding the material's life expectancy.

Corrosion Rate: The time rate of change of corrosion. It is typically expressed as depth of wall loss per unit time, or milli-inches per year (mpy).

Corrosometer: See Electrical Resistance (ER) Probes.

Dead Legs: Sections of pipe through which there is no flow. Dead legs may vary in length from a few feet to several hundred feet. A dead leg may be present all of the time or intermittently depending on pipeline operations. Dead legs are more susceptible to internal corrosion than flowing pipelines because liquid and solids that enter the dead leg have no means of being removed.

Drips: A device intended to facilitate the removal of liquids, sampling of liquids, or both.

Electrical Resistance (ER) Probes: An electronic probe that determines metal loss over time by measuring the increase in the resistance of the electrode as its cross-sectional area is reduced by corrosion. The resistance of the electrode is then compared with the resistance of the standard, non-exposed electrode.

Liquid: A substance that tends to maintain a fixed volume but not a fixed shape.

Pitting: Cavities formed in the surface of a material caused by corrosion.

IMPLEMENTATION RESPONSIBILITIES

Corrosion services ensures all impacted personnel are aware of this standard.

Superintendents and supervisors communicate this standard to personnel who perform internal corrosion control work and ensure that personnel are trained and qualified to perform these tasks.

GOVERNING DOCUMENT

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

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

49 CFR 192.475 "Internal corrosion control: General"

49 CFR 192.476 "Internal corrosion control: Design and construction of transmission line"

49 CFR 192.477 "Internal corrosion control: Monitoring"

49 CFR 192.485, "Remedial measures: Transmission lines"

49 CFR 192.487, "Remedial measures: Distribution lines other than cast iron or ductile iron lines"

49 CFR 192.489, "Remedial measures: Cast iron or ductile iron pipelines"

REFERENCE DOCUMENTS

Developmental References:

49 CFR 192, Subpart I, "Requirements for Corrosion Control"

NACE SP0106-2006, "Control of Internal Corrosion in Steel Pipelines and Piping Systems"

Supplemental References:

Gas Transmission and Distribution Manual: Corrosion Control Volume

Gas Design Standard A-05, "Piggable Pipeline"

Gas Design Standard A-34, "Piping Design and Test Requirements"

Gas Utility Standard D-S0353/S4112, "Physical Inspection of Pipelines, Mains and Services"

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

Gas Utility Procedure TD-4110P-03, "Performing and Documenting Leak Survey"

Gas Utility Procedure TD-4412P-07, "Patrolling Pipelines"

Gas Utility Procedure TD-4186P-100, "Liquid and Solid Sampling and Testing Procedure"

Gas Utility Procedure TD-4186P-200, "Internal Corrosion Control: Design Review"

Gas Utility Procedure TD-4186P-300, "Internal Corrosion Control: Corrosion Rate Monitoring"

Gas Utility Procedure TD-4186P-400, "Internal Corrosion Control: Mitigation"

Gas Utility Procedure TD-4186P-500, "Internal Corrosion Control: Annual Review Process"

Gas Utility Form TD-4110P-03-F01, "Leak Repair, Inspection, and Gas Quarterly Incident Report (A-Form)"

Gas Utility Standard TD-4580S, "Natural Gas Quality,"

Gas Utility Procedure TD-4580P-07, "Gas Quality Monitoring and Response"

Utility Work Procedure WP4300-18, "Sampling Natural Gas,"

Utility Work Procedure WP4330-02, "Removal and Control of Liquids from Gas Pipelines and Maintenance and Operation of Associated Gas Conditioning Equipment"

Gas Rule 21, "Transportation of Natural Gas"

Risk Management Procedure RMP-16, "Threat Identification"

APPENDICES

NA

ATTACHMENTS

NA

DOCUMENT RECISION

Gas Design Standard O-16, "Corrosion Control of Gas Facilities" is being replaced by the following document set:

- Gas Utility Standard TD-4180S, "General Corrosion Control of Gas Facilities"
- Gas Utility Standard TD-4181S, "External Corrosion Control of Gas Facilities"
- Gas Utility Standard TD-4186S, "Internal Corrosion Control of Gas Facilities"
- Gas Utility Standard TD-4188S, "Atmospheric Corrosion Control of Gas Facilities"
- Gas Utility Procedure TD-4181P-101, "Cathodic Protection Area (CPA) Design and Modification"
- Gas Utility Procedure TD-4181P-201, "Cathodic Protection Monitoring and Restoration"
- Gas Utility Procedure TD-4181P-202, "Cathodic Overprotection"
- Gas Utility Procedure TD-4181P-301, "Rectifier Maintenance and Adjustment"
- Gas Utility Procedure TD-4186P-100, "Internal Corrosion Control: Liquid and Solid Sampling and Testing"
- Gas Utility Procedure TD-4186P-200, "Internal Corrosion Control: Design Review"
- Gas Utility Procedure TD-4186P-300, "Internal Corrosion Control: Corrosion Rate Monitoring"
- Gas Utility Procedure TD-4186P-400, "Internal Corrosion Control: Mitigation"
- Gas Utility Procedure TD-4186P-500, "Internal Corrosion Control: Annual Program Review"

Internal Corrosion Control of Gas Facilities

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REVISION NOTES

Where?	What Changed?
All	This is a new utility standard replacing the internal corrosion control requirements portion of Gas Design Standard O-16, "Corrosion Control of Gas Facilities." O-16 is being updated and rewritten to comply with the new Company guidance document requirements, and is being reorganized and expanded into the following four standards with multiple procedures under each standard: • General corrosion control • External corrosion control • Internal corrosion control • Atmospheric corrosion control See the Guidance Document Analysis for details.

