Attachment 2

Pacific Gas and Electric Company

Corrosion Control Programs Summary Update

February 11, 2014

1. Corrosion Control Programs Assessment Background

PG&E has initiated an assessment of its overall corrosion control program to identify program improvements and to address previously filed non-compliance self-reports (under ALJ-274). Through this assessment, PG&E has identified process improvement opportunities and some areas that were not in compliance with regulatory criteria as put forth by either the Code of Federal Regulation (CFR) Part 192 Subpart I or PHMSA enforcement guidance pertaining to this subpart. PG&E is committed to correcting all program deficiencies through a risk-based approach to ensure public safety. PG&E is evaluating each issue and, where applicable, analyzing consequence and likelihood conditions to prioritize necessary remediation work. Any area of concern will be addressed immediately; thus far, PG&E has not determined any immediate safety conditions resulting from these identified compliance issues. Any remedial work to comply with regulations will be funded separately by PG&E's shareholders, not ratepayers.

PG&E has previously identified and self-reported non-compliance issues in multiple corrosion control areas, including atmospheric corrosion inspection and mitigation, alternating current (AC) interference protection, and inadequate cathodic protection (low read) mitigation. As part of its assessment, PG&E has identified additional instances of previously reported issues, as well as non-compliance issues related to its unprotected steel pipe mitigation program and a process issue with internal corrosion inspections.

Table 1 provides a summary of the corrosion control compliance issues and the governing PG&E guidance documents which will be addressed as part of PG&E's corrective action plan. PG&E has already submitted self-identified non-compliance notifications to the CPUC for most instances, but is providing an update on additional findings based on ongoing program assessments.

Table 1: Summary of Corrosion Control Compliance Issues

Description	Dates of Previous Self-Report(s)	PG&E Guidance Documents to Be Published or Revised
Atmospheric Corrosion Inspection	3/6/13, 3/29/13, 6/18/13	TD-4188S, TD-4188P-003
Atmospheric Corrosion Mitigation	3/6/13, 3/29/13, 6/18/13	TD-4188S, TD-4188P-001, TD-4188P-xxx
AC Interference - Coupling	12/19/12	TD-4182S, TD-4182P-01
Inadequate Cathodic Protection Mitigation – Distribution	6/5/12	O-16
Inadequate Cathodic Protection Mitigation – Transmission	6/5/12	O-16
Reevaluation of Unprotected Steel Pipe – Distribution	n/a	O-16
Internal Corrosion Inspections	n/a	TD-4186S, TD-4186P-100, TD-4186P-200, TD-4186P-300,TD-4186P-400

2. Atmospheric Corrosion Inspection

49 CFR §192.479-192.481 requires that pipeline operators inspect exposed piping for atmospheric corrosion at least once every three years, including customer meter sets. PG&E operates over 4.4 million customer meters and inspects these facilities for atmospheric corrosion every three years. In 2013, it was found that some meter set locations were not readily accessible (e.g. meter located in customer basement or garage) leading to the inability to complete the three-year inspections as required. In these cases, PG&E made several attempts (up to three visits) to complete the inspections, but was unsuccessful for approximately 7,000 locations.

These locations have been identified as Can't Get In (CGI) and will be addressed through a centralized program which is currently under development and designed to achieve appropriate customer contact, bundle work with other programs that have a similar access issue, and minimize customer impact.

PG&E has identified CGIs as a larger issue impacting other routine monitoring and maintenance programs, including scheduled meter changes, leak surveys, and the isolated steel services program (ISSP). The CGI program being developed in 2014 will address the gaps in these other programs as well as atmospheric corrosion inspections.

PG&E anticipates identifying additional locations requiring remedial atmospheric corrosion inspections as part of the ongoing program assessment and other data gathering initiatives such as the Pipeline Centerline Survey. As these locations are identified, they will be inspected, monitored, and maintained appropriately.

3. Atmospheric Corrosion Mitigation

49 CFR §192.479-192.481 requires that pipeline operators inspect exposed piping for atmospheric corrosion at least once every three years, at intervals not exceeding 39 months. While the CFR does not specify a mitigation timeline associated with the atmospheric corrosion inspection, PHMSA's Part 192 Corrosion Enforcement Guidance states that the appropriate timeframe to provide protection is before the next scheduled inspection (p. 122, rev. 1/22/2013). PG&E's program assessments identified that mitigation of exposed pipe at locations documented for follow-up based on the three-year inspection were not addressed promptly.

PG&E is performing a records inventory to identify potential instances of exposed pipe with documentation of atmospheric corrosion found through inspection but no associated documentation of mitigation within a 39-month timeframe following the initial inspection. To date, PG&E has identified 583 locations on transmission assets that did not meet the mitigation timeframe. PG&E is continuing a records review and expects to find additional locations on both transmission and distribution assets requiring further evaluation and possible remediation. PG&E estimates the atmospheric corrosion records inventory and documentation review to be complete by 8/31/2014 for transmission assets, which will be followed by a distribution asset records inventory.

In separate efforts, PG&E is investigating similar instances regarding exposed portions of customer meter sets. A process gap was found as the root cause. The process has been completely redesigned for 2014 to address the gap, provide control and improve efficiency. A review is underway to inventory meter sets affected by the gap and schedule mitigation.

Documentation of atmospheric corrosion during the routine inspection does not necessarily mean an asset integrity issue exists. The routine three-year inspection is a screening process to determine if further engineering evaluation is necessary. PG&E has sampled 45 of the 583 known transmission asset locations and performed a field assessment of each location. Through the field assessment and subsequent engineering evaluation 78% of the sampled locations required no further action based on engineering analysis. The remaining 22% of the sampled locations were confirmed to require some level of remediation and will be risk-ranked for completion based on consequence factors (e.g., population in proximity to the pipeline) and likelihood factors (e.g., the extent of measured corrosion). Zero locations were determined to have a condition requiring an immediate repair.

The remaining 538 field assessments were completed in January 2014 and are pending engineering analysis to determine what, if any, further remediation action is necessary. Any transmission remediation projects resulting from these assessments will be developed, prioritized by risk and completed over the next four years (2014-2017). The field assessment and remediation plan for distribution will be developed once the records inventory is complete.

To prevent this program gap from recurring, PG&E is creating a centralized atmospheric mitigation program within the new Corrosion Services organization that will develop prescriptive procedures, assign accountabilities, and improve processes and controls to ensure that inspection data is communicated and reviewed in a timely manner and locations requiring follow-up are risk ranked and mitigated appropriately.

4. Alternating Current (AC) Interference Coupling, Fault Protection

On December 19, 2012, PG&E provided the CPUC a self-reported non-compliance notification describing non-compliance with 49 CFR §192.467(f) "External corrosion control: Electrical isolation." In this report, PG&E identified a single location where PG&E did not properly protect its gas transmission lines from the risk of an electric fault current from an electric transmission tower in close proximity.

PG&E committed to embarking on a system-wide effort to identify other locations where gas transmission pipeline segments located in close proximity to electrical transmission lines do not have proper protection to guard against fault currents and lightning (also called "coupling"). As part of its corrective action plan, in June 2013, PG&E published a new procedure, TD-4182P-01, "AC Interference: Identifying and Mitigating Against Underground Arcing from Phase-to Ground Faults from Electric Transmission Towers or Poles." This procedure covers site-specific evaluations to identify locations where faults from electric transmission lines may affect gas transmission pipelines and appropriate measures to protect these pipelines against fault currents.

In accordance with the Tier 1 evaluation described in TD-4182P-01, a system-wide review has identified approximately 7,000 locations where there is the possibility of insufficient protection from the threat of AC coupling from a nearby electric transmission lines. From this data, PG&E has begun Tier 2 evaluations, conducting over 550 field assessments. These field assessments have thus far determined that 81% of evaluated locations were in compliance with the required protection criteria, and 19% percent require additional mitigation to provide proper protection based on industry-accepted criteria. The locations requiring further mitigation are being risk-ranked and will be remediated in a timely manner. The remaining approximately 6,450 locations will be field assessed and mitigated as required through a risk-based approach over a 10 year period.

5. Inadequate Cathodic Protection Mitigation

On June 5, 2012, PG&E provided the CPUC with a self-identified non-compliance notification indicating that PG&E did not promptly remediate indications of inadequate cathodic protection (CP) on its transmission pipelines. The initial report identified 180 instances which have all received a field assessment and engineering analysis. To date, 164 locations have been remediated, 10 projects are scheduled for construction and will be completed by August 2014, and the remaining six locations require additional engineering evaluation and testing, which will be completed by the end of 2014.

In addition to these 180 locations, PG&E completed a thorough records inventory and found 490 additional locations with indications of inadequate CP on its transmission system. PG&E has assessed and risk-ranked these 490 locations and plans to complete remediation work for all locations by 2016. PG&E has also identified possible indications of inadequate CP on its distribution system and plans to perform a similar records review of distribution records to ensure all assets are properly protected. Finally, PG&E has implemented a process for centrally tracking and monitoring indications of inadequate CP to ensure they are appropriately mitigated in a timely manner.

6. Reevaluation of Unprotected Steel Pipe

49 CFR §192.465(e) permits pre-1970 distribution pipe to be unprotected provided it is leak surveyed on a 3-year interval. Additionally, federal regulations require an operator to "reevaluate its unprotected pipelines and cathodically protect them…in areas in which active corrosion is found." With regard to the reevaluation requirement, PG&E has identified a gap in its corrosion control standards, which lack guidance for reevaluating unprotected steel in its 3-year leak survey program.

Under PG&E's Distribution Integrity Management Program (DIMP) an elevated external corrosion threat was identified in the San Francisco Division through the risk and threat assessment process. A root cause analysis was performed in September 2013 to determine why San Francisco was experiencing the elevated threat. The final report concluded that San Francisco had pre-1970 unprotected steel pipe with external corrosion leaks that had not been reevaluated to determine where active corrosion was present via electrical survey. Cathodic Protection information is currently being gathered and digitized, in conjunction with PG&E's Pathfinder asset mapping program, to inventory all cathodically unprotected steel pipe in San Francisco.

PG&E will create standards and procedures to address the evaluation and monitoring of unprotected steel pipe. San Francisco Division will evaluate its unprotected steel for inclusion in a Cathodic Protection Area or for replacement. DIMP will continue applying root cause methodology to identify any similar areas of elevated external corrosion threats within PG&E's system.

7. Internal Corrosion

49 CFR §192.475(b) requires the internal surface of pipe to be inspected for internal corrosion any time a pipe is removed. PG&E Design Standard O-16, Section 9 specifies, "…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…." PG&E has discovered that its internal corrosion inspection process may not be consistently understood and practiced. PG&E plans to update the instructions for Form 62-4060 ("A-form") to note and emphasize the internal corrosion inspection requirement. PG&E plans to publish and communicate the new requirement by December 31, 2014.

Furthermore, PG&E is implementing the use of mobile devices to electronically record leak repair and inspection by crew foremen in the field. This software will require certain fields of the A-form, such as internal corrosion inspection of metallic pipe, to be completed in order to close out applicable maintenance activities. System-wide roll-out of the mobile devices and software for leak repair and inspection is anticipated by the end of July 2014.

8. Conclusion

Significant program enhancements are underway as a result of the identified corrosion control program deficiencies described above and PG&E's commitment to build fundamentally sound programs, ensuring public and asset safety and regulatory compliance. As part of PG&E's continuous improvement effort to enhance the safety of our gas system, we will continue to find and address any additional issues related to our corrosion control programs.

SUMMARY CORRECTIVE ACTIONS TABLE

PROGRAM	Action Description	Status/Expected Completion
Atmospheric Corrosion Inspection	Development of a program to address CGIs for maintenance activities (inspection, leak survey & ISSP). Also, additional locations which require remedial atmospheric corrosion inspections as part of the records inventory and other data gathering initiatives.	• CGI Program rollout in 2014 • Additional inspections will be performed as remedial locations are identified. Identify all locations requiring remediation – ongoing
Atmospheric Corrosion Mitigation	Atmospheric corrosion records inventory and documentation review underway. Upon completion PG&E will have the total number of locations which need to be evaluated for further atmospheric corrosion remediation action.	• Records review to be completed for transmission assets by 8/31/2014 and followed by review for distribution assets
Atmospheric Corrosion Mitigation	Field assessment of atmospheric locations with remediation projects completed based on risk.	• Field assessment of all identified 583 transmission spans completed by 1/31/14 • Engineering analysis for all 583 locations to be completed by 3/31/14 • Remediation for transmission – 2014 to 2017 • Field assessment and remediation plan for distribution – date TBD
AC Interference - Coupling	Perform a system-wide review, conduct Tier 2 evaluations and field assessments. Use the information to identify locations requiring further mitigation. The remaining locations will be field assessed and mitigated as required through a risk-based approach.	• Completed system-wide review and conducted 550 field assessments and engineering analysis • Remaining approx. 6,450 locations will be field assessed and mitigated as required through a risk-based approach over a 10 year period
Inadequate Cathodic Protection Mitigation – Distribution	Conduct a thorough records inventory and identify any additional locations with indications of inadequate CP on its distribution system. The locations will be risk ranked and plans will be developed to remediate the locations.	• Process to address distribution low reads will be developed in 2014 • Remediation TBD based on process requirements
Inadequate Cathodic Protection Mitigation – Transmission	Conduct a thorough records inventory and identify any additional locations with indications of inadequate CP on its transmission system. The locations will be risk ranked these and plans developed to remediate the locations.	• As of 12/31/13, 164 locations have been remediated • 10 locations are pending construction • Remaining remediation to be completed by 2016
Unprotected Steel Pipe Mitigation – Distribution	Evaluate the 10 areas of unprotected steel pipe in SF Division; collect and analyze the CP information.	• Continuous evaluation through DIMP
Internal Corrosion Inspections	Update A-form instructions to provide further clarification on internal corrosion inspection requirements when pipe is removed.	• Update relevant procedure by 12/31/2014
Program Enhancements	Continue due diligence to further identify and implement strategies to mitigate corrosion threats to the transmission and distribution system.	• Ongoing