Pacific Gas and Electric Company®

[redacted]

[redacted]
Senior Manager
Regulatory Compliance
Gas Operations

6111 Bollinger Canyon Rd.
4th Floor
San Ramon, CA 94583
[redacted]

Fax [redacted]
Internet [redacted]

February 18, 2014

Mr. Mike Robertson
Gas Safety and Reliability Branch
Safety and Enforcement Division
California Public Utilities Commission
320 West 4th Street, Suite 500
Los Angeles, CA. 90013

Re: State of California – Public Utilities Commission
General Order 112-E PG&E's Transmission Integrity Management Audit

Dear Mr. Robertson:

The Safety and Enforcement Division (SED) conducted a General Order 112-E audit of PG&E's Transmission Integrity Management Program (TIMP) from August 27 through 31, 2012 and from September 10 through 14, 2012, the SED issued its audit report, identifying probable violations and recommendations. PG&E agrees with 7 violations and respectfully disagrees with 1 violation. Attached is PG&E's response, and the the updated information about the steps PG&E has taken to respond to several of the issues identified in the CPUC's audit report. PG&E strives to continuously improve and strengthen its Integrity Management Program, and greatly values the SED's feedback. Please contact [redacted] at [redacted] or [redacted] for any questions you may have regarding this response.

[redacted]

Sincerely,

/S/
[redacted]

Attachments

cc: Banu Acimis, CPUC
Dennis Lee, CPUC
Liza Malashenko, CPUC

Sumeet Singh, PG&E
[redacted], PG&E
[redacted], PG&E

[redacted]

General Order 112-E Findings
CPUC Inspection Report December 17, 2013
Transmission Integrity Management Program

INSPECTION INFORMATION

Inspection Dates	Finding	CPUC Contact	CPUC Phone #
August 27-31, 2012 September 10-14, 2012	NOV-1	Banu Acimis	(916) 928-3826

INSPECTION FINDING

<table>
<tr>
<td>CPUC Finding</td>
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1. <u>Title 49, Code of Federal Regulations (CFR), § 192.905 (b)(1) Identified sites</u>

Title 49, CFR, §192.905(b)(1) requires operators to obtain and consider the information from routine operation and maintenance (O&M) activities along the pipeline to identify newly identified sites.

As described in Section 6.2 of RMP-06, PG&E Risk Management Engineers perform High Consequence Area (HCA) analysis on a system wide basis annually.

In a review of PG&E's process for identification of newly identified HCAs, SED noted that even though PG&E's annual HCA review process defined in Section 6.2 of RMP-06 includes routine O&M activities as one of the data sources reviewed annually, SED did not identify any procedure that PG&E utilizes in order to incorporate data from O&M activities into its TIMP.

Pipeline and Hazardous Materials Safety Administration (PHMSA), frequently asked question (FAQ) 18 of Gas Integrity Management states in part that "An operator is expected to make a reasonable effort to identify sites meeting the criteria for 'identified sites'. The rule requires that operators consider information they glean from routine operations and maintenance activities along the pipeline…"

As a result of the 2010 PG&E TIMP audit, SED documented that PG&E had no process for assuring that the HCA information received from sources outside its Integrity Management (IM) group that PG&E properly tracked, documented and integrated HCA information into its Baseline Assessment Plan (BAP) in a timely fashion.

In its 2010 audit response to the Commission, PG&E listed sources of information gathered from public officials and external sources and mentioned a notification from the Vice President of Engineering informing all gas employees to notify the IM group of potential identified

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	sites. However, during the audit, SED found that PG&E did not have any formal process to gather pipeline information from its other departments related to design, construction, operation and maintenance activities which can help gather data to identify new "identified sites". Therefore, PG&E must do the following: 1. PG&E must establish procedures that document how it incorporates O&M activities in the identification of new HCAs. PG&E must utilize O&M activities such as routine patrols, leak surveys, etc., in addition to satellite imagery and official records to observe changes and evaluate the potential impact on its TIMP and to identify new HCAs. 2. When PG&E identifies new HCAs, it must maintain records that document the date when it identifies a segment of pipeline as an HCA and the method of identification such as routine O&M activities.

PG&E RESPONSE

PG&E agrees with this violation. Moving forward, PG&E will increase its emphasis on utilizing regular patrols as a means of identifying new construction. On December 18, 2013, PG&E published procedure TD-4412P-07, "Patrolling Gas Pipelines" (Attachment A), which provides guidance for field personnel to recognize identified sites, and the process to communicate these findings back to IM to be reviewed for HCA changes. PG&E will continue to review annual parcel data as well as care facility data for land use and detection of identified sites. PG&E will incorporate this data into its enhanced HCA identification process described below.

PG&E has been working to enhance its HCA identification process, and has implemented a new tool, the Compliance Auditor Tool. This tool was implemented in Gas Map 2.0 in 2013 and will be implemented in eGIS in 2014. The tool will compare a pipeline's proximity to new structure layer in eGIS. The structure layer digitizes both building footprints, as well as outdoor public assembly areas, and gathers relevant attribute data such as land use and unit count, to be incorporated into the HCA identification process. PG&E will conduct quality assurance checks on the structure layer using ortho-corrected aerial photography on a periodic basis to ensure the accuracy of the data. PG&E is updating Procedure TD-4127S, "Class Location Determination and Compliance Requirements", which will specify the frequency for updating the structure layer, and the process for utilizing this information to identify HCA changes.

PG&E plans to begin incorporating O&M activities identified through patrolling into the

[redacted]

structure layer by the end of the second quarter in 2014. The structure layer will contain metadata to trace it back to the initial observation (for example, patrol number and date). The Compliance Auditor tool will log and track all changes to HCA's, date of identification, and additional relevant information. Finally, these changes will be posted to eGIS.

ATTACHMENTS

Attachment #	Title or Subject
A	TD-4412P-07, "Patrolling Gas Pipelines"

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
TD-4127S, "Class Location Determination and Compliance Requirements"	06/30/2014		Asset Knowledge Management

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August 27-31, 2012 September 10-14, 2012	NOV-2	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	
	2. <u>Title 49, Code of Federal Regulations (CFR), § 192.905 (c) Newly identified areas.</u> When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified." [Emphasis Added] In accordance with Title 49, CFR, § 192.921(f), and 192.921(g), operators are required to do the following: 1. Continual process of performing information analysis includes steps to promptly identify new HCAs including newly constructed segments and new identified sites that are determined to be covered by this rule 2. Incorporate the new HCA affecting segments into the BAP within one year of identification. 3. Complete the baseline assessment of a newly- installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. PG&E conducts annual and five-year reviews of its transmission pipelines to identify new HCAs. SED reviewed the Contra Costa County 2011 annual county report and audit change logs as well as the most recent five-year complete review of transmission lines to re-verify HCAs in Contra Costa County. SED noted that PG&E uses "date entered" information shown on its BAP as the HCA identification date; however, PG&E's procedures do not define this data type as the date it identifies a new HCA. SED also noted that PG&E did not identify some identified sites in a timely

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	manner, which resulted in a delay in the integration of the relevant data into its BAP within a year as required by Title 49, CFR, §192.905 (c). SED reviewed records and identified newly identified sites which PG&E did not incorporate into its BAP within a year. Below are two examples of identified sites which PG&E added to its BAP on November 24, 2011. 1. HCA DREG4281, [redacted] Restaurant appeared in the September 28, 2008 imagery 2. Kern Route 142S, [redacted] Restaurant also appeared in the September 28, 2008 imagery SED also found some newly identified HCAs from new transmission pipeline installations that PG&E did not integrate into its BAP within one year from the date it identified the areas. For example, PG&E installed transmission line L-191, Segments 133-144 in May 2009 which became operational in November 2009. According to PG&E representatives, the IM group became aware of the newly installed pipeline when it was entered into PG&E's Geographic Information System (GIS) on November 24, 2011. Even though the HCA existed since the start of operation of L-191, Segments 133-144, in November 2009, PG&E did not incorporate this information until November of 2011. SED determined that PG&E's IM group relies entirely on the information entered into GIS which may potentially delay not only the identification of new HCAs but also the integration of the new HCAs into PG&E's BAP in a timely manner. SED concluded that PG&E's IM group does not have a documented process of gathering data on the new pipe installations from PG&E's other transmission pipeline groups such as design and engineering. If PG&E uses GIS as its communication tool between its various pipeline divisions for new construction or physical changes observed in the field, then it must require its divisions to provide timely notification of changes to the GIS group and must establish specific timeframes for such notification. To summarize, SED reviewed several newly identified HCAs and noted that

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	PG&E's process of updating its BAP to reflect the impact of newly-identified HCAs has the following deficiencies: 1. Annual and Five-year HCA Review: SED noted that PG&E used the "date entered" date as the identification of a new HCA; however, PG&E does not define this data field in its procedures. 2. Audit Change Logs: SED reviewed 2011 audit change logs for Contra Costa County and noted several examples of identified sites which PG&E identified in 2011 that existed a couple of years prior to its identification of the HCAs. PG&E should have discovered these identified sites and integrated them into its BAP prior to 2011. 3. New Transmission Pipelines: SED also found that PG&E did not enter into its BAP some new transmission pipeline information within a year. SED concluded that PG&E is relying on GIS data to gather relevant data to update its program and does not have effective communication with its design, construction, operation, maintenance, and testing departments. Therefore, PG&E must do the following: 1. PG&E must clearly define in its procedures the date it establishes as the "HCA identification date" to ensure that newly identified covered segments are included in its BAP within a year. 2. PG&E must improve its process of compiling and managing data from different sources and update its HCA list in a timely manner (i.e., [redacted] and [redacted] Restaurants). To do this, PG&E must establish an effective process to communicate with its transmission pipeline design, construction, operations, maintenance, and testing departments to obtain the knowledge about new identified sites in order to identify new HCA segments and to update its BAP within one year of identification. 3. PG&E must obtain the information on its newly installed pipe from the design and construction groups and integrate the information into its TIMP in a timely manner in order to identify and analyze changes to its transmission system and incorporate new HCAs into its BAP within one year of identification.

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PG&E RESPONSE

PG&E agrees with this violation and has implemented three measures to address this finding.

PG&E has enhanced its HCA identification process, which will be updated periodically, and ensure the annual updates to the assessment plan integrate the most up to date information about PG&E's pipelines. Details about the HCA and CL Determination Process can be found in PG&E's response to NOV#1.

Additionally, PG&E published TD-4412P-07,"Patrolling Gas Pipelines", on December 18, 2013, which provides guidance for field personnel to recognize identified sites, and the process to communicate these findings back to IM to be reviewed for HCA identification (Attachment A). This will ensure any field observations get incorporated into to periodic updates of structure layer.

PG&E has also been aggressively working to reduce the timeframe to map transmission projects. In 2013, PG&E established a company goal to map all gas transmission jobs within 90 days from job completion. PG&E is committed to ensuring records are updated promptly to accurately reflect transmission pipe and pipe facilities.

PG&E Gas Transmission Mapping Group plans to implement a work-in-progress layer, by the end of the second quarter in 2014, which will allow PG&E to proactively review proposed projects and incorporate this information and identify HCA's as part of the annual BAP review.

PG&E is updating Procedure TD-4127S, "Class Location Determination and Compliance Requirements", to provide specifics for this data integration, and to clearly define how PG&E establishes the HCA Identification Date. PG&E's response to NOV#1 provides additional details regarding how this data will be incorporated into the HCA identification process. PG&E will use the SAP scheduling tool to ensure all new HCA's are scheduled for assessment in accordance with § 192.905 (c) Newly identified areas.

ATTACHMENTS

Attachment #	Title or Subject
A	TD-4412P-07, "Patrolling Gas Pipelines"

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
TD-4127S, "Class Location Determination and Compliance Requirements"	06/30/2014		Asset Knowledge Management

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INSPECTION INFORMATION

Inspection Dates	Finding	CPUC Contact	CPUC Phone #
August 27-31, 2012 September 10-14, 2012	NOV-3.1	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	
	3. <u>Title 49, Code of Federal Regulations (CFR), § 192.911 What are the elements of an integrity management program?</u> 1 . The PG&E IM group becomes aware of new pipe installations after the information is entered into GIS as illustrated in RMP-06, Figure B-9: Management of Change - Physical. If PG&E uses GIS as the main data source for the IM group, then PG&E needs to emphasize the importance of keeping the GIS information current (i.e. requiring new information to be entered within a specific timeframe). PG&E must have a procedure that ensures timely communication to the IM group for newly installed pipeline to minimize delays in identifying HCAs. PG&E should also seek to find effective ways to utilize information from its O&M activities that could affect the identification of HCAs such as the construction of apparent identified sites in proximity to a transmission pipeline, verification of possible identified sites unclear in aerial photography using field personnel, and corrections to erroneous pipeline center data submitted by local mark and locate personnel. PG&E must verify the knowledge of local field personnel about IM and HCAs and if necessary train local division and district personnel to recognize any changes or corrections that PG&E needs to communicate to the IM group. Therefore, as required by Title 49, CFR § 192.911(k), PG&E must develop formal management of change procedures to integrate new information from its routine O&M activities in order to identify newly identified HCAs. Additionally, PG&E's construction department must provide new pipeline installation information to the IM group in order to identify newly constructed pipelines that may be in HCAs.

PG&E RESPONSE

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PG&E agrees with this violation and published TD-4412P-07,"Patrolling Gas Pipelines", on December 18, 2013, which provides guidance for field personnel to recognize identified sites, and the process to communicate these findings back to IM to be reviewed for HCA identification (Attachment A).

PG&E is also updating procedureTD-4127, "Class Location Determination and Compliance Requirements", which will outline how PG&E's evaluates any new information identified in the field, and incorporates these findings into PG&E's HCA identification process. PG&E's response to NOV#1 provides additional details regarding how this data will be incorporated into the HCA and Class location determination.

ATTACHMENTS

Attachment #	Title or Subject
A	TD-4412P-07, "Patrolling Gas Pipelines"

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
TD-4127S, "Class Location Determination and Compliance Requirements"	06/30/2014		Asset Knowledge Management

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August 27-31, 2012 September 10-14, 2012	NOV-3.2	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	**4. <u>Title 49, Code of Federal Regulations (CFR), § 192.911 What are the elements of an integrity management program?</u>** 2. In addition, ASME B31.8S, Section 11, Management of Change Plan states in part "(g) System changes, particularly in equipment, may require qualification of personnel for the correct operation of the new equipment. In addition, refresher training should be provided to ensure that facility personnel understand and adhere to the facility's current operating procedures." SED noted that PG&E's Management of Change (MOC) procedure does not reference a requirement to determine if an equipment change would necessitate additional training and qualification of its personnel to ensure the correct operation of new equipment. Therefore, as required by Title 49 CFR § 192.911(k), PG&E must have a procedure on how equipment changes are evaluated and implemented. PG&E must add a requirement to its MOC procedure to provide necessary additional training to qualify its employees to correctly operate the new equipment prior to the equipment becoming operational.

PG&E RESPONSE

PG&E agrees with this violation. Currently, RMP-06, Section 16, does not reference a requirement to determine if an equipment change would necessitate additional training and qualification of personnel to ensure the correct operation of new equipment. However, PG&E does have another procedure, TD-4001P-04 "Gas Product and Supplier Approval", section 4 and 5, (Attachment B) that adequately addresses this finding. PG&E will include a reference to TD-4001P-04 in the MOC procedure in the next revision of RMP-06.

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ATTACHMENTS

Attachment #	Title or Subject
B	TD-4001P-04 "Gas Product and Supplier Approval"

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-06	6/30/2014		Risk Management

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August 27-31, 2012 September 10-14, 2012	NOV-4.1	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding

4. <u>Title 49, Code of Federal Regulations (CFR), § 192. 925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?</u>

1. Title 49, CFR, §192.925(b)(1)(ii) states in part "…the plan's procedures for preassessment must include…The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA region.".

   PG&E provides in Table 5-3 of RMP-09 the ECDA tool selection matrix consisting of five inspection tools, close interval survey (CIS), direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), electromagnetic pipeline current mapper (PCM), and ultrasonic testing (UT) Guided Wave and 16 different piping conditions and the environment surrounding the pipeline. In Table 5-4 of RMP-09 PG&E provides guidance on indirect inspection and complementary tool selection. The indirect inspection tools (IITs) are selected based on the data collected in the preassessment step of the ECDA process. PG&E records both primary and complementary IITs on its Form D. However, SED noted that PG&E does not document the basis for selecting such tools on Form D or in any other of its records.

   In Section 5.7.3 of RMP-09, PG&E only requires documenting selected IITs but not the basis for choosing such tools. SED did not find any PG&E procedures or records documenting the basis for the tools selected for the ECDA process.

   Therefore, PG&E must establish procedures for documenting the basis for selecting IITs and keep records accordingly in order to justify the effectiveness of the selected tools for the region that PG&E will utilize the IITs in.

   SED also noted that Table 5-1 of RMP-09, Preassessment Data List shows that the depth of cover information is not required information for selecting the IITs for the ECDA process. PG&E explained that it gathers

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	pipeline depth information as a part of its indirect inspection phase. SED determined that PG&E must have the depth of cover data prior to selecting the appropriate IITs during the preassessment step since the depth of cover may restrict the use of some indirect inspection techniques and IITs.

PG&E RESPONSE

PG&E agrees with this violation, and will revise RMP-09 to require adequate documentation for the basis of indirect inspection tool selection on Form D.

It should be noted that though PG&E does not currently document the basis for its IIT tool selection, PG&E continues to evaluate the effectiveness of indirect inspection tools as well as the quality of the ECDA data gathered, and documents these findings in the ECDA Effectiveness Study Report. The effectiveness of the tools is evaluated by statistically comparing the actual pipe conditions discovered in direct examination against the indication severity from indirect inspection survey. Furthermore, PG&E's tool selection matrix in Table 2 aligns with NACE ECDA Standard Practice SP0502-2008, and with PG&E ECDA tool selection matrix in Table 5-3 and Tool Selection Guide in Table 5-4 of RMP-09. As stated above, in addition to documenting the IIT tool selection, Form D will be revised to include the basis for this selection.

PG&E agrees with the CPUC that depth information can play a significant role in tool selection. However, PG&E respectfully disagrees with the CPUC's finding that PG&E does not use available depth data when selecting IIT's. PG&E is working to ensure a more comprehensive records review is completed, and all available depth data is utilized to select the appropriate tools. The response to NOV 4.2 provides additional information about PG&E's enhanced process for gathering depth data, incorporating that information into IM, and mitigating conditions warranting actions as necessary.

Though PG&E considers this data as part of IIT Tool Selection, PG&E does not specify that this data is required in Table 5-1 of RMP-09. PG&E will update Table 5-1 and stipulate that pipe depth information is "required" data, to ensure records are reviewed in a consistent and comprehensive manner, prior to selecting IIT Tools.

The pipe depth is confirmed during initial indirect inspection work. IIT selection is adjusted if the pipe depths differ significantly as to impact IIT effectiveness. In this event another technology is applied. PG&E integrates pipe depth information to confirm that the correct inspection tool is selected. PG&E also adjusts tool selection during the indirect inspection survey after pipe depth information is available, or even changes the assessment tool from ECDA to in-line inspection or pressure test, whichever is appropriate per RMP-06.

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ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-09	6/30/2014		Risk Management

[redacted]

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INSPECTION FINDING

<table>
<tr><td>CPUC Finding</td><td>

4. <u>Title 49, Code of Federal Regulations (CFR), § 192. 925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?</u>

2. SED noted that PG&E must provide additional specificity to its procedural documentation describing how an ECDA that finds indications of third party damage (TPD) will meet regulatory requirements in Title 49, CFR §§ 192.925(b) and 192.917(e)(1).

SED found that Section 6.6.1 of RMP-09 does not adequately cover the code requirements. Title 49, CFR, §192.917 (e)(1), Third Party Damage states in part "…If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures…"

SED reviewed the L-132 ECDA assessment and noted that PG&E found mechanical damage on the pipeline at one of the excavation sites. SED also reviewed PG&E's Long Term Integrity Management Plan (LTIMP). Additional mitigation items in the LTIMP stated "In order to decrease the likelihood of impact from third party damage activities, it is recommended that PG&E verify the depth of cover at the locations indicated on the TPD tab and determine if remediation is needed (Mit #7)." The LTIMP also indicated that one of the segments of L-132 that was exposed had a considerable history of TPD and that PG&E confirmed and communicated the depth of cover to its Risk Management Team without a commitment to perform any "work" to reduce the risk.

SED noted that the intent of the LTIMP was to "… Develop a plan to remediate, and monitor the pipeline in the interim…" SED found a disconnect between what was desired for the single preventive measure for TPD and the action PG&E has yet to propose over five years after its Direct Assessment program was completed and 19 months before its

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[redacted]

	next ECDA assessment must be completed. SED determined that if PG&E implements a preventive measure in the future, the LTIMP should provide the acquisition of data for the Nseg which PG&E defines as a 'numbered' transmission line with a portion of the pipeline identified for assessment using ECDA and consists of one or more ECDA Regions. LTIMP should also provide information regarding whether the implemented measure is performed effectively or more information should be augmented to achieve the desired results. However, PG&E has not taken action. PG&E must complete the depth of cover verification activities in order to implement preventive measures prior to the initiation of the reassessment. SED also noted that since PG&E has such long lag times in completing LTIMPs, it is probable that this issue exists on many of the segments assessed using ECDA where TPD is a threat.

PG&E RESPONSE

PG&E agrees with this violation and that in the case of L-132, though third party damage and reduced cover were incorporated into the LTIMP, specific mitigation actions did not occur prior to the CPUC audit. PG&E has recently updated its reduced cover procedure, TD-480-13P-01, and is estimated to be published by the end of the first quarter of 2014. The document outlines the process for identifying, investigating and as warranted, remediating these locations in a timely manner. The process also clearly establishes a method for communicating depth data identified in the field to IM to be reviewed and scheduled for mitigation. PG&E will update RMP-09 to apply TD-480-13P-01 when locations with reduced cover are identified.

Additionally PG&E is developing decision trees, which will be incorporated into RMP-17, to provide guidance for these preventive and mitigative (P&M) measures and their effectiveness. Details regarding this process can be found under the response to NOV-5.

Personnel working on integrity management will use available depth data, and utilize the depth data identified through the pipeline centerline survey conducted over all transmission pipelines in 2013 to schedule examinations. These locations will be risk ranked and scheduled for work accordingly.

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ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-09	6/30/2014		Risk Management
Provide TD-480-13P-01	3/31/2014		Risk Management

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INSPECTION FINDING

CPUC Finding	**4. <u>Title 49, Code of Federal Regulations (CFR), § 192. 925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?</u>** 3. Title 49, CFR §192.925 (b)(2)(i) states in part "...the plan's procedures for indirect examination of the ECDA regions must include – (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;" PG&E does not consider an ECDA on a covered section of pipe as a "first time ECDA" if an ECDA had been performed on a different covered section of the pipe in the past for some of the routes within the same Nseg. For example, Nseg 220_2010 had six routes, two of which PG&E reassessed. PG&E performed only two excavations (one direct examination and one effectiveness dig) for the other four routes which covered a total of approximately 1.1 miles of pipeline. PG&E must establish provisions for applying more restrictive criteria for covered segments when conducting the ECDA indirect examination step for the first time on a segment. If the first time indirect examination of certain covered segments did not have more restrictive criteria applied at the time of that examination, PG&E must apply more restrictive criteria during the reassessment to meet the intent of Title 49, CFR, §192.925 (b)(2)(i).

PG&E RESPONSE

PG&E acknowledges that additional specificity should be added to RMP-09 to clarify the more restrictive criteria being applied for first time assessment, and will update RMP-09 accordingly. Though additional documentation is required to provide clarity, PG&E has

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been implementing more restrictive criteria for first time assessments, and respectfully disagrees with this violation The more restrictive criteria PG&E applies are listed below. It should be noted that these measures were also applied to NSeg 220_2010:

Pre-assessment
PG&E gathers any available CP records to be incorporated in the pre-assessment phase. PG&E also conducts pre-assessment meetings to interview key employees, such as the responsible pipeline engineers, corrosion engineers, corrosion mechanics, and field engineers, and incorporates their SME knowledge into the decision making process for ECDA tool selection.

PG&E also conservatively elects to use all three indirect inspection tools specified by NACE SP0502-2008.

Indirect Inspection
PG&E's project engineer defines use of spot-checking, repeating indirect inspections, or other verification means to ensure consistent data are obtained per NACE SP0502-2008 Section 4.2.2.2. These additional verification methods are applied where survey readings differ significantly from the baseline value in the survey.

Direct Examination
PG&E performs additional testing such as magnetic particle testing, X-Ray photography, and Ultrasonic Testing, as specified in Section 7.12 of RMP-09.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-09	6/30/2014		Risk Management

[redacted]

General Order 112-E Findings
CPUC Inspection Report December 17, 2013
Transmission Integrity Management Program

INSPECTION INFORMATION

Inspection Dates	Finding	CPUC Contact	CPUC Phone #
August 27-31, 2012 September 10-14, 2012	NOV-4.4	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding

4. Title 49, Code of Federal Regulations (CFR), § 192. 925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

4. Section 8.2.2 Corrosion Rate of RMP-09, Estimated corrosion rates per soil resistivity states: "Other corrosion rates that are scientifically supported may also be used, as described in the paper 'Commentary on Soil Corrosion and Estimates for Pit Growth Rates', dated 01/05/2009."

SED noted that PG&E takes an exception to allow a corrosion growth rate of "1 mil/year" based on a Mears Group report, titled "PG&E Commentary on Soil Corrosion and Estimates for Pit Growth Rates", dated 01/05/2009. The report conclusions are based on an effective cathodic protection system in that a well coated pipeline could expect to have almost no corrosion with a corrosion growth rate of "1 mil/year."

SED noted that since PG&E did not define what PG&E's criteria are for an effective cathodically protected pipeline system, the application of this report to PG&E's pipeline systems is questionable. SED also determined that the use of 1 mil/year corrosion rate on PG&E's Line 300A South for an ECDA integrity assessment was not appropriate.

Table B1 of ASME B31.8S lists corrosion growth rates related to soil resistivity:

- 3 mils/ year for Soil Resistivity, >15 000 ohm–cm and no active corrosion
- 6 mils/ year for Soil Resistivity, 1 000 -15 000 ohm–cm and/or active corrosion
- 12 mils/ year for Soil Resistivity, < 1 000 ohm–cm (worst case)

The National Association of Corrosion Engineers (NACE) SP 0502-2008 D3.2 states in part "When other data are not available, a pitting rate of 0.4 mm/y (16 mpy) is recommended for determining re-inspection intervals…" and D3.3 states "The corrosion rate in Paragraph D3.2 may be

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	reduced by a maximum of 24% provided it can be demonstrated that the CP level of all pipelines or segments being evaluated have had at least 40 mV of polarization (considering IR drop) for a significant fraction of the time since installation." For the purposes of ECDA, as required by Title 49, CFR, §192.925 (b), the corrosion growth rates included in NACE SP 0502-2008 are the only ones that may be used in lieu of actual values. PG&E may not choose corrosion rates from one report and apply them to a "process" while disregarding the requirements of the applicable standard.

PG&E RESPONSE

PG&E values the CPUC's opinion and will incorporate the CPUC's recommendation to remove the white paper, "PG&E Commentary on Soil Corrosion and Estimates for Pit Growth Rates, dated 01/05/2009", as an acceptable guidance document. Though this document is referenced in RMP-09, PG&E respectfully disagrees with this violation since PG&E applies corrosion growth rates that are in accordance with Federal Code, which allows the use of measured corrosion growth rates.

PG&E's practice is to use the measured/calculated corrosion growth rates for remaining life calculation. If these values are not available, PG&E estimates the corrosion growth rate based on measured soil resistivity that is obtained at all ECDA excavations, provided in Appendix C of NACE SP0502-2008 and Table 1 in ASME B31.8S-2004.

The CPUC references corrosion rates in of NACE SP 0502 - 2008 as the only acceptable corrosion growth rates. However, 49 CFR 192.925(b) also refers to and incorporates by reference ASME B31.8S, section 6, which pertains to direct assessment and that section refers to Appendix B which includes a table of corrosion rate values (Table B1) that may be used when soil resistivity is known. Section D3 in the referenced NACE SP states that this corrosion rate should only be applied for bare steel, and if no cathodic protection is available. This section does not apply to PG&E's system as all of PG&E's transmission pipelines should have CP applied.

PG&E believes that applying Table B1 from ASME B31.8S captures the intent of the code, and is also incorporated by reference in NACE SP0502-2008 for determining corrosion growth rates.

As stated above, PG&E agrees that the white paper, "PG&E Commentary on Soil Corrosion and Estimates for Pit Growth Rates, dated 01/05/2009"; requires that a number of specific criteria to be met in order to be applicable. Since PG&E has not applied this white paper in recent years, PG&E will update RMP-09 and remove the white paper as an acceptable

guidance document for determining corrosion growth rates.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-09	6/30/2014		Risk Management

[redacted]

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INSPECTION INFORMATION

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August 27-31, 2012 September 10-14, 2012	NOV-4.5	Banu Acimis	(916) 928-3826

INSPECTION FINDING

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4. <u>**Title 49, Code of Federal Regulations (CFR), § 192. 925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?**</u>

5. Title 49, CFR §192.925(b)(3) Direct examination states in part "..(3) Direct examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502-2008, section 5, the plan's procedures for direct examination of indications from the indirect examination must include -

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment…"

Section 5.9.1.2 of NACE RP0502-2002 states "When ECDA is applied for the first time, the pipeline operator should not downgrade any indications that were originally placed in the immediate or scheduled priority category to a lower priority category."

Section 5.2 Prioritization of NACE RP0502-2002 states in part:

"5.2.1 The pipeline operator shall establish criteria for prioritizing the need for direct examination of each indication found during the Indirect Inspection Step.

5.2.1.1 Prioritization, as used in this standard, is the process of estimating the need for direct examination of each indication based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion."

SED noted that for the first time ECDA, PG&E reclassifies some of the immediate indications found as a result of indirect assessment based on some of its direct examinations. The NACE standard states that all immediate indications should be excavated if found as a result of indirect

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	examination when ECDA is applied for the first time. If it is a first time ECDA, PG&E cannot use a sample of the immediate indications as a basis for reclassifying all the remaining immediate indications without conducting a direct examination of all identified immediate indications. PG&E must directly examine all immediate indications found as a result of indirect assessment for the first time ECDA unless PG&E has a documented technical justification for not implementing the NACE recommendation.

PG&E RESPONSE

As discussed by Sumeet Singh and Mike Robertson on Friday, February 14, 2014, PG&E agrees with this violation, and will revise RMP-09 to require direct examinations of all immediate indications identified as part of performing the first time ECDA. Historically, PG&E has applied the "adjacent indications" methodology as outlined in Section 7.3.1 of RMP-09, and grouped immediate adjacent indications. Within these groups, PG&E excavated the most severe indication, and then applied these results to reclassify the group.

Moving forward, PG&E will no longer group immediate adjacent indications. For first time assessments, PG&E will treat each immediate indication uniquely, and perform direct examinations accordingly. PG&E will undertake an effort to review historical locations where immediate adjacent indications have been grouped, and use a risk based approach to evaluate these locations, and take any necessary actions.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-09	6/30/2014		Risk Management

INSPECTION INFORMATION

Inspection Dates	Finding	CPUC Contact	CPUC Phone #
August 27-31, 2012 September 10-14, 2012	NOV-5	Banu Acimis	(916) 928-3826

INSPECTION FINDING

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CPUC Finding

5. **<u>Title 49, Code of Federal Regulations (CFR), § 192.935 What addition preventative and mitigative measures must an operator take?</u>**

   1. SED reviewed several LTIMP reports and found that PG&E did not generate many of them in a timely manner.

      For example, PG&E did not create the LTIMP for L-109-2003 until 2009. Since PG&E conducted the baseline assessment for this project in 2003, it was due for a reassessment in 2010. In fact, the LTIMP for this project established the reassessment interval to be five years since some segments were operating at greater than 50% SMYS. SED also noted that since PG&E generated the LTIMP for L-109-2003 six years after it performed its assessment, PG&E completed re-assessments of some of the segments of L-109 before it addressed all of the mitigative and preventive measures that it identified in the LTIMP.

      Additionally, PG&E identified in the LTIMP one high priority P&M measure affecting four stations. One of the stations had a monitoring point installed, but there were no records available for review during the audit indicating how PG&E addressed the other stations. The other two lower priority P&M measures which involved inadequate cathodic protection (CP) levels had no records indicating that PG&E engaged in corrective action to address the non-compliance. PG&E representatives indicated that these would be included in the next self-report notification update.

      SED noted that since PG&E did not create the LTIMP reports in a timely manner after it completed the assessments, PG&E might have not addressed and promptly communicated to the responsible work groups some P&M measures for implementation.

      Section 9.2 of RMP-17 requires that if PG&E cannot complete the work within the given time frame, the Project Lead shall provide justification for the extension and ensure the integrity of the pipeline will not be compromised.

      PG&E created the LTIMP for L-109-2003 six years after the assessment was completed. During the audit, SED also discovered that the work was not competed. SED did not find any documentation for why PG&E generated the LTIMP for L-109-2003 six years after the assessment and why it did not complete the LTIMP work.

PG&E should have created the LTIMP for L-109-2003 soon after it completed its baseline assessment to identify any additional P&M measures. PG&E should also have implemented necessary P&M measures for the segments or justified the delay in the process of implementing remedial actions.

During the audit, PG&E provided a copy of its LTIMP summary report which shows all pending LTIMP reports along with P&M work activity measures identified as a result of integrity management assessments.

As can be seen from Table 1, as of September 2012, PG&E had a total of approximately 610 pending LTIMP projects. PG&E categorized approximately one third of these (229) as Priority 1 projects. This summary report also indicated that PG&E generated more than one third of all its pending LTIMP projects (258) for the assessments conducted prior to 2006 and based approximately 50% (116) of the pending Priority 1 projects on the inspections it conducted prior to 2006.

Table 1- PG&E's Pending LTIMP Projects

Year	Priority 1	Priority 2	Priority 3	Total
2002	1	-	9	10
2003	7	-	10	17
2004	33	-	41	74
2005	75	68	14	157
2006-2007	109	38	189	336
2008	3	-	12	15
2011	1	-	-	1
Total	229	106	275	610

SED noted that as of September 2012, PG&E has only completed 17% of LTIMPs based on its 2004 baseline assessment mileage. It appears that since PG&E generated LTIMPs several years after the completion of integrity assessments, by the time PG&E started implementing the P&M measures, in some cases, covered segments were due for a reassessment.

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	SED determined that PG&E RMP-17 neither specifies any timeframe to create an LTIMP after PG&E completes an assessment nor does it require an allowed time interval to complete the implementation of P&M measures. Therefore, PG&E must establish provisions in its RMP-17 for not only creating LTIMP reports but also implementing P&M measures with specific timeframes after conducting integrity assessments. 2. SED also determined that PG&E does not have an effective method of providing the Risk Management group with the results of the LTIMPs. For example, if an LTIMP discovery indicates a shallow depth pipe, it may increase the likelihood of a TPD risk score for the particular covered segment. Therefore, PG&E must provide the knowledge learned from LTIMP analysis to the other IM groups not only to revise the associated risk factors but also recalculate the reassessment interval of covered segment accurately if necessary. On July 24, 2012, PG&E submitted a self-identified non-compliance issue to the Commission involving a missed seven-year integrity reassessment for covered segments on a transmission pipeline in Yolo County which was a violation of Title 49, CFR, § 192.939 (a). PG&E scheduled an integrity reassessment of approximately 5.22 miles of four covered segments on Line 172A by May 24, 2012; however, PG&E failed to conduct the reassessments by the due date. PG&E's analysis determined that it would complete the reassessment work for the four covered segments by August 31, 2012. PG&E must clear its LTIMP backlog and establish procedures for implementing its LTIMP process in a timely manner. SED has concluded that PG&E must do the following: ➢ PG&E must initiate the LTIMP process immediately after it completes the assessments to ensure timely implementation of P&M measures. ➢ PG&E must prioritize the P&M measures and schedule the highest priority ones for implementation promptly for each assessed segment and record them in the database. ➢ PG&E's IM group must improve its communication with PG&E's other departments in order to take remedial actions in a timely

	manner. ➢ PG&E must improve its LTIMP database to track the progress of projects and completed work and to update the status of each project. ➢ PG&E's LTIMP team must provide documentation for project time extensions in order to justify the need for the extension and to ensure that it would not affect the integrity of the pipeline adversely.

PG&E RESPONSE

PG&E agrees with the SED finding and recognizes that many of the Post Integrity Assessment Reports (formerly known as LTIMP reports) were not created in a timely manner after the completion of an integrity assessment and may have not promptly addressed and implemented identified P&M measures. Furthermore, there were no provisions in RMP-17 to establish timeframes for completing the Post Assessment Reports and to implement P&M measures. Currently RMP-17 is the process of being revised and is currently scheduled to be completed before July 1, 2014. The new revision will incorporate the following:

- Timeframes to complete the Post Integrity Assessment Reports and to identify any additional P&M once an integrity assessment is complete. PG&E is currently suggesting no later than 180 days to complete both tasks once all the information that is required from the integrity assessment is received.

- Process flows to show how the P&M is to be identified based on threat level changes and increased risk, assigned using a work management database that is available to the different responsible work groups, prioritized based on the risk score, and monitored from inception to completion.

- Established provisions within the procedure in the event that a project cannot be completed in a timely manner and a time extension is needed. Documentation will be provided to ensure that this time extension will not affect the integrity of the pipeline.

- Process flow that will show how the information discovered through the Post Integrity Assessment Report will be communicated to risk management to update the risk score associated with that pipeline segment.

During the 2012 audit, PG&E verbally communicated to the SED that the back log of Post Integrity Assessment Reports would be completed by the end of September 2013. This objective was not accomplished since a majority of the 2013 year was used to improve our Continual Evaluation (CE) process to align with §192.937(b). Furthermore, RMP-17

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revisions were started to provide detail and guidance on how the new process will be implemented. This process outlines how PG&E will implement periodic continual evaluations for the annual Baseline Assessment, following an integrity assessment (and documented in a post Integrity Assessment Report), or as a result of an event that could potentially change the re-assessment method, re-assessment interval, or require additional P&M.

PG&E is drafting these changes and the new CE process has not yet been implemented. Although the CE process was revamped to make the program better, it prohibited PG&E from completing the reports in a timely manner.

In the 2012 Audit Letter, the CPUC references outstanding Post Integrity Assessment Reports (LTIMP Reports). PG&E has developed a plan to complete 50% of the Post Integrity Assessment Reports by the end of April 2014, and complete the remaining reports by the end of 2014. This aggressive schedule was determined by prioritizing the assessments first by the greatest total risk score and then by associated routes.

Additionally, PG&E will work with industry experts, Kiefner and Associates, to build a robust program that identifies P&M measures, and provide guidelines for how to measure the effectiveness of these measures. PG&E is developing a consistent and comprehensive way to monitor these P&M measures. PG&E will conduct a risk based evaluation for outstanding mitigation items, and incorporate completed P&M activities into the overall risk calculation for a given segment.

Several of these items have been incorporated and prioritized in existing maintenance and corrective programs within Corrosion Engineering. The TIMP group is working with Corrosion Engineering to ensure that all P&M measures identified through the Continual Evaluation process are traceable.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Complete 50% of Integrity Assessment Reports	4/30/2014		Risk Management
Complete remaining 50% of Integrity Assessment Reports	12/31/2014		Risk Management

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Update RMP-17	6/30/2014		Risk Management

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INSPECTION INFORMATION

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August 27-31, 2012 September 10-14, 2012	NOV-6	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	**6. <u>Title 49, Code of Federal Regulations (CFR), § 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?</u>** SED did not find any documentation to verify that PG&E has performed continual evaluation for establishing reassessment methods and schedules by considering all information relevant and required to determining risk associated with pipeline operations in HCAs as required by CFR, §192.937(b). SED noted, at the time of the audit that PG&E recently developed a Continual Evaluation Form; however, PG&E had not implemented the form for usage. PG&E must consider the same set of data on a periodic basis and analyze changes and trends that would indicate the need for additional integrity assessments. Additionally, SED determined that PG&E does not base prioritization of P&M measures identified in its LTIMP on risk factors, but on upcoming reassessment intervals. PG&E must prioritize and implement P&M measures identified in the LTIMPs based on their risk score and complete all remedial actions before the next reassessment of the covered segments. On June 5, 2012, PG&E notified the Commission about self-identified non-compliances involving inadequate CP levels which it did not promptly address on transmission pipelines in its system. During the audit, SED reviewed the list of non-compliances and noted that 87 out of 180 locations in PG&E's current LTIMP reports as pending Priority 1 cases to be mitigated in order to resolve the CP level deficiencies. SED determined that there is a disconnect between the district CP personnel, corrosion department, LTIMP teams, and ECDA Teams that has resulted in a delay in the implementation of P&M measures for certain CP systems. PG&E must improve its procedure for continual evaluation in Section 7 of

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RMP-17, by providing additional specificity to improve the clarity and repeatability of the process. Additionally, PG&E must improve the procedure by adding robustness and missing pieces of information to meet the requirements of CFR, §192.937(b).

During the audit, it was unclear to SED what events and data PG&E needed to complete its "Continual Evaluation Form". PG&E needs to clearly define in its procedures that process for filling-out this form.

PG&E must also expand RMP-17, Section 7.2, Data Integration, since this subject is not adequately addressed in either RMP-17 or the Continual Evaluation Form to meet the requirements of CFR, §192.917(a) and (b).

PG&E must also include a review of Risk Assessment Information in the process to meet the requirements of CFR, §192.917(c).

PG&E RESPONSE

PG&E agrees with the SED finding that the continual evaluation section in RMP-17 does not provide enough specificity to improve the clarity and repeatability of the process. Nor does it provide information regarding the data sources and events needed to fill out the "Continual Evaluation Form", as well as failure to fully meet the requirements of §192.917. Revisions to RMP-17 are being drafted and are pending implementation, as stated in NOV #5. The revisions will address the following items:

- Data sources to be reviewed for each of the events that can trigger the Continual Evaluation process.

- Process to fill out the "Continual Evaluation Form" that will incorporate the threat identification performed by risk management and any changes that may have come about due to the event, a list of the data sources used to evaluate the integrity of the pipeline for the Continual Evaluation event, and adjustments to the risk score based on what was discovered.

- Timeframes for completing the Continual Evaluation Form and assigning P&M measures

  As stated in NOV-5, the CE process will establish timeframes for completing the evaluation, assigning measures, documenting the review and basis for these measures, and ensuring the measures are implemented in a timely fashion.

The CE will be subject to the same P&M measures review and Communication Plan

identified in NOV-5.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-17	6-30-2014		Risk Management

[redacted]

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INSPECTION INFORMATION

Inspection Dates	Finding	CPUC Contact	CPUC Phone #
August 27-31, 2012 September 10-14, 2012	NOV-7.1	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	**7. <u>Title 49, Code of Federal Regulations (CFR), § 192.907 What must an operator do to implement this subpart?</u>** 1. SED noted that PG&E does not have a Quality Control (QC) Plan which meets all the requirements of ASME B31.8S-2004, Section 12. PG&E's procedure RMP-06, Section 17, Quality Assurance (QA) outlines its QA plan that verifies the implementation and effectiveness of its TIMP. Section 17.1, Quality Assurance Process states: "The Company implements systematic activities within a quality process to ensure that the IMP effectively addresses pipeline system integrity issues. Such QA assurance activities include periodic analysis of resulting data to promote continual performance improvement and regular monitoring of the Program's implementation to monitor efficiencies." The requirements of ASME B31.8S-2004, Section 12 are different than what PG&E describes in Section 17 of RMP-06. The QC activities in RMP-06 aim to identify deficiencies in the actions taken based on a reactive process. On the other hand, QA activities in ASME B31.8S-2004 focus on evaluating integrity management program effectiveness and assessing program efficiency which is a proactive approach. PG&E must have a QC plan in its TIMP which meets the requirements of ASME B31.8S-2004, Section 12.1 to ensure that the quality control of the actions it performs in assessing the integrity of its pipelines is done properly and that it successfully implements the results of such assessments. The QC plan must also contain all the necessary elements listed under ASME B31.8S-2004, Section 12.2 (a), (b), and (c).

PG&E RESPONSE

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PG&E shares the CPUC's concern, and is working to develop a more comprehensive, consolidated Quality Control Plan that addresses all of the requirements as listed in ASME 31.8S Section 12- Quality Control Plan. However, PG&E respectfully disagrees with this violation since PG&E currently performs the breadth of QC/QA activities within its TIM Program, which align with ASME B31.8S, Section 12. These activities address the specific sections in ASME 31.8S, Section 12.2 (a), (b) and (c) and are detailed below. Attached is a table which documents many of the QC activities that are already incorporated into TIMP and the following addresses each of the ASME requirements in detail. A more detailed and comprehensive QC Plan will be developed and issued to address the ASME B31.8S requirements in one place. PG&E will achieve full implementation of the plan by the end of 2014. The new QC plan will incorporate these activities, and identify measures to track the effectiveness of the QC plan as it relates to these activities.

ASME 31.8S, Section 12.2 (a): "Requirements of a QC program include documentation, implementation and maintenance." PG&E believes that its quality assurance and control measures implemented under the TIMP address these requirements. In addition, PG&E believes that the listed activities represent essential overarching characteristics of a QC program and that the specific activities for such are detailed in Section 12.2 (b).

ASME 31.8S, Section 12.2 (b): "Specifically, activities that should be included in the quality control program are as follows". Each of the following corresponds to the associated activities as listed in this section of ASME B31.8S.

1) **Documentation:** PG&E maintains all required TIMP documentation in hardcopy format in the TIMP Library at our facility on the 4th floor of 6111 Bollinger Canyon Road, San Ramon, CA. These documents are all "controlled" and require sign in and sign out with regular inventories maintained by the TIMP Librarian. The library contains current and prior versions of Baseline Assessment Plans, results of Risk Assessments, all governing documents for the TIMP (Risk Management Procedures) as well the detailed Assessment binders covering all Baseline and Re-assessments completed as part of TIMP since the beginning of the program. All completed forms referred to in the governing documents are also maintained.

2) **Responsibilities and Authorities:** The responsibilities and authorities within TIMP for all key positions are specified within the Roles and Responsibilities (R&R) section of RMP-06 as well as under each of the subsidiary RMPs. Under the present TIMP, the Supervisors and Managers of those individuals responsible for implementation are responsible for the quality of the program as detailed later within this response and within each Risk or Implementation procedure. PG&E will be consolidating the R&R's in the next revision of RMP-06, so that they appear in this single document. The R&R's currently found within all remaining RMP's will be removed. Users will be directed to RMP-06 for R&R's for various tasks within

[redacted]

TIMP. All remaining RMP's will be updated

3) Program Results Review: PG&E performs annual reviews of the TIMP RMPs and any employee can make a recommendation as to how to continually improve this program as indicated in RMP-06, Section 16.2 As documented in each of the RMP Audit Change Logs, PG&E has continued to update and improve all of the TIMP RMPs since the beginning of the program. In 2012, PG&E performed a comprehensive update of TIMP, re-issued all existing RMPs and added several new RMPs.

4) Personnel; competent, aware and qualified: As described in RMP-06, Section 17.8, PG&E maintains the resumes as well as the training records for all TIMP personnel. Each of these positions has minimum requirements to prove competence both from a formal education standpoint (requirements documented via PG&E HR job description) as well as on the job experience and industry training. Additionally, PG&E performs annual reviews of RMPs which cover any significant changes to the applicable RMPs with TIMP employees who are required to receive this training. Further, the monthly TIMP meetings serve as a venue for the TIMP Leadership or any individual contributor to update the TIMP organization on developments that they feel all should be aware of.
Minimum qualifications for each identified TIMP role are provided in the applicable RMP, including various training requirements. PG&E regularly sends TIMP employees to industry courses, as documented in the individual annual "Development Plans" as well as bringing in industry experts to teach courses at PG&E's facilities. In recent years, these have included such courses as the Penspen "Defect Assessment" class and the GTI "ECDA Assessment" class. PG&E is working internally to centralize TIMP training scheduling and completion tracking with all other PG&E training through the "PG&E Academy". Presently all TIMP qualification and training records are maintained electronically via an internal shared drive by each employee.

5) Monitor IM Program: PG&E has incorporated specific control points in each of the TIMP RMPs by means of requiring Supervisor approval and on key documents, Manager level review and formal approval prior to the work proceeding or the documentation being finalized. PG&E takes these reviews and sign offs very seriously. The main criteria/performance metric that PG&E sets for TIMP is the completion of all assessments or re-assessments, addressing the applicable threats, prior to the due date for such. This information is tracked by the Risk Team via Assessment Tables that are tied to each HCA identified in GIS and reported monthly as described in RMP-06, Section 17.2. PG&E tracks additional metrics as described in RMP-06, Section 14.1, including transmission immediate and scheduled repairs as well as leaks, failures and incidents by cause. This information is utilized as a way to determine if additional program enhancements should be considered as described in RMP-06, Section 17.4

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6) Periodic Internal Audits: Per RMP-06, Section 17.6, either an internal audit or a third party audit is required for TIMP every other year. In recent years, due to the focus on PG&E's TIMP, this requirement has been exceeded. In May of 2010 the CPUC performed an independent audit of TIMP which was followed by an audit of Protocol "C" in April of 2011 and the remaining Protocols in August/September of 2012 to which this is part of the response. Further, in addition to the TIMP related issues identified by the NTSB, the Independent Review Panel and the Blacksmith Group, PG&E hired DNV to perform a comprehensive review of TIMP, which was completed in 2012. PG&E plans to utilize our Internal Auditing organization to perform periodic audits of specific portions of TIMP on a going forward basis following the 2014 planned CPUC audit.

7) Corrective Actions: TIMP has tracked to completion the updates to RMPs and TIMP processes identified by the internal and external audits referenced in Item #6 and as required in RMP-06, Section 17.6 and 17.7. Historically these were tracked via the PG&E ECTS. With PG&E Gas Operations transitions to the use of a SAP based Corrective Action Program, TIMP will utilize such for tracking the resolution of issues that we become aware of via audits as well as any issues which are determined to meet specific criteria from other sources. Training for all key TIMP personnel on this new system is scheduled for spring of 2014.

ASME 31.8S, Section 12.2 (c): "When an operator chooses to use outside resources to conduct any process that affects the quality of the IM program, the operator shall ensure control of such processes and document them within the quality program." The principal tools which PG&E utilizes to ensure quality by TIMP related work performed by contractors are the contract specification (as described in RMP-06, Section 17.9), inspection of the work in the field by qualified individuals as well as the validation of results via follow up activities. For inspections, PG&E has very detailed specifications which include requirements for contractor personnel qualifications, the documentation for which must be provided to PG&E following the assessment activities. Additionally, PG&E has TIMP personnel in the field when work is being performed to verify that the work meets PG&E's expectations and contract requirements.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Create QA/QC Plan	12/31/2014		Risk Management

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Update Roles and Responsibilities in RMP-06	6/30/2014		Risk Management

Definitions: NOV – Notice of Violation
AOC – Area of Concern

[redacted]

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INSPECTION INFORMATION

Inspection Dates	Finding	CPUC Contact	CPUC Phone #
August 27-31, 2012 September 10-14, 2012	NOV-7.2	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	**7. <u>Title 49, Code of Federal Regulations (CFR), § 192.907 What must an operator do to implement this subpart?</u>** 2. According to ASME B31.8S-2004, Section 12.2 (b) (2), operators are required to clearly and formally define the responsibilities and authorities of the personnel who are in charge of the QC program of the TIMP. In RMP-06, Section 4.0, Roles and Responsibilities, PG&E defines in Table 1 the titles of its personnel who are responsible for performing the tasks within its TIMP. However, PG&E does not provide the titles of the individuals who are responsible for QC and QA Programs. PG&E must identify its personnel with their specific responsibilities and authorities for implementing the QC and QA plans in order to verify the implementation and effectiveness of its TIMP.

PG&E RESPONSE

PG&E respectfully disagrees with this violation. Individuals responsible for TIMP implementation are also responsible for the quality of the program as detailed within each Risk or Implementation RMP. The specific roles and responsibilities of defined positions are described in more detail in RMP-06, Section 4 as well as the corresponding Roles and Responsibilities section of each of the applicable RMPs that make up TIMP. PG&E understands the CPUC's concern regarding this issue, and acknowledges that there is a need to consolidate this documentation and to more clearly document the QC/QA function associated with various positions in the next RMP-06 update, as stated in NOV #7.1.

ATTACHMENTS

None

ACTION REQUIRED

Definitions: NOV – Notice of Violation
AOC – Area of Concern

[redacted]

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Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update Roles and Responsibilities in RMP-06	6/30/2014		Risk Management

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August 27-31, 2012 September 10-14, 2012	NOV-8.1	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding

8. **<u>Title 49, Code of Federal Regulations (CFR), § 192.915 What knowledge and training must personnel have to carry out an integrity management program?</u>**

   1. SED reviewed training records of PG&E TIMP program supervisors, project managers, and project engineers and identified some deficiencies. SED found that some employees who are responsible for the assigned Risk Assessment Procedures did not take some Required (R) classes. Table 2 shows the name of the required classes that responsible IM group members failed to complete by their assigned projects. Please provide SED with updated training records of PG&E TIMP team members.

Table 2- List of required training courses not taken by PG&E IM group

Required Courses	ECDA	ICDA	SCCDA	ILI	LTIMP
Supervisor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] RMP-17 training
Project Manager	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Project Engineer	[redacted] PG&E Bell Hole Inspection training	[redacted]	[redacted]	[redacted] RMP-06 training	[redacted] RMP-17 training
Project Engineer				[redacted]	[redacted] RMP-17

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				PG&E GT&D Corrosion Control training	training
Project Engineer				[redacted] RMP-06 training PG&E GT&D Corrosion Control training	[redacted] RMP-06 training RMP-17 training
Project Engineer				[redacted] RMP-06 training PG&E GT&D Corrosion Control training Pipeline Defect Assessment Course training	

ECDA: External Corrosion Direct Assessment
ICDA: Internal Corrosion Direct Assessment
SCCDA: Stress Corrosion Cracking Direct Assessment
ILI: In-line Inspection
LTIMP: Long Term Integrity Management Plan

PG&E RESPONSE

PG&E agrees with this violation.

PG&E's Integrity Management Group is dedicated to providing training to its employees and takes this issue very seriously. Each employee possesses their own personal Training

Plan which is developed at the beginning of their employment with the group. The employee and supervisor work together to identify all required trainings, as specified in the applicable RMPs, along with any desired trainings that would further enhance their skills and increase their functional expertise. Since it's neither feasible nor practical for employees to attend all required trainings immediately, the supervisor and employee develop strategically prioritized timeframes for completing each action item. In many cases, the employee benefits from obtaining on-the job mentoring before attending a specific training.

PG&E is working to continuously improve its documentation for all aspects of its TIM Program, including its Training Program. PG&E appreciates the CPUC's comments, and identifying areas within the TIM Program where there are conflicting training requirements. As stated in PG&E's response for NOV # 7.1, PG&E is working to consolidate all training requirements, which will provide clarity to all TIMP personnel regarding the type and frequency of the training they require. Also, to enhance our current tracking mechanism which relies upon manual review of Microsoft Excel spreadsheets, we will investigate options with PG&E Academy to automate the custom training plans and annual requirements for each employee. This would provide greater transparency and further reduce the chance that a required training is overlooked or not completed in a timely manner. In the interim, the TIMP group will assign a training coordinator to ensure consistency in how PG&E trains personnel, assign the appropriate frequency for training, and ensure the documentation is stored in a central location

PG&E agrees that several employees had not completed "Required" trainings or procedural reviews at the time of the CPUC Audit in August of 2012. The gaps identified were specific instances where individuals had not reviewed RMP-06 and/or RMP-17, and also situations where Corrosion Control training and/or Bell-Hole Inspection training were not completed. One employee was cited for not attending Pipeline Defect Assessment training, although that person was not employed by PG&E at the time of the audit and has since completed this requirement.

Members of the ILI Engineering team were cited for not completing "RMP-06 training". RMP-11 does not specify a review of RMP-06 by its ILI Engineers. This is not consistent with RMP-06 which states all ILI Engineers shall review RMP-06. PG&E is working to consolidate the required training requirements for all TIMP personnel, as stated in NOV 7.2. In the interim, all ILI Engineers will continue to receive training on RMP-06 on an annual basis.

In 2013, the ILI engineers, (noted in Table 2 as missing this training), have completed their annual training of RMP-06 (Attachment C). All Training Plans were updated to document completion of such.

Several engineers were cited for not attending "PG&E GT&D Corrosion Control training". When RMP-11 was created originally, PG&E offered a course which fulfilled this requirement. However, this course no longer exists and PG&E proposes to update RMP-11 to allow for an industry or PG&E Academy corrosion course to replace and further enhance this requirement. PG&E believes an industry or PG&E Academy course will actually provide a more comprehensive educational experience. All ILI engineers will attend a corrosion course in 2014 and document completion of such in their respective Training Plans.

One engineer was cited for not attending PG&E Bell Hole Inspection training. This requirement will be fulfilled in 2014.

ATTACHMENTS

Attachment #	Title or Subject
C	Training Records of TIMP Employees

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Complete Training	12/31/2014		Risk Management

[redacted]

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August 27-31, 2012 September 10-14, 2012	NOV-8.2	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	
	8. <u>Title 49, Code of Federal Regulations (CFR), § 192.915 What knowledge and training must personnel have to carry out an integrity management program?</u> 2. As can be seen from Table 2, none of the LTIMP group members took the RMP-17 training class based on the information provided during the audit. PG&E explained that since it issued RMP-17 on 8/17/12, PG&E scheduled its RMP-17 training for 3/31/13. SED determined that since PG&E's LTIMP program is identified to be deficient in many aspects and some of the P&M measures proposed in the LTIMPs have not been implemented in a timely manner, PG&E must provide RMP-17 training to its LTIMP supervisor, project manager, and project engineers as well as other team members from other groups who are responsible for managing LTIMP projects as soon as possible. At a minimum, PG&E must provide RMP-17 training for all employees who perform duties such as critical assessment of LTIMP program and evaluation of efficiency and effectiveness of remedial action plans developed for each project. SED determined that in order to evaluate the effectiveness of its LTIMP program and individual plans for each project, and prioritize and execute the necessary remedial actions in a timely manner, PG&E must train all of its personnel who are in charge of managing LTIMP projects.

PG&E RESPONSE

PG&E agrees that no employees documented a formal review of RMP-17 at the time of the audit. This was a brand new procedure issued on August 9th, 2012, and in 2013 it began a significant update which will be finished in 2014. Moving forward, PG&E will ensure that all applicable employees formally review RMP-17 each year and document completion of such in their Training Plans. Employees that are responsible for identifying issues in the field, or implementing corrective actions already receive the necessary training and operator qualifications testing as part of their normal roles. Additionally, field personnel and employees outside of the TIMP group receive training on utilizing work management systems. TIMP personnel will use the same work management systems to track P&M measures and gather data for CE.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Complete Training	12/31/2014		Risk Management

[redacted]

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August 27-31, 2012 September 10-14, 2012	NOV-8.3	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	8. **Title 49, Code of Federal Regulations (CFR), § 192.915 What knowledge and training must personnel have to carry out an integrity management program?** 3. SED noted that PG&E's training guidelines lists Risk Management Procedure, RMP-06, Revision 8, Gas Transmission Integrity Management Program training class as "Desired" (D) not "Required" (R). SED determined that since RMP-06 is the controlling procedure for PG&E's Gas TIMP, PG&E must make the RMP-06 training a "Required" class instead of a "Desired" class for all of its TIMP team.

PG&E RESPONSE

PG&E agrees with this violation and will update RMP-06 to clearly specify that this review is "required" by all applicable Integrity Management employees.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-06	6/30/2014		Risk Management

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[redacted]

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INSPECTION FINDING

CPUC Finding	**8. <u>Title 49, Code of Federal Regulations (CFR), § 192.915 What knowledge and training must personnel have to carry out an integrity management program?</u>** 4. PG&E training records show that on 8/23/12, PG&E provided a training session to review the latest approved changes and status updates of RMP-06. However, some of the key personnel did not attend this class. SED also reviewed individual training plan forms and records for those who missed the RMP-06 training and noted that the following TIMP team members have never taken this class: [redacted], [redacted], [redacted], and [redacted].

PG&E RESPONSE

PG&E agrees that several employees had not completed "Required" trainings or procedural reviews at the time of the CPUC Audit in August of 2012. Below is a Training Plan update for all individuals identified in Table 2 as not completing required training courses or procedure reviews as of August 2012:

[redacted]: Bell-Hole Inspection Training will be completed in 2014.

[redacted]: A corrosion course will be completed in 2014.

[redacted]: Formal review of RMP-17 was never completed. However, shortly after the audit in late 2012, [redacted] was no longer the supervisor of the LTIMP Engineering Team.

[redacted]: A formal review or training of RMP-17 will be completed in 2014.

[redacted]: A review of RMP-06 was completed on 12/30/2013. A corrosion course will be completed in 2014.

[redacted]: No Review of RMP-17 was performed. However, [redacted] left the

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Integrity Management Group in 2013. [redacted]: [redacted] was not employed by PG&E at the time of the CPUC Audit in August of 2012, and instead was hired in September of 2012. Since then, [redacted] has completed all required trainings for an ILI Engineer with the exception of a corrosion course which he'll fulfill in 2014. Specific to the trainings/reviews in which [redacted] was cited for, he completed a review of RMP-06 on both 5/2/2013 and 12/10/2013, and he finished the Defect Assessment Course on 2/12/2013. [redacted]: A review of RMP-06 was completed on both 5/2/2013 and 12/10/2013. [redacted]: A review of RMP-06 was completed on 12/13/2013, and a formal review or training of RMP-17 will be completed in 2014.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Complete Training	12/31/2014		Risk Management

INSPECTION INFORMATION

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August 27-31, 2012 September 10-14, 2012	AOC-1.1	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	**1. <u>Title 49, Code of Federal Regulations (CFR), § 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?</u>** 1. PG&E's RMP-09, Revision 9, Procedure for External Corrosion Direct Assessment (ECDA) describes the roles and responsibilities of the Field Engineer (FE). During a discussion with PG&E representatives, SED found out that the FE's responsibilities also include designating the segment regions and selecting appropriate indirect inspection tools. PG&E should clearly define the ECDA FE's roles and responsibilities, including these

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	two important job functions in RMP-09, Section 3.0.

PG&E RESPONSE

PG&E agrees with this recommendation. As stated PG&E's response to NOV 7.2, PG&E plans to update RMP-06 with a consolidated and comprehensive list of TIMP personnel roles and responsibilities.

ATTACHMENTS

None

ACTION REQUIRED

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Update RMP-06	6/30/2014		Risk Management

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[redacted]

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August 27-31, 2012 September 10-14, 2012	AOC-1.2	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	
	1. <u>Title 49, Code of Federal Regulations (CFR), § 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?</u> 2. Title 49, CFR §192.925(b)(1)(i) states in part "…the plan's procedures for preassessment must include… Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment…" SED noted that PG&E's RMP-09 does not have a procedure to describe how it applies and documents the "more restrictive" criteria. In RMP-09, PG&E listed those activities identified in the PHMSA Gas Integrity Management FAQs as additional alternate activities for the preassessment phase when doing ECDA for the first time. As a requirement, for the preassessment phase, first time ECDA, PG&E personnel must either (1) perform a field visit or (2) collect all available corrosion records per Section 5.3.1 of RMP-09. Section 5.3.1 requires that for first time surveys, PG&E must collect all available corrosion records for the pipeline section. For instance, PG&E records for a specific casing do not clearly specify starting and ending mile points; thus PG&E would need to conduct a field visit to verify the location of the casing to accurately establish the region mile points. In this case, the field visit may not be considered "more restrictive" as the unavailability of records necessitating the field visit. If more data was collected during the field visit, such as collecting data on desired elements, that may be considered as "more restrictive", in which case PG&E will need to clearly document the additional data gathered and describe how the additional data was used for the first time ECDA. SED noted the same deficiency for the collection of all available corrosion records. SED determined that PG&E must collect all corrosion records as a part of its data gathering phase when it considers using an ECDA. Thus, PG&E must clearly describe what corrosion records it

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	considers to be "extra" or "more restrictive" than those it currently needs to determine the feasibility of ECDA. Additionally, PG&E must document and describe how it uses the additional data for the first time ECDA.

PG&E RESPONSE

PG&E acknowledges that additional clarity is required in RMP-09 to explicitly document how PG&E applies more restrictive criteria for first time assessments. Since PG&E currently implements a more restrictive criteria (see NOV 4.3), PG&E respectfully disagrees with this CPUC's concern. PG&E will update RMP-09 accordingly.

ATTACHMENTS

None

ACTION REQUIRED

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Update RMP-09	6/30/2014		Risk Management

[redacted]

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INSPECTION FINDING

CPUC Finding	1. **<u>Title 49, Code of Federal Regulations (CFR), § 192.933 (b) Discovery of condition states:</u>** Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1)-(d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable." SED found that PG&E's procedure RMP-06, Section 10.2 gives details about "Discovery of Condition" for ECDA, ILI, SCCDA, and ICDA. However, RMP-10 does not describe how PG&E documents the discovery of condition. SED noted that PG&E's RMP-10, Rev. 2, Dry Gas ICDA, Section 14 (Definitions) defines Discovery of Condition in the same way as it is defined in Title 49, CFR 192.933 (b), which states: "Discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline...." However, PG&E does not describe how it documents the discovery of condition date. PG&E should specify the date when it discovers the condition on its ICDA forms. For example, RMP-09 (ECDA) Section 7.7.3 clearly states that the Examination Date on Form H is the Discover of Condition date.

PG&E RESPONSE

PG&E agrees with this concern, and acknowledges that though RMP-10 defines "Discovery Date", RMP-10 does not specify where this information should be documented. PG&E will update RMP-10 to add the following language to Section 9.3.2 Documentation, "The Discovery Date will be documented on FORM I –"Remaining Strength Calculation and

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Root Cause Analysis". PG&E will also update Form I – "Remaining Strength Calculation and Root Cause Analysis", to add "Discovery Date" to the title block.

ATTACHMENTS

None

ACTION REQUIRED

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Update RMP-10	6/30/2014		Risk Management

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August 27-31, 2012 September 10-14, 2012	AOC-3	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	1. **<u>Title 49, Code of Federal Regulations (CFR), § 192.933 (C) Schedule for evaluation and remediation:</u>** "An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation…" SED noted that Section 9.4.2 of PG&E's procedure RMP-10, ICDA, references "Immediate Repair Conditions" but does not have any reference about how PG&E determines prioritization or the process by which it develops the schedule. PG&E should add a provision in RMP-10 for documenting how it determines the schedule by prioritizing of conditions for evaluation and remediation.

PG&E RESPONSE

PG&E agrees with this concern. While PG&E does not currently schedule evaluation and remediation for ICDA projects (all necessary repairs are completed immediately after the direct assessment), PG&E will update RMP-10 to be more explicit about how evaluation and remediation decisions are made.

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-10	6/30/2014		Risk Management

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[redacted]

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INSPECTION INFORMATION

Inspection Dates	Finding	CPUC Contact	CPUC Phone #
August 27-31, 2012 September 10-14, 2012	AOC-4	Banu Acimis	(916) 928-3826

INSPECTION FINDING

<table>
<tr>
<td>CPUC Finding</td>
<td>

1. <u>Title 49, Code of Federal Regulations (CFR), §192.933 (d) Special requirements for scheduling remediation, (1) Immediate Conditions</u>

“An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, Section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions…”

In response to the Commission’s 2010 audit, PG&E stated “Even though it is PG&E's practice to consider shutting down a line if a safety condition warrants it, based on the Commission’s feedback, PG&E’s Risk Management Procedure-11 ’In-Line Inspections’ and Risk Management Procedure-09 ’Procedure for External Corrosion Direct Assessment’ will be updated on the next revision to explicitly add this option in the event an immediate condition is reported or discovered.”

SED noted that even though PG&E included the shut-down option to Section 7.3.1.3 of RMP-11, it still does not specify the conditions that may require shutting-down the pipeline instead of lowering the pressure. Additionally, Appendix A - Direct Examination Process Flow Chart does not show the option to shut down the line.

PG&E should explicitly describe the conditions which require shutting down the pipeline in its RMP-11 and add the same notation to the flow chart in Appendix A.

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PG&E RESPONSE

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PG&E acknowledges the CPUC's concerns about safely shutting down a pipeline, and PG&E takes into consideration several factors as noted below. PG&E respectfully disagrees with this recommendation, and feels that it is not practical to explicitly describe the conditions that would require shutting down a pipeline due to the unique circumstances of each finding. However, PG&E will update RMP-11 to describe the factors PG&E will consider when making the determination to shut-down a pipeline.

Currently, when the ILI Team is notified of a significant threat to pipeline integrity, a thorough evaluation is performed to determine the safe operating pressure of the pipeline given the unique circumstances. All anomalies determined to meet the "Immediate" criteria trigger a pressure reduction of at least 20% below the Discovery Pressure. The ILI Engineer may always specify a more significant pressure reduction, including a complete shut-down, if he/she deems such is necessary to ensure the safety of the public and PG&E employees. Each case is extremely unique and must be reviewed by key stakeholders including ILI Engineering, Gas System Planning, and Gas Control. The decision to shut-down a pipeline could introduce a potential supply risk to the system and PG&E's core customers, and thus, must be closely evaluated on a case-by-case basis rather than being prescribed in RMP-11.

The following items are considered by the ILI Team when determining if a pressure reduction or full shut-down is required as a result of a condition identified using ILI, and will be added to RMP-11:

1) Risk to public safety including the proximity to HCA, structures intended for human occupancy, population density, and overall consequence of failure evaluation
2) Nature of the condition and probability of failure in the short term
3) The predicted failure pressure compared to the current operating pressure, and the level of safety margin between the predicted failure pressure and the operating pressure
4) The highest safe operating pressure in recent history compared to the discovery pressure
5) Level of confidence regarding the accuracy of condition information
6) Customer impact of pressure reduction or full shut-down

ATTACHMENTS

None

ACTION REQUIRED

Action To Be Taken	Due Date	Completion Date	Responsible Dept.
Update RMP-11	12/15/14		Risk Management

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[redacted]

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August 27-31, 2012 September 10-14, 2012	AOC-5	Banu Acimis	(916) 928-3826

INSPECTION FINDING

CPUC Finding	1. **Title 49, CFR, §192.933 (d) Special requirements for scheduling remediation, (3) Monitored conditions** "Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation: .." SED noted that there are no provisions in PG&E's procedures RMP-09 ECDA and RMP-13 SCCDA to record and monitor anomalies that are classified as "monitored conditions" during subsequent risk and integrity assessments for any change in their condition that would require remediation. RMP-06, Section 10.3.4 Monitored Conditions has a general statement on recording and monitoring of anomalies; however, there are no references in RMP-09 or RMP-13 related to recording or monitoring these conditions. PG&E should add a requirement to its RMP-09 and RMP-13 to review anomalies that it does not directly examine to determine the appropriate re-assessment intervals and long-term mitigation plans.

PG&E RESPONSE

PG&E agrees with this concern and will incorporate a requirement to review monitored anomalies that are not directly examined into the Continual Evaluation process in RMP-17.

ATTACHMENTS

None

ACTION REQUIRED

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Update RMP-17	6/30/2014		Risk Management

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