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NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

CALIFORNIA PUBLIC UTILITIES COMMISSION
OCTOBER 21, 2010 LETTER TO PG&E

(14 Pages)

STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

October 21, 2010

Mr. Glen Carter, Senior Director
Gas Engineering
Pacific Gas and Electric Company
375 North Wiget Lane
Walnut Creek, CA 94598

Re: May 2010 Integrity Management Program Audit

Dear Mr. Carter:

This is in regard to the audit of Pacific Gas and Electric Company's (PG&E) Integrity Management Program (IMP) conducted in May 2010 by staff from the Utilities Safety and Reliability Branch (USRB), of the California Public Utilities Commission's Consumer Protection and Safety Division.

The findings of the USRB audit are primarily addressed in the attachment, SUMMARY OF MAY 2010 AUDIT FINDINGS, to this letter. However, there are two particular areas of concern regarding PG&E's IMP that we would like to highlight. First, USRB believes PG&E is diluting the requirements of its IMP through its exception process and appears to be allocating insufficient resources to carry out and complete assessments in a timely manner. Second, USRB believes PG&E needs to analyze, review, and formulate appropriate actions or responses to the results of its internal audits in a timely manner. These issues are discussed in more detail below.

Issues related to exception reports:

PG&E's RMP-6, Section 18, Exception Process, addresses the company's approach to instances when deviation from the Integrity Management Program related procedures may be necessary. This same exception process is restated in other RMPs (i.e., RMP-09, Section 7, RMP-11, Section 7, RMP-10, Section 8, etc.). The exception process in RMP-6, Section 18, states: "It is expected that all requirements of this procedure be met in conducting the Integrity Management Program. However, when this is not possible, then exceptions can be made by obtaining approval...from the Manager of Integrity Management or his/her designate prior to acting on the exception."

However, the USRB noted various exception reports having been generated after the exception had been acted on. In addition, exception reports are being routinely generated and being used to provide the basis for not performing procedural activities which PG&E has identified, and made as requirements in order to make its IMP more robust in nature.

For example, within PG&E RMP-06, Sections 4.5 and 5.4, the Company's has indicated its desire to inspect pipelines utilizing In-Line Inspection (ILI) whenever it is physically and economically feasible. Some of the considerations used to determine feasibility include:

- Minimum piggable length of at least 10 miles, with more than 5 miles located in HCAs;
- Less than 0.5 miles of replacement required to make the pipeline piggable;
- Flow rates that enable a successful ILI;
- Pipeline operation over 30% SMYS;
- Operating over 40% SMYS with more than 1 mile of tape coating;
- Backbone pipeline operating over 40% SMYS with reported poor pipe conditions

However, as the following exception reports appear to show, PG&E RMP-06, Section 5.4 is not being adhered to:

1) Per the BAP, Line-400 (M.P. 82.33-142.61) was due for an ILI assessment in 2008. It had been selected for ILI due to the line being piggable and it having more HCA pipe than most piggable sections of Line 400. Although this segment had been scheduled for an ILI assessment in 2008, it was not performed in

2008. An exception report dated May 6, 2010 and approved by the Manager of Integrity Management on May 21, 2010, after the scheduled assessment year had been exceeded, moved the assessment to 2010 and converted the assessment method to ECDA. The exception report noted the change to 2010 was made because the segment did not meet all conditions per RMP-06, Section 5.4 (less than 5 miles of HCA, less than 1 mile of tape coating, and it does not have poor pipe condition reports) and "...to better level workload and funding requirements for Integrity Management and allow time for ECDA pre-inspection work to occur."

2) The same occurred for Line-401, (M.P. 82.34 – 149.19) which was slated for ILI in 2009. However, unlike Line-400, Line 401 met almost all conditions of RMP-06, Section 5.4 for choosing ILI over ECDA (i.e., this line has more than 10 miles of piggable line, operates at over 40% SMYS, has more than one mile of tape coating, and more than 5 miles of HCA mileage), the assessment was not performed in 2009. Instead, an exception report dated May 6, 2010 and approved by the Manager of Integrity Management on May 21, 2010, after the initial scheduled assessment year had been exceeded, moved the assessment to 2011 and converted the assessment method from ILI to ECDA. Exception reports, dated May 6, 2010 and approved by the Manager of Integrity Management on May 21, 2010, were also generated for Line-215 (scheduled for ILI in 2009, but ECDA'd in 2009); Line-57B (scheduled for ILI in 2008, but ECDA'd in 2008); Line-21D (scheduled for ILI in 2008, but ECDA'd in 2009); and Line-402 (scheduled for ILI assessment in 2012, but changed to ECDA as the assessment method in 2012).

3) Exception report of 12/11/08, generated for N-Seg 101-2008 (Sta 117+36) was used as basis for not excavating and examining all immediate indications from M.P. 42.24 – 44.61. Numerous exception reports, starting August 8, 2007 thru May 12, 2010, were generated for Line-21E. These exception reports were issued to justify not excavating three of 11 immediate indications reported by an ILI vendor, for examination plans delayed beyond 90 days, classification of indications downward from tool indications, delays in excavations beyond 365 days, and the generation of required root cause analysis reports delayed beyond 90 days, as required by RMP-11, Section 5.8.

4) Exception report of May 12, 2010, for Line 21-E, for not excavating and inspecting all "scheduled" anomalies within 365 days, and instead taking 27 months following final receipt of the ILI vendor report.

5) The exception report for L-2, dated 12/16/2009, which sought to delay the required issue of the root cause report from the PG&E required 90 days to 180 days, noted the reason for the exception (delay) was caused by "Corrosion engineering resources...focused on other higher priority aspects of Integrity Management. It is anticipated that the root cause analysis will be contracted to a vendor outside of PG&E for completion." The exception report also noted the exception was not unique to this project and suggested the 90 day requirement be changed to 180 days in the procedure.

6) A June 23, 2007 exception report, one of many issued for SP-3 (M.P. 167.31 – M.P. 198.05), which sought to delay the development of the inspection plan following receipt of the final ILI report from the vendor, noted as the reason for the exception: "Competing priorities within the ILI Engineering Team as well as turn over in personnel have delayed the completion of the SP-3 Dig Plan. Delays in creating this plan will not delay implementation of the dig plan beyond the required 365 days from the receipt of the Final ILI Report as required per RMP-11." In fact, several of these digs were delayed to October 1, 2010 (greatly exceeding the 365 days requirement to excavate and inspect all anomalies included on PG&E's Form G).

7) Various exception reports were noted for work delayed due to environmental permits not being filed with, or obtained from, various permitting agencies. While some delays may be attributable to permitting agency requirements, it appears another reason for delays may be due to permits not being filed for in a timely manner.

PG&E's various RMPs have specified timetables for developing inspection plans following vendor reports, excavating and inspecting anomalies from these reports, and for performing root cause analysis following direct examinations. However, as evidenced by the exception reports discussed above, PG&E appears to be diluting the requirements of its IMP through its exception process instead of allocating sufficient resources necessary to carry out and complete assessments in a timely manner, and in conformance with its specified procedures. Also, contrary to the indication that lengthening the period for providing the root cause analysis does "not jeopardize public safety because the anomalies have already been directly examined and any repairs have been made," which was noted in the December 16, 2009 exception report for L-2, we believe it is important that root cause analysis, because it aids in determining the suitability of the assessment process and the identification of effective mitigative measures, be performed in a timely manner and following soon after the performance of the direct examination digs. Delays in root cause analysis further delay completion of final assessment reports, and may result in the need for additional exception reports being issued.

Issues related to external audits of PG&E's IMP performed by PG&E's consultants.

The USRB team reviewed reports for two internal audits related to PG&E's Integrity Management Program (IMP), which were done for PG&E by two different contractors. The first audit, conducted in December 2007, examined various IM assessments which had been completed by PG&E. It appeared that PG&E did not formulate a position/response to the 2007 audit findings until December 2009. The second audit, conducted in October 2009, focused its review on risk assessment and risk management aspects of PG&E overall IMP. By the time of the USRB audit, PG&E had not formulated a position/response on the findings from the audit.

The 2007 audit review noted that RMP-09, Table 3.3.1, which defines PG&E's Pre-assessment Data List (Table A, and the Data Element Check Sheet) did not capture the girth weld coating as required ECDA data per NACE 0502. PG&E indicated it did not capture this data because it was difficult to locate; however, we believe difficulty should not prevent PG&E from obtaining this and all required data per NACE requirements.

The 2007 audit also recommended that the Direct Examination Process Flow Chart, Attachment A in RMP-11, be adapted into RMP-09 and that completion dates for final reports from RMP-11, Attachment A (45 days from completion of Root Cause Analysis, and within 135 days from completion of Field Inspection and Repairs) be specified for final reports. PG&E responded that it's then current process specified that its Root Cause Analysis needed to be completed within 90 days of receipt of the field examination report by the vendor; however "In many cases to date this has not happened due to lack of resources in the Corrosion Engineering Group who perform the Root Cause Analysis." PG&E noted that its ILI final reports are not tied to completion of repairs, but only completion of Root Cause Analysis being performed. PG&E further noted it considered the Root Cause Analysis as part of the Final PG&E report, and believed "...the report can't be finalized until this analysis is complete."

Through the 2007 audit, PG&E also recognized that it did not have a mechanism for tracking recommendations made in the Root Cause Analysis. In Revision 5, dated May 13, 2010, PG&E modified Section 9 and 13 of its RMP-06 to require tracking of root cause analysis reports and recommendations; however, it has not clarified that root cause analysis needs to be performed before completing the assessment. This includes any monitored indications examined, since NACE 0502, Section 5.6 does not make an exception for monitored indications.

The audit conducted in 2009 by PG&E's consultant noted that PG&E's current risk assessment methodology, although consistent with models in widespread use by many pipeline operators, could be improved upon. The review noted that PG&E had not well defined, and may have made too subjective, the provisions for assessing the performance of its model. The review recommended PG&E make use of statistical and graphic analysis to monitor the performance of its risk assessment process. However, as noted earlier, PG&E had not formulated a position on its consultant's recommendations. USRB believes PG&E needs to review these and future recommendations in a timely manner, and formulate appropriate actions based on these recommendations.

Please provide a response to the findings noted in this letter and the attached SUMMARY OF MAY 2010 AUDIT FINDINGS, by November 22, 2010.

Sincerely,

Michael Robertson
Program and Project Supervisor
Utilities Safety and Reliability Branch

C: Julie Halligan, CPUC
Raffy Stepanian, CPUC
Sunil K. Shori, CPUC

Attachment: SUMMARY OF MAY 2010 AUDIT FINDINGS

SUMMARY OF MAY 2010 AUDIT FINDINGS
PACIFIC GAS & ELECTRIC COMPANY (PG&E)
INTERGRITY MANAGEMENT PROGRAM

I. Audit Findings Identified in Protocol Area A. Identified HCAs:

A.01.d. – We were unable to confirm if all HCA segments existing in 2004 were added to the baseline assessment by December 17, 2004. In addition, we are concerned there may be other MOP segments that are 20% transmission, which may not have been included in the baseline assessment. We requested that PG&E provide information related to a study being performed by the company to confirm this, but PG&E indicated no documentation was available. 49 Code of Federal Regulations (CFR), Part 192, §192.947(d) requires such documentation to be maintained and available for review during an inspection.

A.02.a. – PG&E has no requirement to use the 0.73 factor for rich natural gas.

A.03.a. – PG&E RMP-06 didn't list the sources for the data selected in identifying the identified sites.

A.03.b. – PG&E has no process for assuring that any HCA information received from sources outside the IM Group is properly and timely tracked, documented, and integrated into the BAP.

A.05.a. – PG&E is not using prorating. PG&E is using MOP instead of MAOP to determine where HCA segments exist on its system which is an issue. PG&E is conducting a survey to identify any portions of its pipeline system where MOP and MAOP of line, applied to a given segments characteristics (i.e., pipe wall thickness) would render the segment as being 20% transmission and subject to IM, Subpart O requirements. This may result in additional HCAs being identified. Such an identification should have occurred much earlier in the program. We requested that PG&E provide copies of updates it has received from its vendor (Dan Curtiss – MEARS) related to the survey. However, PG&E refused to provide the updates although the audit team believes they are reviewable documents (CFR §192.947(d)).

A.05.b. – Same as A.05.a.

A.06.a. – PG&E needs to modify its RMP-06 (Sections 17.2 and 17.3) to add a process to more thoroughly review new HCAs in order to identify any that existed during previous reviews, but were somehow not identified and missed from inclusion into the IMP. Such a review should document the reason(s) for the HCA being added to the IMP as well as a determination of why the HCA may not have been identified during the last review. The review process could help PG&E identify program deficiencies (i.e., errors in pipeline data, buffers applied, etc.) that could be attributing to all HCAs not being identified and included in it IMP.

II. <u>Audit Findings Identified in Protocol Area B. Baseline Assessment Plan:</u>

B.01.b. – PG&E has not documented that it is evaluating all the considerations from ASME B31.8S, Section 6.2.5, for selecting an internal inspection tool. PG&E RMP-11, Section 4.3.1.2 has some, but not all, of the ASME B31.8S considerations listed.

B.02.a. – PG&E's GIS has specific dates for reassessments; however, not for assessments. PG&E is not updating its BAP with specific dates and is only documenting the calendar years for reassessments and assessments still to be performed even those that are near term. Pipeline and Hazardous Materials Safety Administration (PHMSA) FAQ-39 suggests specific dates be indicated in BAP updates as assessments come closer in time to being performed.

B.02.c. – PG&E RMP-06, Section 4.3, does not include the requirement to prioritize LFERW as high risk for any "covered or non-covered segment where in the pipeline system ...has experienced seam failure." (i.e., it speaks to covered, but not to non-covered segments.)

B.02.e. – PG&E needs to have date specific information, in the BAP as assessment dates approach. Also, for DA, PG&E is considering the end of its ECDA Step 3 as being the end of its assessment and counting the mileage as completed for DA. However, per PHMSA FAQ-34, the baseline assessment is not considered complete until "the last direct examination associated with direct assessment is made..." Per NACE RP0502-2002, Figure 7, direct examinations for process validation, performed per NACE RP0502, Section 6.4.2, are the last direct examinations associated with direct assessment. Therefore, it appears that PG&E may be incorrectly counting completed DA mileage within its IMP.

B.03.a. – The PG&E LTIMP for Line 300A South identified a Hard Spot threat; however, no assessment has been conducted for this threat. (Line 172 had an identified hard spot failure and an ILI tool capable of hard spot detection was run on that line on 5/24/2005.) A corrosion growth rate of 1 mil/year was used on 300A South (amended report) while 12 mils/year was used on Line 57B because no "detailed CP information" was used by the corrosion engineer. PG&E needs to justify the corrosion growth rates used in determining reassessment intervals. As noted in RMP-09, Section 6.2.2.3, *"Exceptions: ASME B31.8S (2001) page 63, Table B1, shows average corrosion rates related to soil resistivity which are provided in Table 6.2.1. Other corrosion rates that are scientifically supported may also be used. The Manager of CE&DA shall approve using these rates..."* Therefore, please provide the justification for the 1 mil/year corrosion rate identified for Line 300A South and the approval of the manager of CE&DA. The compliance file for Line 57B did not contain documentation of what threats, other than EC, were considered, evaluated and/or assessed on Line 57B.

PG&E did not have LTIMPs for Line 2 and Line 57 because re-assessments were performed in 2008 before the LTIMP could be assembled. PG&E should have had the LTIMPs in place at least by 2007 to identify and address all other threats not assessed by the ILI run.

B.04.a. – PG&E has no formal process to track and integrate new HCAs that are not part of the annual review into the BAP. The date that the HCA is discovered should be better recorded in order to confirm compliance. Finally, the USRB team had a concern that PG&E is not performing any investigations to confirm, when an HCA is newly identified, if the HCA is one that existed in 2004 (or when other reviews were performed prior to the date of discovery of the HCA) but was somehow missed. Such an investigation could help PG&E better validate its HCA identification process.

III. Audit Findings Identified in Protocol Area C. Identify Threats, Data Integration, and Risk Assessment:

C.01.a. – Protocol C.01.a.xi requires "all other potential threats" be identified and evaluated; however, PG&E has not developed a process for evaluating the threat of equipment failure and is not mandating hard spots (RMP-06, Section 3) to be assessed, although they have been identified as a possible threat, before considering assessment or mitigation efforts are completed. 49 CFR §192.917(a) states in part: "An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME…" Per 49 CFR §192.917(c), an operator must conduct a risk assessment that considers the threats and aids in prioritizing the covered segment for the baseline and continual assessments. For equipment threats, ASME B31.8S, Section A6.2 (page 49) specifies minimal data sets to be collected and reviewed before a risk assessment can be conducted. PG&E has not collected this data set, nor attempted to identify particular equipment threats on any given segment.

C.02.a. – PG&E has identified Equipment Failure as a threat, although it's unclear how this threat is assessed and/or if previous equipment related data has been integrated into the BAP. PG&E RMP-06, Section 2.4, mentions a procedure for determining equipment threat; however, the procedure doesn't exist according to PG&E. PG&E did not integrate equipment data in BAPs established in 2004.

C.02.b. – It does not appear that PG&E has integrated patrolling records into its GIS.

C.02.f. – PG&E is not currently entering USA information into its GIS, nor is it entering any patrol findings that could impact transmission pipelines. (PHMSA FAQ-81 requires: "Information related to determining the potential for, and preventing damage due to excavation, including damage prevention activities…" be integrated in performing a continual evaluation of pipeline integrity.) PHMSA FAQ-240 (paragraph 4) also speaks to this, as well as ASME B31.8S, Section A7.2 also requires one-call to be integrated.

C.03.c. – PG&E RMP-01, Section 6.4.3, states: "The committee has determined that the factors in A through D of this section are significant for determining the reliability impact of a gas pipeline failure." However, there are only factors A through C listed under that section. PG&E RMP-01 needs to be revised to either add factor D, or indicate if only factors A through C apply.

C.03.e. – Exception report had to be issued due to unavailability of personnel from steering committees to meet due to other (parcel entry) work having to be done at the end of the year.

C.04.a. – PG&E IMP Consequence Committee did not meet in 2008 or 2009. PG&E staff indicated that per PG&E RMP-06, Section 18, Exception Process allowed for the annual meeting requirement to be waived. It would appear that an annual meeting is required by code since RISK, of which consequence is one factor, has to be evaluated at least annually. PG&E believes the meetings in 2008 and 2009 were not necessary since consequences, which are driven by PIC calculations, do not significantly change.

In addition, the 2009 minutes from the meeting of the PG&E IMP Ground Movement Committee did not clearly indicate that all items required to be reviewed by PG&E RMP-01, Section 6.2.5 were reviewed (i.e., LOF x COF list was unavailable during the meeting so only the LOF list was reviewed.) FAQ-234 and ASME B31.8S, Section 5.8 require annual review of RISK.

Finally, a PG&E e-mail, detailing meeting minutes from the 2009 meeting of PG&E IMP External Corrosion Committee, lacks any detail or support for the decision making process used to modify PG&E RMP-02.

IV. Audit Findings Identified in Protocol Area D. DA Plan:

D.02.b. – Pre-assessments are supposed to be performed as the first STEP in order to identify regions, tool selection, and ECDA feasibility; however, PG&E conducted a pre-assessment following other ECDA steps having commenced (example: N-Seg 177 (2008)). In addition, PG&E is conducting concurrent pre-assessment and indirect assessment activities on a routine basis (i.e., N-Seg 131, route #DREG4718, HCA segments 201 and 203) where tool selection is preordained and the feasibility of the ECDA process is forced to be a given.

D.02.d. – PG&E groups all casings into only 2 regions - Region 3 and Region 8, in which the later region was recently added due to temperature gradient, SCC, and condensate concerns. Casings are aggregated by region and year for all segments (N-Segs) on which assessments are performed in a given year. Casing assessments are performed from an aggregated pool from which digs are then initiated. PG&E's grouping of its casings does not follow the March 1, 2010, PHMSA Guidance, "Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs." The guidance developed guidelines for establishing ECDA regions for cased pipe. Six attributes required separate ECDA regions and eleven attributes must be considered when determining ECDA regions, but alone does not always require a separate ECDA region. During an April 2010 workshop, PHMSA provided additional clarification on guidance related to casing assessments and reinforced its expectation for operators to utilize the guidance in completing casings assessments by December 17, 2012. During the audit, PG&E staff stated that PG&E does not plan on utilizing the March 1, 2010, in regionalizing casings per the PHMSA Guidance.

PG&E schedules Regions 1 and 2, along with 5, for excavation as indirect assessments are received, whereas other casing regions are grouped together and dug from a "pool" of potential tool dig sites. This process is not allowed for by 49 CFR §192 or NACE RP0502. (This process fails to consider CP variations and CP historical deficiencies applicable to casings on different segments.)

D.03.a. – PG&E RMP-09, Sections 4.3 and 4.4.3, doesn't specify the physical spacing of readings but it indicates to follow the different indirect inspection tool procedures. A copy of MEARS DCVG specified no spacing interval to be used for readings, nor did it specify any process for changing spacing due to indications.

D.03.b. – PG&E RMP-09 provides no direction for decreasing interval spacing when an indication is encountered.

D.04.a – PG&E needs to clarify RMP-09, Section 5.3.1 (page 45 of 204). It discusses a typical length of 12-feet, centered on the indication, for the purpose of exposing approximately 10-feet of pipeline for direct examination. However, it appeared from records review that only 10-foot excavations are being performed.

In PG&E RMP-09, Section 5.6, Table 5.6.4, the Data Elements 1.9 & 1.10 are found in the table as being "Required". However, those Data Elements are not found in the "Direct Examination Data Sheet (Casing Only) Page 1 of 1, Form H.

In PG&E RMP-09, Section 5.3.3.1, Table 5.3.1 states that PG&E is conducting just one addition dig if there was an immediate and schedule found and not the addition two digs for the first time through as required in NACE RP0502, Section 5.10.2.2.2 and PG&E RMP-09, Section 5.3.3.1. Example in PG&E RMP-09 shows how PG&E interprets NACE RP0502, Section 5.10.2.2.2.

In PG&E RMP-09, Section 5.3.2.1, it states in part that PG&E does reprioritize even immediate digs after sampling "some" immediate indications. PG&E is not following NACE RP0502 requirement to dig ALL immediate indications and to not reprioritize indications the first time ECDA is applied to a given segment. PG&E presented a white paper that essentially considers "should" from the NACE RP0502 document as a suggestion and not requirement.

D.04.b. PG&E RMP-09, Section 5.7, and all related forms need to be modified to mandate a 10% pressure reduction, as required by PG&E Utility Operation Standards 4134, if mechanical damage is found during the direct examination process.

D.04.f. – PG&E presented a "MEMO TO FILE", dated May 20, 2010, in which it allows for reclassification or re-prioritization of indications, regardless if assessment is performed the first time or subsequent assessment. This goes against NACE RP 0502 (2002) which discourages such a practice. Also, PG&E's definition of first time application of ECDA is inconsistent with NACE 0502, Section 5.8.4.2 which discusses "initial ECDA" vs. PG&E's "first time ECDA is used." It should also be noted that the May 20, 2010 memo, which was created during the audit, could not retroactively apply to any reprioritizations performed prior to its creation since justification had not been provided for such reprioritizations.

D.04.g. – PG&E did not have a written process which clarifies the criteria and internal notification procedures for any changes in the ECDA Plan as required by the protocol.

D.05.c. – PG&E provided a copy of a "MEMO TO FILE", dated December 23, 2009, in which the company allows the random effectiveness direct examination location to be chosen from established data sets that contain possible third party damage, possible old corrosion, or other indications that will verify the successfulness of the ECDA process. The memo restates the definition of "Random" as contained in PG&E RMP-09 (Rev 7) as being "Statistics relating or belonging to a set in which all members have the same probability of occurrence..." It provides as examples of sets of indications such as Scheduled, Monitor, etc. However, another definition (per Encarta Dictionary) defines "random" as: "done, chosen, or occurring without an identifiable pattern, plan, system, or connection."

The USRB team believes PG&E's process for selecting a random confirmation dig conflicts with NACE RP0502, Section 6.4.2 which states in part, "At least one additional direct examination at a **randomly** (emphasis added) selected location shall be conducted to provide additional confirmation that the ECDA process has been successful." Since PG&E's selection process, for selecting locations for determining the effectiveness of its DA process, utilizes established data sets of third party damage or old corrosion to guide in the selection locations, the USRB teams believes it constitutes "an identifiable pattern, plan, or system..." which does not provide for a truly random selection process.

D.06.a. During our audit, we were unable to confirm if the Supervising Engineer, the ICDA Project Manager, and the ICDA Project Engineer had received formal training as required by RMP-10, Sections 2.3.2, 2.3.3., and 2.3.4, respectively.

D.06.b. – PG&E RMP-10 does not have an explicit requirement that the ICDA be carried out on the entire pipeline in which covered segments are present. (49 CFR §192.927).

D.07.a. – In PG&E RMP-10, Section 4.2.4.2, instead of consider supplementing USGS data if inaccurate data is available, this step needs to be made mandatory if inaccurate data is available. Modify PG&E RMP-10, Section 4.3.3 and other "may"; "could", etc. statements to be more definitive. PG&E RMP-10, Section 4.4.1 needs to clearly define what is considered as "sufficient" data. Also, Section 4.3.3, only provides for recommended attendees for the pre-assessment review meeting; however, we believe this section needs to specify required attendees essential to the purpose of the meeting.

D.08.a. – In PG&E RMP-10, Section 6.2.3, "pipeline operator" needs to be made specific to PG&E personnel responsible.

PG&E RMP-10, Section 6.2.3.1: We believe this section is intended to reference 5.5.9 instead of 5.5.10.

PG&E RMP-10, Section 6.2.5 needs to provide more direction as to how many, and at what locations, additional direct examinations could be performed.

D.08.e. – PG&E indicated it is performing GWUT to inspect non-exposed pipe wall during direct examinations; however, in PG&E RMP-10, Section 6.3.7, this GWUT is stated as something that "may" be done to augment the direct examination process. The "may" needs to be removed from the section and replaced as a requirement.

D.09.b. – PG&E RMP-10, Section 7.3.4, replace "should" with the word shall since these are performance measures required by ASME B31.8S.

D.09.c. – PG&E RMP-10, Section 7.2.2 needs to provide more detail on determining the frequency for monitoring of the conditions listed, as well as who will make that determination. Also, what constitutes "periodically" in the drawing of liquid samples from low points.

D.09.d. – PG&E has assumed corrosion of 20% wall, even at locations where none has been found, compared that to the length of time the pipeline has been in operation, and then used that data to calculate remaining ½ life. Although PG&E indicated it is doing this step, it is not written out as a requirement within PG&E RMP-10.

D.11.a. – PG&E RMP-13 does not detail the requirement of ASME B31.8S related to missing data; (D.11.a. iii) requires segments to be prioritized higher or conservative assumptions to be used.

D.12.b. – PG&E RMP-13 does not explicitly require the hydrostatic test required by ASME B31.8S, Appendix A3.4.

V. <u>Audit Findings Identified in Protocol Area E. Remediation:</u>

E.01.a. – PG&E RMP-06, Section 6.4 has to be made PG&E-specific and detail what PG&E defines as its discovery date. Also, PG&E RMP-06 provides no "discovery of condition" definition for ICDA.

E.01.b. – PG&E RMP-11 does not have an explicit requirement to document the date of discovery using whichever form PG&E may dedicate for the documentation. The same concern applies to PG&E RMP-09 which also does not have an explicit requirement.

E.02.a. – Although PG&E RMP-11, Section 5.3.3 speaks to reducing pressure to address a safety issue on the line due to an immediate condition; however, the option to shut down the line, or under what situations scenarios the line would be shut-down, is not addressed by the RMP.

E.02.c. – PG&E RMP-11, Section 5.5, does not provide for requirements to record and monitor anomalies classified as "monitored conditions" during subsequent risk or integrity assessments for any changes in their status that would require remediation.

E.03.a. – In PG&E RMP-11, Section 5.3.3, PG&E uses the highest operating pressure, occurring anytime between the time period the pig run is made and the time a pressure reduction is determined as the pressure from which a 20% reduction is made. This does not comply with reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. A provision in 49 CFR §192.933 exists to address circumstances under which a 20% reduction cannot be taken. 49 CFR §192.933 states in part: "An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State."

E.03.b. – PG&E needs to make it clear in RMP-09, Section 7 and PG&E RMP-11, Section 7, that the basis for why public safety will not be jeopardized needs to be documented when evaluation and remediation activity cannot be completed within established timeframe requirements. Form M, from PG&E RMP-11 has the field to document this requirement.

E.04.a. – PG&E RMP-09 requires that the first excavation commence within 180 days of the assessment. It is the goal of 49 CFR §192.933(b) to have discovery of all potentially unsafe conditions from the assessment/re-assessment occur within 180 days and not just the have the first dig take place within 180 days. 49 CFR §192.933 states in part: "...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..."

E.04.b. – RMP-09 gives the contractor 90 days to provide PG&E the results of the indirect examination. PG&E performs its analysis of the indications within 1 month after receipt of data. PG&E then has 180 days from the receipt of the indirect inspection report to perform its first excavation. This process sums up to about 270 days from the completion of the indirect inspection. This does not meet 49 CFR § 192.933(b) which requires that, within 180 days after conducting an integrity assessment, the operator makes a determination if a condition presents a potential threat.

E.04.c. – Although PG&E RMP-09, Section 5.3.1 states that a 12-foot excavation, centered on the anomaly, is the length of the typical excavation performed. PG&E RMP-09, Form H documents indicate planned/actual excavations to be 10-feet in length. This leaves little buffer for GPS inaccuracies even when sub-meter GPS is used.

E.04.e, – Under exception report of December 11, 2008, generated by PG&E for N-Seg 101-2008 (Sta 117+36), PG&E did not dig all immediate indications from M.P. 42.24 to 44.61, PG&E examined 4 of the 7 immediate excavations specified by the ECDA IIT. PG&E's exception report stated that enough information had been gained from the examination of the 4 indications that the remaining 3 immediate indications did not need to be examined. However, this does not comply with ASME, B31.8S-2004, Section 7, or 49 CFR, §192.933(d)(1). This finding serves as one example where the USRB team found PG&E to be non-compliant with this protocol. However, based on the copy of PG&E's May 20, 2010 memo, *PG&E Justification of Reprioritization for First Time ECDA*, provided to the team during the audit, the team believes there are potentially more instances in which PG&E may not have evaluated or remediated immediate indications in full compliance with ASME, B31.8S-2004, Section 7, or 49 CFR, §192.933(d)(1).

VI. <u>Audit Findings Identified in Protocol Area F. Continual Evaluation and Assessment:</u>

F.01.b. – Risk not evaluated in 2009 since the committees didn't meet.

F.01.d. – PG&E performs an annual risk review for every segment, covered and non-covered, to reassess risk. Risk not evaluated in 2009 since the committees didn't meet.

VII. Audit Findings Identified in Protocol Area H. Preventive and Mitigative Measures:

H.02.a. – PG&E is performing Gas Event and Near Hit Reporting (WP1465-02) to perform root cause analysis of all excavation related damages (distribution and transmission) to improve damage prevention efforts. PG&E's procedure for performing excavations, or above ground surveys when evidence of unmonitored encroachment are found (WP4412-05, Section 5.B.) needs to clearly state that the "2 feet of the underground facility…" means 2-feet of the outermost edge of the pipeline. Also, the instructions for Form 62-4060 do not explicitly require that the form be submitted to IM staff if an excavation is performed to examine potential encroachment in an HCA and, possibly, on any locations not in HCAs.

H.05.a. – PG&E uses its RMI-04 and RMI-04A to determine "triggers" that would initiate a review of segments susceptible to outside force following heavy rain or g-force events. However, there appears to be no process for initiating additional patrols prior to the triggers occurring (i.e., for locations that may require more patrols than routinely required by 49 CFR §192). PG&E stated it actively works to relocate sections located within known earthquake crossings. The processes seem to address a response to an event; however, the process does not address what is done to increase patrols that may be conducted, for P&M, for existing known threats of outside force.

H.07.a. – PG&E has not developed specific guidelines (especially none which consider items listed under H.07.a.) for utilizing in-line valves (although PG&E RMP-06 indicated this was to have been done by 12/31/2009) for pipeline integrity management. PG&E staff could provide no response why the guidelines were not completed by that date.

H.08.a. – PG&E stated that IM personnel consider P&M measures input from field staff through the pre-assessment (field interview) stage as well as at the tail end LTIMP meeting. However, there is no written formal process for this nor does anything state who has to be part of the LTIMP review team. The LTIMPs reviewed also provided no details as to how specific P&M measures were considered to address threats to each covered segment included in the LTIMP.

H.08.c. – Schedules appear to be extended from year to year without clear basis of why.

VIII. Audit Findings Identified in Protocol Area I. Performance Measures:

I.02.a. – PG&E counts mileage as being assessed at the end of the completion of direct examinations; however, per PHMSA FAQ-34, mileage is to be assessed at the conclusion of the "the last direct examination associated with direct assessment is made…" This would mean that PG&E needs to count mileage as completed after validation digs are performed, and not the last dig performed as part of the Phase 2 step of direct assessment. This is also consistent with NACE RP-0502, Section 6.4.2, which considers the direct examination dig, for process validation, to be the last examination associated with the direct assessment process.

IX. Audit Findings Identified in Protocol Area J. Record Keeping:

J.01.a. – PG&E could not provide records to show that its steering committees are meeting on an annual basis, as required by PG&E RMP-01, Section 6.2 and PG&E RMP-06, Section 3.4. No meeting minutes from 2007 were provided. In addition, PG&E's records process needs to provide more detail/rational supporting decisions made through the meetings and confirmation that the meetings are conducted, and records reviewed per PG&E RMP-01. [EC meeting minutes (07/08/2009 e-mail from Kevin Armato) is an example of this.]

X. Audit Findings Identified in Protocol Area K. Manage of Change (MOC):

K.01.a. – PG&E ICDA performed in 2005 and 2007 was done under a draft (framework) procedure. The approval of a new procedure didn't occur until late 2009 early 2010.

K.02.c. – There is no written process for communicating changes to vendors (i.e., MEARS) and what follow-up is reviewed to confirm that the changes were properly implemented by the vendor. Time limitations need to also be specified to make certain that changes are communicated well in advance of the expected date when changes are to be put into effect.

XI. Audit Findings Identified in Protocol Area L. Quality Assurance:

L.01.b. – In Year 2007, PG&E had a review performed by P-PIC; however, it appears that PG&E did not review the report from P-PIC, and formulate a position/response on its findings, until December 2009 (Rev7 to PG&E RMP-09 mentioned on page 10 of PG&E response). In October 2009, PG&E had an external review done of its ILI and DA but as of the time of the PUC Audit, PG&E had not formulated a position/response on that review's findings. PG&E needs to review the recommendations and act on them in a timely manner.

L.01.c. – There is no formal process created to document and monitor the effectiveness of corrective actions taken to improve the integrity management program. PG&E essentially considers the change form for PG&E RMP-06 as being the documentation for effectiveness; however, there are no other details as to what exactly was looked at during each annual process to review PG&E RMP-06. Also, no timetables are specified for the changes/reviews of the effectiveness.

L.02.b. – PG&E receives OQ records for all MEARS personnel prior to their performing a covered task. ASME B31.8S, Section 12.2(b)(4) states in part: "the personnel involved in the integrity management program shall be competent, aware of the program and all of its activities, and be qualified to execute the activities within the program. Documentation of such competence, awareness, and qualification, and <u>the processes for their achievement</u> (emphasis added), shall be part of the quality control plan." Based on review of records for Bryan Winget, PG&E does not appear to have a written process (i.e., priority of training, specific timetables for training, etc.). Although training requirements are mentioned in various RMPs, we were uncertain, and unable to clearly confirm how and when the training is being provided.

L.03.c. – PG&E did provide a white paper for a "should" related to its reprioritizing of indications, including immediate indications, on any assessment first time or not. However, this paper was only put to file on May 20, 2010. PG&E stated there are similar documented justifications included for its various RMPs.

XII. Audit Findings Identified in Protocol Area M. Communications Plan:

M.01.b. – PG&E RMP-06 requires company wide e-mails, from VP of Gas Transmission and Distribution, to be distributed informing transmission staff about IM activities; however, in 2008 (PG&E exception report generated) and in 2009 (no PG&E exception report generated) no company wide e-mail was sent to staff. USRB advised that PG&E RMP-06, Section 14.6 be more detailed to add other activities that currently were stated by PG&E staff as being performed, but don't appear to be captured under PG&E RMP-06, Section 14.6 (i.e., program metrics provided to senior management).