EXHIBIT 1

Pacific Gas and Electric Company®

Christopher P. Johns
President

77 Beale Street
San Francisco, CA 94105

Mailing Address
Mail Code B32
P.O. Box 770000
San Francisco, CA 94177

415.973.7000

January 31, 2013

Honorable Deborah A. P. Hersman
National Transportation Safety Board
490 L'Enfant Plaza, SW
Washington, DC 20594

Re: NTSB Safety Recommendations Status Update

Dear Chairman Hersman:

Pacific Gas and Electric Company (PG&E) continues to make substantial progress implementing the safety recommendations outlined by the NTSB's investigation of the September 2010 San Bruno pipeline accident. This status report provides details on the actions we are taking to assure public safety remains the company's highest priority.

In 2012, the NTSB evaluated PG&E's progress and closed four recommendations:

1. P-10-2: Search for Records

2. P-11-3: 911 Notifications

3. P-11-25: Emergency Response Procedures

4. P-11-28: Toxicology Testing

In this report, we are submitting three additional recommendations for closure consideration by the NTSB:

1. P-10-3: MAOP Validation

2. P-11-24: Work Clearance Procedures

3. P-11-31: Public Awareness Program Continuous Improvement

For recommendation P-10-3 (MAOP Validation), PG&E has completed the determination of the valid maximum allowable operating pressure (MAOP), based on the weakest section of the pipeline or component. The purpose of the MAOP validation is to ensure safe operation of natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas (HCA) that have not had a MAOP established through prior hydrostatic testing.

In total, MAOP validation was performed for all 2,088 miles of these transmission pipelines. In addition to completing NTSB Recommendation P-10-3, PG&E is validating all remaining transmission lines in non-HCAs by mid- 2013. In 2012, PG&E completed the MAOP validation of 4,199 miles of non-HCA pipelines.

For recommendation P-11-24 (Work Clearance Procedures), PG&E has completed the revision and issuance of work clearance procedures that include requirements for identifying the likelihood and consequences of failure associated with planned work. The development of contingency plans is now a part of this process. PG&E's new procedure ensures accurate and completed clearance forms and requires field crews, control room operators and individuals who have been assigned the clearance supervisor role to have complete knowledge of the intended work and written clearance procedure.

PG&E has completed recommendation P-11-31(Public Awareness Program Continuous Improvement) through the development and incorporation of written performance measurements and guidelines into our Public Awareness Plan (PAP) for evaluating the plan and for continuous program improvement. The primary objectives include awareness, damage prevention and emergency response readiness.

PG&E has also completed two portions of recommendation P-11-29 (Integrity Management Program): Revisions to PG&E's Risk Model and Risk Analysis Methodology.

Other recommendations with significant progress highlighted in the attachment include:

- (P-10-4)—In 2012, PG&E strength tested or verified an additional 202 miles for a total of 417 miles since 2011
- (P-11-2)—PG&E installed 46 valves in 2012 (for a total of 59 valves since 2010)
- (P-11-29)—In addition to revising the Integrity Management Risk Model and Risk Analysis Methodology, PG&E is continuing to revise other portions of its integrity management program

PG&E thanks the NTSB for both its continuing guidance and leadership as the company works to address the remaining safety recommendations.

Please contact me directly if you have any questions.

Sincerely,

Christopher P Johns

Christopher P. Johns

NTSB SAFETY RECOMMENDATIONS
UPDATE ON PG&E'S ACTIONS
JANUARY 23, 2013

P-10-3: MAOP Validation (Urgent)

Use the traceable, verifiable, and complete records located by implementation of Safety Recommendation P-10-2 (Urgent) to determine the valid maximum allowable operating pressure, based on the weakest section of the pipeline or component to ensure safe operation, of Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing.

Update for P-10-3

PG&E has completed MAOP validation for all pipelines in Class Locations 3 and 4 and in HCAs in Class Locations 1 and 2 in January 2012 as reported to the CPUC (*Attachment P-10-3 MAOP*). The MAOP validation was based on the weakest section of the pipeline or component in class 3 and 4 locations and class 1 and 2 HCAs that did not have a maximum allowable operating pressure established through prior hydrostatic testing.

In addition to completing NTSB Recommendation P-10-3, PG&E is validating all remaining transmission lines in non-HCAs and will be completed by mid- 2013. In 2012, PG&E completed the MAOP validation of 4,199 miles of non-HCA pipelines.

PG&E's "System and Method for Validating and Reporting Maximum Allowable Operating Pressure" is now available for commercial use for the North American Pipeline Industry.

P-10-4: Strength Testing

If you are unable to comply with Safety Recommendations P-10-2 (Urgent) and P-10-3 (Urgent) to accurately determine the maximum allowable operating pressure of Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing, determine the maximum allowable operating pressure with a spike test followed by a hydrostatic pressure test.

NTSB noted the following in its August 29, 2012 letter:

The NTSB notes PG&E's progress to address this issue, which includes (1) testing a total of about 39.5 miles of Line 132 (about 37 miles of which were tested in 2011), (2) conducting strength tests at 1.7 times the maximum allowable operating pressure plus a 10 percent spike test where possible, and (3) providing the CPUC with monthly reports on the status of its strength testing program. PG&E will continue action on this issue in two phases. Phase 1 includes testing or verifying records of 185 miles in 2012, 204 miles in 2013, and 158 miles in 2014. Phase 1 strength testing will address the following types of pipes:

- Pre-1970, low-frequency electric resistant welded, flash welded, single submerged arc welded, furnace butt welded, and lap welded pipe operating between 20 percent and 30 percent specified minimum yield strength (SMYS) in urban areas.
- All urban-area pipes operating at or above 30 percent SMYS, unless it has been scheduled for replacement or an adequate strength test for the pipe exists.

Phase 2, beginning in 2015, will include strength testing the following 1,700 additional miles of pipeline:

- All urban area pipes operating below 30 percent SMYS, unless it has been scheduled to be replaced or an adequate strength test for the pipe exists.
- All identified pipe not previously strength tested or replaced in Phase 1, which includes pipe located in Class 1 non-HCA, rural areas, unless an adequate pressure test exists for the pipe.

Pending completion of these efforts, Safety Recommendation P-l0-4 is classified "Open-Acceptable Response."

Update for P-10-4:

PG&E is continuing to perform hydrostatic testing or records verification of gas transmission pipeline sections designated as Priority 1 (those segments located within urban areas (Class 4, 3 and 2) operating above 30% without record of a pressure/strength test). In 2011, PG&E hydro tested (163.5 miles) or verified (50.9 miles) a total of 214.4 miles. In 2012, PG&E strength tested (175 miles) or verified (28 miles) an additional 202 miles. PG&E expects to complete pressure testing or records verification of a total of 783 miles by the end of 2014.

P-11-24: Work Clearance Procedures

Revise your work clearance procedures to include requirements for identifying the likelihood and consequences of failure associated with the planned work and for developing contingency plans.

NTSB noted the following in its August 29, 2012 letter:

The NTSB understands that PG&E is nearing completion of its work clearance procedure and will issue the revised procedure to all employees involved in the gas clearance process before the end of 2012. PG&E will also improve its clearance work processes by creating a distribution control center by the end of 2012. The center will oversee a uniform distribution clearance process nearly identical to the transmission process. In addition, PG&E's utility performance improvement team (Lean Six Sigma experts), in conjunction with gas control, engineering, and field maintenance, are now writing the distribution clearance process, which is expected to be completed in the third quarter of 2012. Pending completion of these efforts, Safety Recommendation P-11-24 is classified "Open-Acceptable Response."

Update for P-11-24:

PG&E's has completed the implementation of a revised work clearance procedure to include requirements for identifying the likelihood and consequences of failure associated with the planned work and developing contingency plans (*Attachment P-11-24 Clearance*).

PG&E has clarified and underscored the following in its revised clearance procedure:

- All sections and fields contained in the clearance form must be filled out completely.
- Individuals assigned the clearance supervisor role must have complete knowledge of the intended work and written clearance procedure before accepting this role.
- Field crew and control room operators must have clear and complete understanding of the scope and details of the clearance, including consequences and contingency plans. The understanding of the clearance will be gained through a crew tailboard and phone calls to the control room.

PG&E's Control Room Management process includes a change management procedure that requires commissioning and functional check out testing (end to end testing) of all components at the field level connected to SCADA. Commissioning and functional check out testing is now being completed for all new and rebuilt installations in conjunction with work clearance activities.

In addition to completing NTSB Recommendation P-11-24 for the gas transmission system, PG&E is implementing new electronic tools by the end of Q2 in 2013. In November 2012, the new Distribution Control Center opened for training in San Francisco; monitoring will begin in Q1 of 2013 and full operation is targeted for Q4 of 2013.

P-11-26: Supervisory Control and Data Acquisition System Tools

Equip your supervisory control and data acquisition system with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines.

NTSB noted the following in its August 29, 2012 letter:

The NTSB understands that PG&E is implementing three significant projects that will expand the current SCADA capability to predict and then manage abnormal events on the transmission and distribution system. These three projects are (1) implementation of an automated valve program, (2) OSIsoft PI Data Historian integration with SCADA and a graphic information system, and (3) creation of a distribution control center; they are to be the foundation of the broad initiative PG&E has undertaken to build a comprehensive controls framework to move from monitoring and reacting to one that is predictive and proactive. Pending completion of these efforts, Safety Recommendation P-11-26 is classified "Open-Acceptable Response."

Update for P-11-26:

PG&E is enhancing the SCADA information system to assist in recognizing and pinpointing the location of leaks, including line breaks by including additional information related to pipeline pressures, valve positions and gas flow rates as follows:

<u>Flow and Pressure Transmitters</u>

Upon completion of the Automated Valve Program as described in P-11-27 below, PG&E will have real-time knowledge of pipeline pressures at least every 5-8 miles on large diameter pipelines in Class 3 and 4 locations. PG&E plans to install 300 new pressure transducers and 30 new flow transducers by the end of 2014. As of December 2012, PG&E has installed 49 new pressure transducers and 3 flow transducers since October 2010.

<u>Leak Detection Tools</u>

Recommendations from a 3rd party evaluation of PG&E SCADA rupture detection capability are being evaluated for incorporation into PG&E's rupture detection strategy. The recommendations incorporate expansion of the use of Rate of Change (ROC) alarming and complex alarming involving the evaluation of combinations of data from multiple sites for more accurate rupture detection. Additionally, PG&E has initiated a pilot to utilize pipeline simulation software in conjunction with SCADA for large leak and rupture detection on a section of Class 3 backbone gas transmission pipeline to further evaluate the effectiveness.

<u>OSISoft PI Historian and Alarm Management</u>

PG&E has completed development of a software application to create a bridge between the SCADA alarm system and the OSISoft PI Historian to improve situational awareness and provide greater capability to track and analyze alarm information.[1] This platform will rapidly provide near real-time information to all areas of the Gas Operations organization, including engineering, planning, maintenance, and operations. This will provide better guidance and input for remote monitoring and controls, as well as for real-time operations.

---

[1] In late December 2011, PG&E completed a SCADA enhancement that prioritizes alarms for appropriate operator action upon activation. This SCADA modification project provides PG&E's operating team the capability to filter alarms based on priority, data type, and geographic location. Alarm priorities can now be configured based on four categories: Emergency, High, Medium, and Low

The new application allows operators, engineers and planners to query, sort, associate and record comments on SCADA system alarms. The new tool also provides a method for quickly accessing historical data trends related to each specific alarm, and includes automatic reporting features to aggregate alarm information into key performance indicators.

PG&E is using the new real-time OSIsoft PI Data Historian platform to support two large situational awareness screens. Billions of data records have been loaded into the OSIsoft PI Data Historian system representing more than a decade of historic SCADA information. New data is being added to the OSIsoft PI Data Historian system continuously, within seconds of being recorded in the SCADA system.

In addition to the SCADA tools described above, PG&E is also implementing other improvements described below:

SCADA Displays

PG&E is working with industry experts to establish new SCADA display and navigation design standards which meet the requirements of API 1165 (Graphic Standard, Recommended Practice for Pipeline SCADA Display) and has completed evaluation of new data presentation methods to meet the requirements of API 1165.[2] As a result of the work to date, new data presentation methods are being developed and deployed in the SCADA system. New display concepts will continue to be implemented for Gas Transmission displays with future SCADA upgrades.

Control Center

PG&E is continuing to move forward with building a new control center complex to co-locate transmission control, distribution control, gas dispatch, reliability planning and emergency response organizations. PG&E completed benchmarking activities; including site visits with more than a dozen major North American gas and electric utilities. PG&E has selected an external control room design consultant that will work with its facilities architect team to build out the new facility by April 2013.

The Transmission Control Center will be supported by a common SCADA system and the OSIsoft PI Data Historian system, an enhanced clearance process, and integration with the Gas Dispatch and Emergency Response organizations. PG&E's current SCADA system has been reviewed and will allow expansion to add several thousand monitoring and control points.

The Distribution Control Center opened for training in San Francisco in November 2012 and will continue to open in phases. Monitoring will begin in Q1 of 2013 and full operation is targeted for Q4 of 2013.

P-11-27: Automatic Shutoff and Remote Control Valves

Expedite the installation of automatic shutoff and remote control valves on transmission lines in high consequence areas in class 3 and 4 locations and space them at intervals that consider the factors listed in Title 49 Code of Federal Regulations 192.935(c).

NTSB noted the following in its August 29, 2012 letter:

The NTSB notes that PG&E is modernizing its pipeline system and using technology to help identify and respond to potential issues. PG&E expects to complete installation of the automatic shutoff valves and remote control valves by the end of 2014. Further, PG&E will enhance its SCADA information system by

[2] PG&E has completed work with human factors consultants developing a new SCADA visual coding design, including use of color, text and symbols in graphic displays to present alarm status and data quality.

including additional information related to pipeline pressures, valve positions, and gas flow rates. Pending completion of these efforts, Safety Recommendation P-11-27 is classified "Open-Acceptable Response."

Update for P-11-27:

PG&E's valve automation program goes significantly beyond current code requirements and current industry practices as detailed in our Valve Automation Plan filed with the CPUC on August 26, 2011 and included as part of the May 2012 status report. PG&E's Valve Automation Program is being implemented in two phases and will install or upgrade a total of 530 valves (210 valves as part of Phase 1 and 330 valves as part of Phase 2) with automated shutdown (ASV) or remote shutdown (RSV) capability on transmission pipeline in Class 3 and Class 4 locations. The transmission automated valve field site installations include new pressure and flow data being transmitted to the SCADA system providing additional information that will be utilized by new SCADA control tools and technologies to provide PG&E's Control Room operators with better situational awareness of pipeline conditions. Upon completion, PG&E will have real-time knowledge of pipeline pressures at least every 5-8 miles on large diameter pipelines in Class 3 and 4 areas.

Since 2010, PG&E has replaced, upgraded or automated a total of 59 valves through PSEP in the gas transmission system (13 valves in 2011 and 46 valves in 2012). Seventy-five valves are planned for 2013.

P-11-29: Integrity Management Program

Assess every aspect of your integrity management program, paying particular attention to the areas identified in this investigation, and implement a revised program that includes, at a minimum,

1) a revised risk model to reflect the Pacific Gas and Electric Company's actual recent experience data on leaks, failures, and incidents;
2) consideration of all defect and leak data for the life of each pipeline, including its construction, and risk analysis for similar or related segments to ensure that all applicable threats are adequately addressed;
3) a revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats; and
4) An improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment.

NTSB noted the following in its August 29, 2012 letter:

The NTSB notes that PG&E completed enhancements to its IM program by revising its risk model and integrity management program and by implementing information systems to ensure that all applicable threats are adequately addressed. PG&E planned to have converted its paper records and databases documenting gas transmission leak history into a single electronic database by mid-2012, including all documents designed to identify and report historical weld seam leaks. PG&E retained a consultant to provide an updated internal corrosion and a stress corrosion threat identification procedure to be integrated into PG&E's Transmission IM program in mid-2012 and to issue recommendations that PG&E plans to implement in 2012 and 2013. Pending completion of this work, Safety Recommendation P-11-29 is classified "Open-Acceptable Response."

Update for P-11-29:

1) **<u>Revised Risk Model</u>: A revised risk model to reflect the Pacific Gas and Electric Company's actual recent experience data on leaks, failures, and incidents**

   PG&E has completed the implementation of a revised risk model to reflect PG&E's actual recent experience data on leaks, failures and incidents. This work is performed at a minimum annually and was approved on March 26, 2012 (based upon updated HCA analysis and risk assessment performed on data collection through the end of 2011). This revision included changing the weighting of the risk factors of the existing threats in the risk algorithm to better reflect risk and threats related to long seam information and historical leak, failure and incident records that have been revealed through the extensive data collection efforts performed by the MAOP Validation efforts and feedback from PG&E's outside experts in risk assessment. *Attachment P-11-29 Risk Management* includes the documents that outline the changes made to implement the NTSB recommendations.

2) **Risk Analysis Considerations: Consideration of all defect and leak data for the life of each pipeline, including its construction, and risk analysis for similar or related segments to ensure that all applicable threats are adequately addressed**

After review and consideration of all defect and leak data for the life of each pipeline by PG&E's subject matter experts and Contractor, Det Norske Veritas (DNV), the revised risk model was approved by PG&E and the associated Risk Management Procedures were updated to reflect these changes. PG&E has developed its risk model to enhance consideration of stress corrosion cracking, internal corrosion, equipment and incorrect operations as threat terms in the overall risk algorithm and the results of the applied risk analysis will be published in the 1st quarter of 2013.

Centralized access to all data for PG&E's gas transmission pipeline assets, such as defect and leak data will be provided through the development of Mariner. The Mariner Project (referenced as GTAM in the May 2012 status report) is a four-year program designed to enhance the safety of PG&E's gas system by dramatically improving our ability to access verifiable, traceable and complete gas transmission pipeline information through core integrated systems. Mariner initiatives are focused on moving the Gas Operations organization away from reliance on paper records and towards robust electronic data management systems. The program will enhance safety by implementing improved capabilities in three key areas: work processes, data and records, and decision making.

In late 2012, PG&E uploaded the validated and spatially enabled Transmission Leak Forms data into GIS, which provided Integrity Management access to this data for use in assessing risks and the data will be available across the company. Over the long-term, the plan is to migrate this information from GIS to SAP to better align with PG&E's overall data management strategy. There will be a phased pilot that will start the migration of data to SAP in January 2013, and phased in over several months. PG&E's goal is to have all consolidated leak information migrated by June 2013.

3) **Revised Risk Analysis Methodology: A revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats**

PG&E has completed the implementation of a revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats. PG&E incorporated these procedures and analysis tools into its Integrity Management Program in 2012. PG&E's updated internal corrosion and stress corrosion cracking threat identification procedures were integrated into PG&E's Transmission Integrity Management Program during the 3rd quarter of 2012. *(Attachment P-11-29 Risk Management, RMP-16, Rev 0)*

In addition to the procedures that already existed for external corrosion, third party damage, incorrect operations, weather, and outside force and equipment threats, PG&E established new threat identification procedures for the following threats:

- Manufacturing
- Construction
- Internal Corrosion
- Stress Corrosion Cracking
- Interacting Threats (including cyclic fatigue)

PG&E will use this information as an input to developing its asset management plans, life cycle investments, and in implementation of its asset management plans.

4) **<u>Improved Self-Assessment:</u> An improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment.**

   Contractor, Det Norske Veritas (DNV), submitted their recommendations and PG&E is evaluating these recommendations for incorporation. The work is expected to be implemented by 2013.

P-11-30: Threat Assessment

Conduct threat assessments using the revised risk analysis methodology incorporated in your integrity management program, as recommended in Safety Recommendation P-11-29, and report the results of those assessments to the California Public Utilities Commission and the Pipeline and Hazardous Materials Safety Administration.

NTSB noted the following in its August 29, 2012 letter:

The NTSB notes that, when PG&E's overall risk model is updated to more expressly consider threats such as internal corrosion, stress corrosion cracking, fatigue, and interacting threats, the updated risk model will be included in future threat assessments and integrated into future baseline assessment plans. Pending completion of these efforts, Safety Recommendation P-11-30 is classified "Open-Acceptable Response."

Update for P-11-30:

PG&E's risk model was updated in collaboration with industry consultants and internal subject matter experts (P-11-29, 1). The updated risk model is targeted to be applied in 2013 for the 2012 Baseline Assessment Plan.

P-11-31: Public Awareness Program Continuous Improvement

Develop, and incorporate into your public awareness program, written performance measurements and guidelines for evaluating the plan and for continuous program improvement.

NTSB noted the following in its August 29, 2012 letter:

The NTSB notes that PG&E has developed written public awareness performance measurements and guidelines for evaluating the plan and for continuous improvement, in cooperation with the CPUC. In 2012, PG&E will further evaluate the effectiveness of its public awareness communication strategy based on its survey findings, as well as initiate an advertising campaign to reach its broad stakeholder audience. Pending completion of these efforts, Safety Recommendation P-11-31 is classified "Open-Acceptable Action."

Update for P-11-31:

PG&E has completed the development and incorporation of written performance measurements and guidelines into our Public Awareness Plan (PAP) *(Attachment P-11-31 Public Awareness)* for evaluating the plan and for continuous program improvement.

The primary objectives include awareness, damage prevention and emergency response readiness. On an annual basis the Public Awareness Administrator or designated resource will conduct a review and develop a written report that summarizes program implementation details, outreach summary and an assessment of message comprehension and understanding - a summary of stakeholder feedback collected during the year and details regarding any notable fluctuations compared to previous years. Stakeholder feedback may include:

- Survey data collected at meetings from emergency responders and excavators
- Stakeholder feedback collected through business reply cards
- Stakeholder feedback collected through phone surveys, mail surveys, online surveys, focus groups or stakeholder interviews
- Pre-Testing—reports from focus groups, employee interviews or online panels conducted to gauge message clarity and understandability of program materials.

Bottom-line results will document the number of third-party incidents during the previous year, near misses and any additional data tracked by Damage Prevention that is helpful in understanding excavator needs, issues and trends. Planned program changes for the upcoming year based on recommendations provided by the Public Awareness Program Committee, employees or vendors that support the program will also be included.

PG&E identified additional stakeholder audiences to receive targeted communications. As an example, 3,800 brochures were mailed to communicate with farmers to educate them about 811/ Call Before You Dig and to promote the awareness and purpose of pipeline markers. PG&E also initiated e-mail communications, phone calls and face-to-face meetings with more than 7,000 administrative and safety contacts at public and private schools near our gas distribution and transmission pipelines. Outreach to teachers and students reached 8,243 classrooms at 5,372 different schools and resulted in more than 29,500 visits to the web site. PG&E also delivered emergency response training to 666 CERT and NERT members and volunteers using new training and reference materials specifically developed for this audience.

P-11-25: Emergency Response – Additional Update

Although NTSB has closed Recommendation P-11-25: Emergency Response. PG&E would like to provide additional information regarding our efforts in this area. PG&E has developed a comprehensive emergency response procedure for large-scale emergencies on transmission lines, which identifies a single person in charge, outlines specific protocols and provides for drills and training. In the area of training, PG&E has continued to identify ways to strengthen controls and, in fact, after the May update, PG&E identified additional opportunities to better manage the Incident Command System (ICS) training. PG&E's May update stated that ICS training had been completed for employees that were Emergency Operations Center (EOC) participants. PG&E would like to clarify that ICS training is an on-going and recurring training to ensure EOC employees remain up to date on the emergency protocols and have regular opportunities to exercises the required skills and knowledge. PG&E has implemented more stringent controls to manage the training implementation which includes "profiling" employees with emergency management responsibilities to ensure training is completed timely and on an on-going basis.

EXHIBIT 2

PG&E Pipeline Safety Enhancement Plan (PSEP) Expedited Application Workshop

Tuesday March 26, 2013

CPUC, San Francisco

Agenda

- Purpose
- MAOP Validation prior to the Application
- Application Showing Information
- Impact on Validation
- Class 1 and 2 pipe
- Q&A

Purpose

Decision 12-12-030 addressing PG&E's PSEP,

- " ….we shall require PG&E to file an expedited application 30 days after the conclusion of its MAOP validation and records search work that includes an updated pipe segment database. The specific showing that PG&E will be required to provide in its application will be considered in a workshop to be held no later than 90 days from the effective date of this decision. We expect this expedited application to be limited in scope, but we believe that an expedited application will be a more appropriate means to review the submitted data than an advice letter." (p.115)
- Ordering Paragraph 11, Pacific Gas and Electric Company must file an application within 30 days after the completion of its Maximum Allowable Operating Pressure validation and records search to present the results of those efforts and update its Implementation Plan authorized revenue requirements and related budgets, consistent with this decision.

Process Prior to Application: MAOP Validation

Validate the MAOP for every gas transmission pipeline segment and component (feature).

- Reviewed in excess of 3.7 million documents to date
- MAOP Validation of all HCA pipeline segments (1,800 miles, Method 1) without prior strength test.
  - began in April 2011 and completed February 2012
- MAOP Validation of all remaining pipelines (4,950 miles)
  - forecast data review complete, April 2013
  - QA and data upload forecast complete, Summer 2013
- Level of effort (in excess of 250K person-days)

Process Prior to Application: MAOP Validation (continued)

- Segment MAOP's and the development of Pipeline Feature Lists (PFLs), data entry, and analysis will be completed April 2013.
- Before the MAOP Validation Project can be deemed "complete," PG&E must take the component level data from the PFLs and integrate the data with PG&E's enhanced GIS (Intrepid), and ensure geospatial alignment at the pipe segment level. PG&E expects to upload the data currently housed in PFLs into Intrepid during May 2013.
- Once the data are uploaded into Intrepid, PG&E plans to conduct a thorough Quality Assurance/Quality Control ("QA/QC") process before the data transfer can be deemed reliable.
- PG&E expects the QA/QC process to be completed June 2013.

Process Prior to Application: MAOP Validation (continued)

- After the MAOP Validation QA/QC is complete, the data must be transferred to the PSEP pipe segment database.
- Pipeline Modernization Decision Trees must be re-run using the updated data, and the results of that must be compared to the scope of work that PG&E forecasted in the original PSEP filing.
- Once PG&E has an updated forecast of capital and expense projects that result from running the new data through the Decision Trees, a new revenue requirement must be developed, and new gas rates must be consistent with the polices within D.12-12-030.
- PG&E expects the process of re-running the Decision Trees and developing new revenue requirements and rates for Phase 1 to require at least one month.
- Estimated Application Date: late August to mid-September 2013.

Validating PSEP Project Scopes

Project Validation is a multi step process. It involves:

- Data validation of pipeline properties from Pipeline Features Lists (PFL's) built by the Records Validation Team.
- PSEP Engineer transfers data from the PFL into the PSEP database.
- Updated pipeline segment Class Location and High Consequence Areas (HCA's) data is imported from GIS into the PSEP database.
- Updated pipeline segment attribute information is run through the PSEP decision tree.
- PSEP Action is input into the database.
- Field verifications of project (limits & location) including a review of existing land rights, permit requirements, construction feasibility, system capacity issues and any other Gas Accord V projects on the pipeline.
- Calculate cost responsibility (ratepayer & shareholder) based on CPUC PSEP Decision.

Application Showing/Information

- Updated PSEP Project Workpapers, Table 3-1 (Capital Expenditures and Expenses by Maintenance Activity Type (MAT)), Table 3-2 (Capital Expenditures by Maintenance Activity Type), Table 3-3 (Expenses by Maintenance Activity)
- Each table will list every PSEP proposed project, length, original cost estimate.
- PG&E will identify the PSEP action for each project following MAOP records validation. (e.g. Test, Replace, Phase 2, No Action)
- PG&E will identify change in project length, if any.
- PG&E will update project cost responsibility (ratepayer & shareholder) based on CPUC PSEP Decision.
- Updated Tables for Revenue Requirements, Cost Allocation and Rates for Phase 1 resulting from validation per CPUC decision.

Application Information (cont'd)

- An updated PSEP database (electronic file) with additional columns that will show validated:

•Pipe Diameter	•Test Date
•Yield Strength	•Test Medium
•Wall Thickness	•Test Duration
•Installation Date	•Test Witness
•Joint Efficiency Factor	•Test Pressure
•Seam Type	•Met Testing Req. at time of install
•Joint Type	•Met 49 CFR, Subpart J Test Req.
•HCA Status	•Met PSEP Criteria
•Class Location	•Decision Tree Outcome
•% SMYS	•Phase Deviation
•Segment Length	•Project Type
	•MAOP for Pipeline

Application Information (cont'd)

- Partial Screen Shot of Validated GIS information.

	A	B	C	DP	DQ	DR	DS	DT	DU	DV	DW	DX	DY	DZ	EA	EB	EC	ED	EE	EF
1				ion (DV) Of GIS Data																
2	OBJE	ROUTE	SEGMEI	DVChg_	OD_PFL	INS_JOB_I	YR_INSTA_	FOOTA	CL/	JNTE	GIRTH	LONGSEAM_R	JOINT_TY_	SMYS_F	MOP	W_THI(	DV_TEST_	TEST_PRE	MEDIUM_I	TEST_DUR_F
117	1115	108	162.2		16.000	38100	1/1/1930	90	3	0.8	Unkno\	AOS	BellSpigot	33000	490	0.2500	No Test	No Test	No Test	No Test
118	1116	108	162.3		16.000	38100	1/1/1930	5	3	0.8	Unkno\	AOS	BBCR	33000	490	0.2500	5/28/1970	925	W	21
119	1117	108	162.4		16.000	38100	1/1/1930	4	3	0.8	Unkno\	AOS	BBCR	33000	490	0.2500	5/28/1970	925	W	21
120	1118	108	162.6		16.000	38100	1/1/1930	180	3	0.8	Unkno\	AOS	BBCR	33000	490	0.2500	5/28/1970	925	W	21
121	1119	108	163		16.000	38100	1/1/1930	1776	3	0.8	Unkno\	AOS	BBCR	33000	490	0.2500	5/28/1970	925	W	21
122	1120	108	163.2		16.000	174114	2/1/1970	55	3	1	Unkno\	UNK	Unknown	42000	490	0.2500	5/28/1970	925	W	21
123	1121	108	163.3		16.000	174114	2/1/1970	33	3	1	Unkno\	UNK	Unknown	42000	490	0.2500	5/28/1970	925	W	21
124	1122	108	163.6		16.000	38100	1/1/1930	211	3	0.8	Unkno\	AOS	BBCR	33000	490	0.2500	5/28/1970	925	W	21
125	1123	108	164		16.000	38100	1/1/1930	1025	3	0.8	Unkno\	AOS	BBCR	33000	490	0.2500	5/28/1970	925	W	21
126	1124	108	164.3		16.000	174114	2/11/1970	116	3	1	Unkno\	ERW	Unknown	30000	490	0.2500	5/28/1970	925	W	21
127	1125	108	165		16.000	119743	8/24/1952	310	3	1	Unkno\	ERW	Unknown	30000	490	0.2500	5/28/1970	925	W	21
128	1126	108	165.1		16.000	38100	1/1/1930	1416	3	0.8	Unkno\	AOS	BBCR	33000	490	0.2500	5/28/1970	925	W	21
129	1127	108	165.2		16.000	38100	1/1/1930	77	3	0.8	Unkno\	AOS	BBCR	33000	490	0.2500	5/28/1970	925	W	21
130	1128	108	165.3		16.000	4597217	6/25/1987	357	3	1	Unkno\	ERW	Unknown	42000	490	0.3750	6/24/1987	1250	W	8.3
131	1129	108	166		16.000	4597217	6/25/1987		3	1	Unkno\	ERW	Unknown	42000	490	0.3750	6/24/1987	1250	W	8.3
132	1130	108	166.3		16.000	4597217	6/25/1987	5547	3	1	Unkno\	ERW	Unknown	42000	490	0.3750	6/24/1987	1250	W	8.3
133	1131	108	167		16.000	4597217	6/25/1987	1913	2	1	Unkno\	ERW	Unknown	42000	490	0.3750	6/24/1987	1250	W	8.3
134	1132	108	167.1		16.000	30604391	9/29/2008	29	2	1	Unkno\	SMLS	Unknown	35000	490	0.3750	9/8/2008	1100	W	8.3

Application Information (cont'd)

- Updated data will resolve data in the "MAOPrec430" data field (complete, incomplete, partial and blank).
- Updated database will include test date, test pressure, test duration, test media, installation date.
- Given the millions of documents involved in the MAOP determination process, copies of detailed documentation confirming pipe specs and pressure tests will not be included. Instead, stakeholders will be provided access to the Records database to view these documents onsite.
- Segments that have dropped out of Phase 1 due to records validation will be noted.
- A description of "Other, High Priority Projects" that were not identified in the original filing but may be done in Phase 1, if any.

Impact of Validation on Phase 1

Per D.12-12-030, to the extent that validation impacts work proposed in Phase 1, then it will be described in the Application. Some examples include:

- The gap between segments to be tested is short (less than 1 mile for hydrotest and there are no other complicating issues).
- The affected segments are adjacent to phase 1 work, and addressing other adjacent untested segments is economical at this time.
- The pipeline is to be retired so all segments within the section to be retired are affected.
- The boundaries of a pressure test may be extended to avoid impacting an environmentally sensitive area.

Impact of Validation on Phase 1

Decision 12-12-030 addressing PG&E's PSEP

- "Accordingly, the general rule is that pipeline segments in Class 1 or 2 locations will not be included in Phase 1. We recognize exceptions to this general rule where, for sound engineering or economic reasons, pipeline segments not located in the priority locations should nevertheless be included in Phase 1. Pipeline segments adjacent to priority locations logically fit within such exceptions. Thus, we find that to the extent a pipeline segment is located in a Class 1 or 2 area but is adjacent to Class 3 or 4 locations, PG&E properly included the Class 1 or 2 segments in Phase 1...." (p.67)

Class 1 & 2 Pipe

How has PG&E addressed Class 1 & 2 pipe segments in response to the CPUC Decision?

- PG&E will review the pipeline replacement and strength testing projects for any projects which consisted entirely of Class 1 and 2 non-HCA pipe in Phase 1. Projects will be reviewed and removed, as appropriate, through Application.
- Engineering judgment and Phase deviation codes in the PSEP database to define which Class 1, Class 2 pipe segments and segments with prior test records get included within a project scope.
- Project Examples.

Questions?