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Christopher P. Johns
President

February 28, 2012

The Honorable Jerry Hill
Member of the State Assembly
State Capitol, Room 3160
Sacramento, CA 95814

Dear Assemblymember Hill:

Since the tragic accident in San Bruno, PG&E's gas operations and gas transmission system have appropriately come under great scrutiny from federal and state regulatory agencies, independent third parties and our many stakeholders, including our customers. But no one has turned a more critical eye toward our operations, systems and culture than we have at PG&E.

We take very seriously any questions raised about the safety of our pipeline system and the quality of our ongoing hydrotesting program, which is why we immediately investigated the concerns raised in testimony given by Marshall Worland and Mike Mikich to the California Public Utilities Commission in the Order Instituting Rulemaking R.11-02-019 and closely cooperated with the parallel inquiry conducted by the Commission's Consumer Protection and Safety Division. The result of our investigation is that, in substance and in spirit, PG&E found the allegations made by Mr. Worland and Mr. Mikich to have no merit whatsoever.

The findings of our investigation are addressed in the attached appendix as part of the responses prepared by our gas team to each of the questions you raised in your recent letter to PG&E. But before reviewing that information, please allow me to provide some valuable context on the progress PG&E has made to date to improve the safety and integrity of our gas transmission system and the performance of our gas operations.

PG&E is now engaged in a pipeline testing and records verification effort that is unprecedented in our industry in both its scope and rigor. In 2011 alone, we hydrotested more than 163 miles of our transmission system; in early 2012, we also finished validating the operating pressure for all of our pipes in densely populated areas—more than 2,000 miles in all. In 2012 we plan to hydrotest 185 miles of our transmission system, modify our system to allow inline inspections on just under 80 additional miles, replace 39 miles of pipe and automate 46 valves in 16 locations across our service area.

To provide transparency in our hydrostatic testing program, we supplied monthly updates to the CPUC and the public in 2011, in addition to extending regular invitations to the media, regulators and others to observe our field work. We embarked on an aggressive outreach campaign to inform our customers of the work being done in the communities we serve.

To verify that all of our 2011 hydrostatic testing work met or exceeded industry standards, PG&E used a detailed inspection and certification process, performed by IBEW-represented employees, to assure our standards were met. Generally, when hydrostatic testing work was conducted by experienced construction contractors, and not PG&E employees, PG&E retained Canus Corporation to inspect their work and validate that it met PG&E standards.

The result of these extensive quality validation efforts—as well as the expertise of our welders, who undergo three-year 6,000 hour state-approved apprenticeship and training programs and are retested every six months to ensure their skills remain qualified—is that we have the utmost confidence in the integrity of the pipeline work that we performed and are performing across our service area.

Additionally, PG&E has made progress in moving our culture toward one of more openness and accountability, as demonstrated by the recent action taken by a number of our gas operations employees who identified a gap in our leak survey work. Their actions, which facilitated work to correct the omission as quickly as possible, were publicly praised by Nick Stavropoulos, our Executive Vice President of Gas Operations, as well as by multiple members of the Commission.

Thank you for the opportunity to address your concerns and provide an update on the progress we've made in our gas operations. If you would like additional information on these or any other questions about our commitment to safety, integrity and transparency in all of our operations, please feel free to contact me.

Sincerely,

Christopher P. Johns

Christopher P. Johns

Attachment

APPENDIX TO FEBRUARY 23, 2012 LETTER FROM
CHRISTOPHER P. JOHNS TO
THE HONORABLE JERRY HILL

1. **What is PG&E's process by which new information regarding the pipes' condition or any other pertinent information is recorded and integrated into existing records? Who decides what information will become part of the record?**

   PG&E's standards and procedures require the completion of inspection forms when gas transmission pipelines are field tested and repaired due to conditions, such as leaks, corrosion, damage by third party, weld failures or other causes. These forms require the crew to describe not only the condition of the respective gas assets but also the details associated with the repairs.

   The completed forms are submitted to the gas transmission mapping group which is responsible for updating PG&E's Geographical Information System (GIS) with all applicable information for gas transmission assets.

2. **How is new information integrated into the decision tree used in the Implementation Plan? Who makes this decision?**

   For all work performed under the Pipeline Safety Enhancement Plan (PSEP) PG&E will update every job file to reflect the most recent information gathered from the MAOP Validation process as part of the final engineering of each project. The pipeline projects we pursue under the PSEP will be based upon the Pipeline Modernization Decision Tree and the most current and accurate data about the pipeline characteristics, as verified through the MAOP Validation process which is now complete for all HCA pipeline segments and pipeline information gathered during other pipeline work. The PSEP engineering team reviews all of the new information prior to final engineering release. If the new data indicates a different action should be taken (e.g. replace pipe instead of a strength test) the change is made. The PSEP Program Sponsor and Vice President of Gas Transmission and Maintenance and Construction makes the decision on how the new information is integrated into the Decision Tree.

3. **How does new information factor into threat identification, risk assessment, and ongoing maintenance? Is PG&E using this opportunity, with exposed pipe, to perform work associated with its integrity management and risk management programs?**

   Once a hydrotest or pipeline replacement project is completed, the job file is sent to PG&E's gas transmission mapping group. In the case of a hydrotest or pipeline replacement project, the job file includes the applicable strength test pressure reports, pipe replacement section properties and all inspection forms. The mapping group then updates PG&E's GIS with all applicable test and pipe specification information and posts the inspection forms.

   The newly updated GIS information is then used by the Transmission Integrity Management (TIMP) group during the annual update of PG&E's Baseline Integrity Assessment Plan. This process evaluates all transmission pipeline segments for the presence of specific threats (as identified in ASME B31.8S), their associated risk and then establishes their schedule for assessment or re-assessment.

Finally, the information gathered is utilized by the TIMP implementation teams when performing pre-assessments on pipeline segments scheduled for inspection at which time the threat identification is confirmed or modified and the correct assessment tool or tools are being utilized for the applicable active threats.

4. **When employees are alerted of a potential threat, how are they to respond?**

   This is a broad question; however, as a general matter when an employee identifies a potential integrity related concern on a gas transmission asset, he or she should immediately notify the assigned Pipeline Engineer for the geographic area (or engineer on-call). For example, where reduced wall thickness, corrosion pits, dents or mechanical damage are observed, the responsible Pipeline Engineer is alerted. The Pipeline Engineer evaluates the defect and determines the appropriate response. In the specific case of corrosion, the Pipeline Engineer will utilize an industry recognized remaining strength calculation method to determine the remaining strength in the pipeline. If action is needed, the responses can range from an immediate lowering of the pipeline pressure, to installing repair sleeves, or replacing the pipe depending on the severity of the defect.

   As an example, during an excavation conducted as part of the Records Verification & MAOP Validation Project in June, 2011, to verify the longitudinal seam type of a 34" section of pipe, a linear indication was identified in the pipe fabrication seam as part of the radiograph examination. This finding resulted in an immediate notification to the Pipeline Engineer and it was decided that approximately 10 feet of pipe should be replaced. Since the pipe replacement was estimated to take several days to complete, PG&E immediately reduced the pipeline's operating pressure to provide an additional margin of safety until the pipeline segment was removed.

5. **Mr. Mikich seems to indicate that PG&E is simply "patching" pipeline segments that would otherwise fail hydrotest even when that might not be the safest approach. Is this true?**

   This is not true. PG&E is employing the highest industry standards in its hydrotest program, as well as its other gas transmission programs. Mr. Mikich's role was to perform welding services and consequently he was not exposed to the engineering evaluations and repair methods PG&E utilized to assess existing pipeline conditions. The hydrostatic test team was very diligent and will continue this diligence in addressing issues with the condition of piping and valves and other appurtenances that are identified in the process of engineering, unearthing pipelines, or operating valves during the hydrostatic tests.

   In Palo Alto, while conducting a hydrostatic test, PG&E found a small pocket of external corrosion near a test head location. The corrosion pit was approximately 50% of the pipe wall thickness. This small area of corrosion was repaired with a 3 foot sleeve per PG&E's repair standards which are consistent with industry standards. Mr. Mikich inaccurately states that a 6 foot sleeve was used and implies that the corrosion was more wide spread than was actually observed. During the hydrostatic test of this section of pipe, a small pipeline leak occurred. PG&E located the leak. The leak occurred at an isolated corrosion pit, with a 7 millimeter diameter hole. This failure occurred during the hydro test at a pressure in excess of the pipeline

MAOP. The corrosion pit was located several miles away from the test head location referenced above. This 7 mm pit was repaired with a two-foot sleeve. PG&E was transparent regarding the entire process to the media and our regulators from the initial findings until the section of pipe was repaired. Both of these sections of pipe with the installed sleeves were hydrostatically tested to about 1.6 times MAOP and no further issues were found. PG&E views the discovery of these types of isolated anomalies as a success; these are the type of issues PG&E wants to find and repair while conducting hydrostatic testing.

Mr. Mikich also discusses in his testimony the patches that are installed on Line 153. These were made in the early 1950's to allow for the installation of a communication cable inside the pipeline. The communication cable was decommissioned decades ago but never removed. These patches were viewed internally with a camera and their locations were marked. The stub-ins that Mr. Mikich describes were also part of this telecommunications cable to allow the cable to exit and re-enter the pipe around valves. Prior to conducting the hydrostatic test, PG&E removed each of these patches and stub-ins by replacing this section of pipe with new pipe. PG&E also removed all of the telecommunications cable in that section of pipeline. Mr. Mikich's description of the patch construction was not accurate. The patch was actually the original cut out section of pipe welded back into place and then covered with a pipeline sleeve which was welded to the pipe. Mr. Mikich may have seen the internal camera photos and speculated that it was a plate welded to the outside of the pipe but this was not the case. This design was safe. Even so, the pipe sections with the patches were removed to facilitate the removal of the cable prior to testing. The removed sections were replaced with new pipe.

6. **According to testimony given at the NTSB investigatory hearings one of the limitations of pressure testing is that is only identifies the most severe of defects and may not indicate if other defects exist. How does PG&E deal with pipe that is corroded or that might have welding deficiencies if the pipe segment passes a hydrotest?**

A hydrostatic test is one of several effective tools the industry has available to test certain aspects of the integrity of a gas pipeline. Hydrostatic testing can be used to evaluate possible threats activated by internal pressure and cyclic fatigue, such as corrosion, longitudinal seams defects, and mechanical damage. This type of strength testing does not necessarily put sufficient stress on girth welds to identify every welding deficiency that might exist because girth welds are less susceptible to internal pressure hoop stress. Girth weld threats are generally activated by ground movement such as liquefaction, slope instability and differential settlement.

PG&E's integrity management program employs other inspection methods beyond hydrostatic testing and other analytic tools to evaluate the potential for ground movement, external corrosion and threats posed on girth welds. In-line inspection tools, direct assessments and other test methods can be employed in appropriate circumstances to attempt to identify the location of these threats to allow for inspection and possible repairs. Leak surveys and pipeline patrols can also be used as another layer of monitoring for these types of threats.

7. **What are PG&E's criteria for determining whether a pipe is safe?**

We assume you are asking about PG&E's criteria to evaluate exposed defects and the corresponding repair methods. PG&E gathers data every time a pipeline is exposed. If there is reduced wall thickness, corrosion pits, dents or mechanical damage observed, the responsible Pipeline Engineer is alerted. The Pipeline Engineer evaluates the defect and determines the appropriate response. In the specific case of corrosion, the Pipeline Engineer will utilize a computer program, to determine the remaining strength in the pipeline. The responses will range from an immediate lowering in pressure, to installing repair sleeves, to ultimately replacing pipe depending on the severity of the defect.

8. **The NTSB's final San Bruno Accident Report outlines one of PG&E's deficiencies was the utility's "poor quality control during pipe installation." The testimony presented by Mr. Worland and Mr. Mikich seems to indicate this problem still plagues the company. What is PG&E doing to ensure that both the utility and its contractors are following industry standards for the work being done on pipes that are hydrotested?**

We have taken their claims seriously and investigated. We carefully reviewed the ten hydrostatic test projects that Mr. Mikich and Mr. Worland were either involved with based on time records or they mention in their testimony. The records show that every weld completed had an x-ray and that each x-ray passed inspection by a certified independent x-ray technician. Also, each weld was inspected by a qualified weld inspector. PG&E believes the work was done to industry standards and is safe.

Generally, PG&E did not ask CANUS to inspect PG&E welding work on these projects because PG&E was utilizing its own supervision and inspection process with IBEW employees to assure that PG&E standards were met. CANUS was primarily directed to make sure that the construction contractors were conducting the hydrostatic tests in accordance with PG&E's standards and construction drawings and instructions. Accordingly, as a practical matter, when welding work was scheduled at a specific job site, the supervisor would schedule weld inspectors to inspect those welds consistent with this approach. However, there never was an express policy, in the contract or otherwise, that prohibited a PG&E inspector from inspecting a contractor weld or vice versa. In fact, the CANUS contract provided that contractor qualified weld inspectors could inspect any weld on the job site (e.g. PG&E or contractor). Given the number of separate hydrotests, the number of separate job sites, and the number of welds at each site, there were instances where a CANUS inspector inspected a PG&E weld, but we have found no record where Mr. Worland inspected a PG&E weld.

PG&E has its own supervision and inspection process to assure that PG&E standards are met. PG&E welders undergo three-year, 6,000 hour state-approved apprenticeship and training programs and are retested every six months to ensure their skills remain qualified.