BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms.	Rulemaking 11-02-019 (Filed February 24, 2011)

TECHNICAL REPORT OF THE CONSUMER PROTECTION AND SAFETY DIVISION REGARDING PACIFIC GAS AND ELECTRIC COMPANY'S PIPELINE SAFETY ENHANCEMENT PLAN

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The Consumer Protection and Safety Division (CPSD) worked in collaboration with Jacobs Consultancy (Jacobs) in the preparation of the attached report, Assessment of Pacific Gas & Electric Company's Pipeline Safety Enhancement Plan.

The Pacific Gas and Electric Company (PG&E) Pipeline Safety Enhancement Plan (PSEP) primarily utilizes decision trees as models to help in identifying and prioritizing projects for pressure testing or replacement activities. PG&E also utilizes decision trees to determine the placement and type of automated valve to install on certain transmission pipelines in its system in order to be able to quickly and remotely control the flow of gas in the event a breach in the integrity of a transmission pipeline. PG&E's decision trees also consider valve placement on transmission pipeline segments in areas where a pipeline located along an earthquake fault, could be ruptured in a potential seismic event. The decision tree framework makes an appropriate assessment of risks, and logically identifies when to replace versus pressure test segments and where to place remote control and automatic shutoff valves (collectively referred to as automated valves).

Pipeline Modernization Plan

CPSD's review found that PG&E's PSEP provides a consistent, repeatable, and well defined mechanism for identifying, planning, and estimating projects to test or replace pipeline segments which have not been adequately pressure tested to current safety testing standards, as codified in Part 49, Code of Federal Regulations, Part 192 (49 CFR, Part 192) subpart J. However, as noted in the attached report, much of the data PG&E utilizes in its models is derived from the Company's current geographic Information system (GIS).

CPSD's investigation of the tragic September 9, 2010 incident in San Bruno very early placed the accuracy of pipeline information in GIS into question. Since then, much has been done by PG&E to implement efforts to validate actual transmission pipeline data for components installed on all pipeline segments. These validation efforts, which do not rely on existing GIS data, are being conducted through review of pressure test documentation, as-built construction records and/or other verifiable, traceable, and accurate data.

Although PG&E's validation efforts are underway, and they are continuing to identify records that help improve the accuracy of PG&E's transmission pipeline related information, exact timetables, by when validation efforts will be completed, is not certain. Confirmation of data for some segments may allow projects prioritized for testing or replacement by the decision tree models to be removed or placed in a lower priority, while the opposite may occur for other segments. There is also extreme uncertainty in maintaining the scheduling for projects and assuring that project costs remain within estimates.

Based on all issues discussed above, although the decision trees properly select segments for replacement versus pressure testing and establish a logical prioritization of that work, CPSD cannot establish whether each segment has been properly placed or prioritized because the resulting output from the decision trees is only as good as the accuracy of the data which is put through the model. In addition, neither CPSD, nor its consultant, were able to conduct a test of the decision tree process because certain information required to verify compliance with the decision tree framework was not available.

Therefore, CPSD recommends that the CPUC perform audits on a quarterly basis to confirm that PG&E continues to update its PSEP and decision trees to reflect new knowledge gained about its pipeline facilities and that the models continue to be re-run, using the most updated pipeline information.

Valve Automation Plan

As noted above, CPSD believes PG&E's approach to determining where automated valves should be installed to reduce the consequences of a major pipeline breach is sound. The number of automated valves to be installed under PG&E's PSEP, however, could be considered high in comparison to the spacing proposed for such valves in federal legislation now under consideration. As proposed, PG&E's PSEP relies primarily on remote control valves (RCVs), rather than automatic shut-off valves (ASVs).

In the absence of existing regulations, or specific historical studies defining acceptable automated valve spacing, PG&E's proposed spacing of RCVs is intended to limit gas flow into areas to approximately ten minutes after the last valve necessary to isolate the breached segment closes, assuming the segments are operating at their maximum allowable pressures. The time period to stop gas flow could be shorter or longer depending on the operating pressure at the time of the breach. Also, the time to completely evacuate gas from the line could be longer if the breach results in a partial, but not a full, break in the line.

The approximate time of ten minutes to evacuate the line of gas is independent of the amount of time it would take an operator to identify, determine, and act to close the particular valves necessary to isolate a breached segment. CPSD believes that the additional data sensing points PG&E proposes to install are necessary to enable automated processes to help operators quickly and accurately determine the location of a breach. However, even with this additional information, CPSD believes it could take an operator 10-15 minutes to make the decision to shut a RCV. This means that for a full breach, the time to completely stop the flow of gas would be approximately 25-30 minutes.

Based on general concerns expressed by first responders, CPSD believes that first responders would consider 30 minutes to completely stop gas flow as being reasonable. Additional data sensing points would provide PG&E with the ability to calculate flow conditions and gas evacuation times, in real time, and be able convey this information to first responders. Such information, first responders have communicated to CPSD, is information that is crucial to allow them to more effectively plan their actions in response to a pipeline event.

As noted in the attached report, automated valves can generally be configured to operate in two modes: ASV or RCV. The most significant concern with ASVs is their potential, albeit very low, to falsely close. It is for this reason that PG&E's PSEP proposes that almost all locations where valves are to be automated through retrofit of existing valves, or through the installation of new valves, to use valves in RCV mode. However, PG&E's proposed number of automated valve installations could potentially be decreased if it installs ASVs at less frequent spacing than that at which it now proposes to install RCVs.

As an example, a separation of 16 miles for ASV valves, versus a spacing of 8 miles for RCV valves, entails twice the amount of gas that would have to be evacuated through a rupture location. However, the time to evacuate the gas from the two ASVs would generally be the same as for RCVs spaced at half the separation. This is because an ASV begins to close on its own, and without direction from an operator, once its trip parameters are reached and maintained. Eliminating the time needed for an operator to make a determination entails a time difference of approximately 10-15 minutes. The same 10-15 minutes in which gas would have continued to flow pending an operator's determination would then be used to evacuate the gas from a longer section (i.e., 16 miles vs. 8 miles) of pipeline.

There is no denying that significant gas disruptions, and customer inconvenience, can occur from a false closure of an ASV. These conditions are compounded if a false trip occurs under high gas demand conditions, which are the very types of conditions that raise the risk of an ASV falsely closing. Because PG&E does not have sufficient historical, real time, flow data for its transmission system, it is not possible for CPSD to identify locations where ASVs could be installed without triggering potential for ASVs to falsely close. Unfortunately, as noted earlier, there are no known studies or examples which provide for such insight at this stage.

In the absence of guidance from previous studies or models of installations of similar scope to that now being pursued by PG&E, CPSD finds it difficult to quantify the precise numbers of telemetry installations and new or retrofitted automated valves that are required. The absence of any PG&E benefit-to-cost studies for the proposed number of installations further limits our ability to form a definitive opinion. Nonetheless, there is a clear need to have more protection than now exists.

CPSD recommends that the CPUC allow PG&E to proceed with the installation of telemetry facilities at all locations as planned. CPSD believes these readings are crucial because they allow for pin-pointing failure locations and will assist in first response efforts to any failure events. If the CPUC is willing to accept some risk of false closure, the number of automated valves proposed in the PSEP could be reduced with the installation of ASVs, at intervals longer than those being proposed by PG&E for RCV installations, and still ensure that gas flow is stopped within 30 minutes of a full breach of the pipeline. If the CPUC decides that the risk of false closure is too high, CPSD believes PG&E's PSEP valve program will allow gas flow from a full breach to be extinguished within 30 minutes from the time of the breach, provided that PG&E closes all RCVs necessary to isolate the affected section of pipe, within 15 minutes of the breach.