Pacific Gas and Electric Company®

Brian K. Cherry
Vice President
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

415.973.4977
Fax: 415.973.7226

October 25, 2010

Paul Clanon, Executive Director
California Public Utilities Commission
505 Van Ness
San Francisco, CA 94102-3298

Re: Updates on Natural Gas Transmission System

Dear Mr. Clanon:

In your letters to PG&E dated September 13, 2010, September 17, 2010, and October 15, 2010 and in the Commission's Resolution L-403 adopted on September 23, 2010, PG&E was directed to take several actions with respect to its natural gas transmission pipelines. This letter transmits PG&E's response to several directives, indicated below, as issued in your letters and incorporated into Resolution L-403:

Attachment 1: Assessment of gas transmission pipelines in the San Bruno area.
Item 2 in the September 13, 2010 letter and Ordering Paragraph 11 in Resolution L-403.

Attachment 2: Preliminary report on the replacement or retrofit of manually operated valves with automatically or remotely controlled valves on PG&E gas transmission pipelines.
Item 11 in the September 13, 2010 letter, Item 7 in the September 17, 2010 letter, and Ordering Paragraph 21 in Resolution L-403.

Attachment 3: Accelerated gas system survey initial report.
Item 3 in the September 13, 2010 letter and Ordering Paragraph 12 in Resolution L-403.

Attachment 4: Curtailment plans.
Items 1, 2, and 3 in the October 15, 2010 letter.

Please contact me should you have any questions.

Sincerely,

Brian K. Cherry
VP Regulatory Relations

cc: Michael R. Peevey, President
Timothy A. Simon, Commissioner
Dian M. Grueneich, Commissioner
John A. Bohn, Commissioner
Nancy Ryan, Commissioner
Julie Fitch, Energy Division
Richard Clark, Consumer Protection Safety Division
Julie Halligan, Consumer Protection Safety Division
Frank Lindh, General Counsel
Harvey Y. Morris, Legal Division
Patrick S. Berdge, Legal Division
Joe Como, Division of Ratepayer Advocates

ATTACHMENT 1

ASSESSMENT OF GAS TRANSMISSION PIPELINES IN THE SAN BRUNO AREA

The letter from Paul Clanon to PG&E dated September 13, 2010 (Item 2) and Ordering Paragraph 11 of Resolution L-403 directed PG&E to conduct an integrity assessment of all gas facilities in the impacted area.

PG&E responded on September 20, 2010, describing some of the immediate steps it had undertaken, including an accelerated survey of the gas transmission lines in San Bruno and the distribution system in and around the impacted San Bruno neighborhood. PG&E also committed to conduct instrument surveys to provide a more detailed assessment of the pipe and pipeline coating for all transmission mains in San Bruno.

On September 23, 2010, PG&E stated that it would perform instrument surveys over all gas transmission mains in San Bruno using Close Interval Survey (CIS), Direct Current Voltage Gradient (DCVG) and Pipeline Current Mapper (PCM) tools.

PG&E has completed this survey. It includes the 15.93 miles of transmission pipeline within 26 high consequence areas (HCAs), as well as some non-HCA transmission pipelines. The surveys included the portions of Lines 101, 109 and 132 within and extending outside the city bounds of San Bruno, as well as all distribution feeder mains. The CIS was performed at 10-foot intervals to ascertain if any potential cathodic protection deficiencies exist on the pipe. The DCVG survey was performed to identify any coating anomalies. The PCM survey was performed at 25-foot intervals along the pipeline to measure the depth profile of the pipelines.

PG&E did not identify during the survey any integrity issues that required immediate repair. The survey found one indication of a potential contact between the transmission line and the casing on Line 101, where Line 101 intersects with Highway 101.[1] Consistent with existing practices, PG&E will excavate the area immediately surrounding

[1] A casing is a larger pipe surrounding the pipeline carrying gas. Casings are not pressurized. They were required by CalTrans, railroad companies and other agencies when pipelines were built across their right-of-ways. Casings are designed to be separated from the pipeline by spacers and end seals to keep water and dirt out of the space between the pipe and the outer casing. Over time, they can shift in the ground or dirt and water can enter the casing; either scenario can lead to casing contact with the pipeline.

the detected casing/pipeline contact, conduct a visual examination to confirm contact, and take remedial actions if necessary.[2]

[2] Remedial action includes eliminating the contact or creating an inert (noncorrosive) environment.

ATTACHMENT 2

PRELIMINARY REPORT ON THE REPLACEMENT OR RETROFIT OF MANUALLY OPERATED VALVES WITH AUTOMATICALLY OR REMOTELY CONTROLLED VALVES ON PG&E GAS TRANSMISSION PIPELINES

The letters from Paul Clanon to PG&E, dated September 13, 2010 (Item 11) and September 17, 2010 (Item 7), and Ordering Paragraph 21 of Resolution L-403 directed PG&E to conduct a review of gas transmission line valve locations in order to determine a list of locations at which manual valves could be replaced by remotely-operated or automatic shut-off valves, an estimate of the costs of such replacement valves, and a description of the types of valves commercially available.

PG&E responded on September 20, 2010, affirming its commitment to conduct the review and provide the list and estimates requested.

SUMMARY

What follows is PG&E's preliminary report regarding the replacement or retrofit of manually operated valves with remotely controlled or automatic shut-off valves on its gas transmission system. PG&E proposes that this preliminary analysis be included in its Pipeline 2020 program and be reviewed by the CPUC and a third-party natural gas transmission expert in order to validate the analysis. Based on our preliminary analysis, PG&E estimates there are approximately 300 manual valves on over 565 miles of pipeline that should be further evaluated for potential replacement or retrofit.

There currently are no specific regulations governing the use of automated valves. As part of PG&E's Pipeline 2020 program, PG&E has engaged a third-party firm to review these preliminary conclusions and to provide recommendations in connection with the more detailed plan that PG&E will file with the Commission for its consideration. The firm will examine the specific requirements of PG&E's system, benchmark PG&E's practices against those of other pipeline operators, and assess the potential to replace or retrofit manually operated valves with remotely operated or automatic shut-off valves, as well as assess adding new valves. It will also identify associated enhancements to gas system operations, including protocols, training and system upgrades to enable effective use of the valve technology.

This study has begun and is expected to be completed by the end of the second quarter of 2011. PG&E will share the results of that comprehensive study with the CPUC.

BACKGROUND: Types and Uses of Automated Valves

There are two types of automated valves:

- Automated Remotely Controlled Valves (RCVs) allow a mainline valve to be opened and closed by a remote operator located at a gas control center.

- Automatic Line Rupture Shut-off Valves (ASVs) automatically close when they detect a line rupture (*e.g.* falling pressure, increasing flow rate) or any other condition that they are programmed to detect. These valves close without human intervention.

If a gas line is ruptured or there is another type of unplanned gas release, automated valves of either type can close the affected line much more quickly than a manually operated valve, isolating the ruptured section and reducing the volume of gas vented at the pipeline break. Automated valves do not prevent ruptures. Studies by pipeline experts indicate that most of the harm to persons and property following a natural gas pipeline rupture typically occurs within a few seconds or minutes of the initial rupture and energy release, before even an automated valve of either type can respond.

ASSESSMENT METHODOLOGY

PG&E considered a number of screening criteria to identify preliminary candidates for valve replacements, including:

- *Pipeline location.* PG&E's preliminary analysis focused on pipeline segments located within high consequence areas (HCAs) and took account of other environmental factors such as proximity to an earthquake fault, landslide areas, or major waterways.
- *Pipeline characteristics.* PG&E focused on a number of pipeline characteristics, including materials, age, diameter, operating pressure, and wall thickness.

PRELIMINARY ASSESSMENT RESULTS

Based on these screening criteria, PG&E identified approximately 565 miles of HCA pipeline for further evaluation. Within these 565 miles, PG&E estimates there are approximately 300 candidate valves for automation. PG&E is about one-third of the way through its evaluation of these candidate valves. Maps showing the general location of the valves in this first phase of evaluation are included as Appendix A.[3] A list of those general valve locations is included as Appendix B.[4] PG&E will continue to assess the remaining two-thirds of the candidate valves with the assistance of a third-party firm and provide a more detailed plan with the Commission as part of its Pipeline 2020 program.

RANGE OF POTENTIAL COSTS

The cost of valve replacements or retrofits is location-specific and varies significantly. Where the valve is easily accessible and requires only a retrofit, the cost could be as low as $100,000. In areas that are more difficult to access and require a valve replacement,

[3] A number of the candidate valves are located on the three parallel pipelines in the San Francisco Peninsula. These three pipelines provide gas to over 18% of PG&E's gas accounts. They are connected together (cross-tied) at various points along their route, beginning at Milpitas Terminal and ending in San Francisco. The potential valve replacement candidates shown in Appendix A include valves on both these mainline and crossties.

[4] PG&E will share more detailed valve location information with the Commission and local first responders.

the cost could be as high as $1,500,000.[5] Other factors affecting cost will be considered and addressed in our refined analysis. These factors include:

- The availability of a Supervisory Control and Data Acquisition (SCADA) communication points at the site;
- The availability of telecommunications and electric power facilities at the site;
- The scope of protocols, training and system upgrades and enhancements to ensure effective operation of the automated valve technology; and
- The complexity of isolating and taking portions of the system out-of-service to perform the installation work.

PG&E's estimates primarily reflect capital costs. Operation and maintenance costs, and costs for improving System Gas Control to provide increased oversight for remote control points have not been included in the cost estimates provided in this preliminary report, but will be included in the results of the comprehensive study.

NEXT STEPS

As part of the Pipeline 2020 program, PG&E has engaged a third-party firm to review and refine the preliminary analysis. The detailed study scope is included in Appendix C.

[5] Based on PG&E's past experience, the estimated average cost of installing a valve with automatic or remote controls at an existing manual valve for a large diameter (20" and larger) pipe is approximately $750,000.

APPENDIX A
Location of Potential Valve Replacement Candidates – Initial Evaluation

Redacted

APPENDIX A, continued
Location of Potential Valve Replacement Candidates – Initial Evaluation

Redacted

APPENDIX B
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
East Bay	L191	Antioch
East Bay	L191	Antioch
East Bay	SP-5	Antioch
East Bay	SP-5	Antioch
East Bay	SP-5	Antioch
East Bay	SP-5	Antioch
Bay Area Loop	L114	Brentwood, Unincorporated
Bay Area Loop	L114	Brentwood, Unincorporated
Bay Area Loop	L114	Brentwood, Unincorporated
Bay Area Loop	L303	Brentwood, Unincorporated
Bay Area Loop	L303	Brentwood, Unincorporated
Peninsula	L109	Hillsborough
Peninsula	L132	Hillsborough
Peninsula	L132	Hillsborough
Peninsula	L132	Hillsborough
East Bay	SP-3	Concord
East Bay	SP-3	Concord
East Bay	SP-3	Concord
Peninsula	L132B	Daly City
Sac Valley	L108	Elk Grove
Bay Area Loop	L107	Fremont
EastBay	L153	Fremont
Bay Area Loop	L303	Fremont
Bay Area Loop	L107	Fremont
Bay Area Loop	L131	Fremont

APPENDIX B, continued
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
Bay Area Loop	L131	Livermore
Bay Area Loop	L131	Livermore
Bay Area Loop	L131	Livermore
Bay Area Loop	L114	Livermore
Bay Area Loop	L303	Livermore
Bay Area Loop	L131	Alameda County
Bay Area Loop	L114	Livermore
Bay Area Loop	L303	Livermore
Peninsula	L109	Menlo Park
Peninsula	L132	Menlo Park
San Jose	L100	Milpitas
Peninsula	L101	Milpitas
Peninsula	L109	Milpitas
Peninsula	L132	Milpitas
Backbone	L300A	Milpitas
Backbone	L300B	Milpitas
Backbone	L300A	Morgan Hill
Backbone	L300A	Morgan Hill
Backbone	L300B	Morgan Hill
Backbone	L300B	Morgan Hill
Peninsula	L101	Mountain View
Peninsula	L101	Mountain View
Peninsula	L101	Mountain View
Peninsula	L109	Mountain View
Peninsula	L109	Mountain View

APPENDIX B, continued
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
Peninsula	L109	Mountain View
Peninsula	L132	Mountain View
Peninsula	L132	Mountain View
Peninsula	L132	Mountain View
Peninsula	L132A	Mountain View
EastBay	L153	Newark
Bay Area Loop	L303	Oakley
EastBay	L191	Pittsburg
EastBay	SP-3	Pittsburg
EastBay	SP-3	Pittsburg
EastBay	SP-3	Pittsburg
EastBay	SP-3	Pittsburg
Peninsula	L109	Redwood City
Peninsula	L132	Redwood City
Peninsula	L132	Redwood City
Peninsula	L132	Redwood City
Peninsula	L132	Redwood City
Peninsula	L147	Redwood City
North Bay	L210A	Solano County
North Bay	L210A	Solano County
North Bay	L210A	Solano County
Sac Valley	L123	Roseville
Sac Valley	L108	Sacramento
Sac Valley	L108	Sacramento
Sac Valley	L108	Sacramento

APPENDIX B, continued
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
Sac Valley	L108	Sacramento
Peninsula	L132	San Bruno
Peninsula	L109	San Bruno
Peninsula	L132	San Bruno
Peninsula	L132	San Bruno
Peninsula	L101	San Carlos
Peninsula	L101	San Carlos
Peninsula	L101	San Carlos
San Jose	L100	San Jose
Backbone	L300A	San Jose
Backbone	L300B	San Jose
Backbone	L300B	San Jose
Backbone	L300B	San Jose
San Jose	L100 / 0821-01	San Jose
East Bay	L153	San Leandro
East Bay	L153	San Leandro
North Bay	L210A	Suisun City
North Bay	L210A	Suisun City
North Bay	L210A	Suisun City
East Bay	L153	Union City
East Bay	L153	Union City

APPENDIX C
Scope of Study

PG&E will engage one or more third-party firms to conduct a comprehensive analysis of valve automation across PG&E's natural gas transmission system. This third-party analysis will include the following items, as well as review of (and refinements to) PG&E's preliminary assessment. This third-party analysis will deepen both PG&E's and the industry's understanding of whether and where ASV/RCV equipment should be used. Among other things, the third-party analysis will:

1. Research the industry's use of ASV/RCV equipment on gas transmission systems and identify best practices for design and operation, including the alternatives and merits of available ASV/RCV technology.
2. Survey major gas pipeline operators to collect information on the reasons operators use this equipment, their operating experience, the technology they employ, and the advantages and disadvantages the operators perceive to exist for the use of this technology in general, as well as the specific technology employed by the operator.
3. Evaluate distinctions in how ASV/RCV equipment is employed between FERC regulated pipeline systems, intrastate systems, gas utilities (transmission and distribution) and international pipeline systems.
4. Review PG&E's deployment of ASV/RCV equipment and manual isolation valves and the development of alternative deployment levels, and assess the pros and cons of various levels of additional deployment.

The following specific assessments will be performed:

- Evaluate and improve the pipeline segment selection criteria described above, developed as part of the preliminary assessment.
- Examine the reliability of ASV/RCV technology and the associated required maintenance activities and costs.
- Examine industry and federal government analyses of the merits of ASV/RCV equipment, including a review of state code changes which may have been adopted subsequent to the Texas Eastern Transmission Corporation (TETCO) pipeline explosion in New Jersey in 1994.

PG&E will also work with the third-party firm(s) on the following implementation issues related to ASV/RCV installations:

- Examine the impact of ASV/RCV expansion on PG&E's SCADA system.
  a) System capacity to provide data and control communications.
  b) Challenges related to installing SCADA at a host of remote sites.
  c) Required enhancements to Gas System Operations protocols and training.

APPENDIX C, continued
Scope of Study

- Examine the extent to which remote control will impact operating decisions, the protocols and risk assessment required to make those decisions, and the level of field verification required.
- Examine the feasibility of adding ASV/RCV to valves in a relatively short time period (*e.g.,* permit requirements or land rights for significant station modification or creation of new stations could require significant lead times).
- Examine the construction feasibility to determine obstacles that are particularly costly and time-consuming to resolve (*e.g.* valves could require replacement and/or relocation because they cannot be automated in their current location).
- Examine the extent to which the addition of automation equipment above ground poses a heightened security risk because the equipment is more visible or accessible to persons other than trained and authorized personnel.
- Assess the need for additional physical resources to replace, retrofit or install ASV or RCV valves.

PG&E has reviewed preliminarily the industry literature related to pipeline isolation and the use of ASV/RCV technology. These studies were used to conduct the preliminary assessment and develop this report. A third-party firm will undertake a more thorough review of this documentation and also investigate additional industry literature available on this subject.

1. Eiber, R.J. and McGehee, W.B., *Design Rationale for Valve Spacing, Structure Count, and Corridor Width*, PR249-9631, PRC International, May 30, 1997.
2. Shires, T.M. and Harrison, M.R., *Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implication for Today's Natural Gas Pipeline System*, GRI-98/0367.1, December 1998.
3. Sparks, C.R. et al., *Remote and Automatic Main Line Valve Technology Assessment, Appendix, B*, GRI-95/0101, July 1995.
4. Sparks, C.R., Morrow, T.B. and Harrell, J.P., *Cost Benefit Study of Remote Controlled Main Line Valves*, GRI-98/0076, May 1998.
5. Texas Eastern Transmission Corp., *Natural Gas Pipeline Explosion and Fire*, NTSB/PAR-95/01.
6. Process Performance Improvement Consultants, (P-PIC), White Paper on Equivalent Safety for Alternative Valve Spacing, Draft April 18, 2005.
7. U.S. Department Of Transportation, Research and Special Programs Administration, Remotely Controlled Valves on Interstate Natural Gas Pipelines (Feasibility *Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996)*, September 1999.
8. Gas Research Institute 00/0189 "A Model for Sizing HCA's Associated with Natural Gas Pipelines", December 2001.

APPENDIX C, continued
Scope of Study

9. Eiber, R.J. and Kiefner and Associates, *Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing (To ASME Standards Technology, LLC)*, July 2010.

ATTACHMENT 3

ACCELERATED GAS SYSTEM SURVEY INITIAL REPORT

In a letter from Paul Clanon to PG&E dated September 13, 2010 (Item 3) and in Ordering Paragraph 12 of Resolution L-403, the Commission directed PG&E to conduct an accelerated system survey of all natural gas transmission pipelines, giving priority to segments in Class 3 and Class 4 locations.

PG&E responded on September 20, 2010 and September 23, 2010, by committing to 1) complete an aerial accelerated system survey of its entire gas transmission system using laser detection technology; 2) complete a field evaluation wherever there are indications of possible leaks identified by aerial instruments; and 3) make repairs as necessary whenever leaks are found. PG&E also committed to complete accelerated system surveys using traditional methods for all Class 3 locations, Class 4 locations, and High Consequence Areas (HCAs) on its system. This initial report summarizes the results of these surveys.

As noted in our September 20, 2010 and September 23, 2010 letters, accelerated system surveys using traditional methods for Class 1 and Class 2 pipelines will be completed by December 15, 2010.

PG&E conducted an aerial survey of gas transmission lines and distribution feeder mains operating above 60 psig[6] using laser methane detection technology. This aerial survey provided a rapid safety survey of the entire transmission system. In the few areas where the aerial surveys were not possible, such as near wind turbine farms, PG&E performed an accelerated ground system survey. In addition to the aerial survey, PG&E also performed a traditional accelerated ground system survey of approximately 2,500 miles of Class 3 and Class 4 pipeline operating above 60 psig, and HCA transmission mains in Class 1 and Class 2 locations.[7]

Although the entire accelerated survey will not be completed until December 15, 2010, this initial report provides the Commission with the number of leaks identified during the

[6] PG&E has approximately 6,700 miles of gas pipe operating above 60 psig, all of which were covered by the aerial survey, except for the Peninsula lines, which were foot surveyed immediately after the accident. Approximately 5,700 miles of this pipe are considered a "transmission line" or a "transmission main" under U.S. Department of Transportation regulations. In addition, PG&E is the majority owner and operator for Standard Pacific Gas Line, Inc. (StanPac), which owns approximately 54 miles of natural gas transmission pipelines in California. The miles reported in this letter include an accelerated system survey of StanPac's transmission system.

[7] PG&E has not yet been able to complete approximately 2.3 miles of its accelerated ground system survey. These 2.3 miles include areas where PG&E needs permission to access active military installations or where it needs to survey certain portions of the transmission pipeline under waterways.

first phase of the accelerated survey that required immediate repair (i.e., Grade 1 leaks).[8] As we have repeatedly stated, any issue, and certainly any gas leak, identified as a potential threat to public safety is always addressed right away. We do not delay or defer work that is necessary for public safety. In particular, any leak indication that is potentially hazardous is considered a Grade 1, and the employee or contractor who finds the leak remains at the location of the leak to ensure public safety until a crew arrives to take corrective action.

The aerial survey and the accelerated ground system survey in Class 3, Class 4 and HCA locations identified four (4) Grade 1 leaks on natural gas transmission mains, all in Class 3 HCA locations, which required immediate repair. These leak repairs would normally be reported in our Annual Report for calendar year 2010, Form PHMSA F 7100.2-1 due March 15, 2011, and our semi-annual reporting on our Integrity Management Program due February 28, 2011.

The details on these four Grade 1 leak repairs are as follows:

1. On September 19, 2010, a leak was found on a valve on Line 300B in the Redacted. The leak was repaired by tightening the cap/bolt.

2. On September 28, 2010, a below ground leak was found on Line 50 near Highway 99 in Gridley. The leak was repaired by replacing a section of pipe.

3. On October 4, 2010, an above ground leak was found on a flange on Line 210A at Redacted which is an enclosed facility. All bolts were tightened, which stopped the leakage.

4. On October 7, 2010, a leak was found on an underground valve on Line 0405-01 in Napa. The leak was repaired by greasing the valve.

In addition, PG&E also identified and immediately repaired 34 other Grade 1 leaks on distribution lines, distribution feeder mains operating above 60 psig, or other facilities appurtenant to transmission mains. All of those leaks have been repaired. Table 1, below, provides a listing of these other leaks, showing the location and corrective action.

As noted in our September 20, 2010 and September 23, 2010 letters, PG&E will complete the accelerated system survey of approximately 4,000 miles of Class 1 and Class 2 transmission pipelines by December 15, 2010. Any Grade 1 leaks identified in Class 1 or Class 2 locations will be repaired immediately. In addition, and as PG&E wrote in its September 23, 2010 letter, it will analyze all leak information gathered through both the accelerated aerial and ground system surveys to identify any trends and will review any recommendations with the Commission by January 31, 2011.

---

[8] Consistent with industry standards, all indications of potential leaks receive a grade. Grade 1 leaks are repaired immediately. Indications of potential leaks that do not require immediate repair are assessed and scheduled for any necessary corrective action.

TABLE 1
Ground and Aerial Accelerated System Survey
All Grade 1 Leak Repairs

City	Facility	Corrective Action
American Canyon	Flange	Tighten
Berkeley	Valve	Tighten
Chico	Service Tee	Tighten
Cupertino	Valve	Greased valve
Dublin	Regulator	Tighten
Firebaugh	Valve - Meter Station	Greased valve
Firebaugh	Valve - Meter Station	Greased valve
Fremont	Distribution	Welded Patch
Graton	Distribution	Installed Clamp over leak
Gridley	Main	Replaced pipe
Hilmar	Regulator	Replaced Regulator
Hollister	Valve	Tighten
Ione	Valve	Greased valve
Millbrae	Fitting on Main	Tighten
Modesto	Regulator	Replaced Regulator
Modesto	Regulator	Adjusted relief setting
Modesto	Regulator	Replaced Regulator
Morgan Hill	Main	Installed Sleeve over leak
Morgan Hill	Valve	Tighten
Napa	Valve	Greased valve
Oakland	Valve	Greased valve
Oakland	Valve & Regulator	Greased valve
Oakland	Distribution	Replaced Cap and Plug
Oakland	Regulator	Tighten
Oakland	Regulator	Replaced Regulator
Oakland	Valve	Greased valve
Oakland	Service Tee	Tighten
Oakland	Valve	Tighten
Palo Alto	Valve	Tighten
Patterson	Regulator	Tighten
Riverbank	Service Tee	Replaced cap
Rocklin	Distribution	Installed Electrofusion over Cap
Sacramento	Service Tee	Tighten
Sacramento	Service Tee	Tighten
Sacramento	Fitting on Main	Tighten
San Jose	Service Tee	Tighten
Stockton	Valve	Tighten
Stockton	Service Tee	Tighten

ATTACHMENT 4

CURTAILMENT PLANS

The letter from Paul Clanon to PG&E dated October 15, 2010 (Items 1, 2, and 3) directed PG&E to provide: (1) information on a gas curtailment plan in the event of the need to curtail gas deliveries in the San Francisco and Peninsula areas; (2) an electricity contingency plan in the event gas service is curtailed to the Potrero Power Plant; and (3) results of the detailed analysis PG&E was performing concerning the effects of the reduction of operating pressure and the possible strategies to reduce or avoid customer curtailments this winter.

BACKGROUND

PG&E uses two Commission-approved design criteria to set the capacity of its gas system, an Abnormal Peak Day (APD) and a Cold Winter Day (CWD). An APD occurs on average 1 in 90 years, and is designed to ensure continued service to all residential and small-commercial customers (core customers) while curtailing service to large-commercial and industrial customers (noncore customers). Curtailment is necessary to protect service to residential and small-commercial (core) customers and to maintain safe system operating pressures. In return for the risk of curtailment, noncore customers receive a discounted transmission rate. A CWD occurs on average 1 in 2 years, and is designed to ensure that no customers—core or noncore—are curtailed.

Depending on the mix of customers fed from a particular gas system, the system capacity is designed using either APD or CWD. APD and CWD represent minimum criteria; many portions of PG&E's gas system exceed these criteria and deliver greater reliability to customers.

GAS CURTAILMENT PLAN

Each year before the winter cold season, PG&E sends notices to its noncore customers reminding them of the potential for gas curtailments, their obligations under their tariff, and how they will be notified in the event curtailments are needed. Because of system changes caused by the Line 132 rupture, PG&E has developed a specific outreach program this year for customers in San Francisco and on the Peninsula and is undertaking several mitigation measures to reduce curtailments.

PG&E's outreach program is now underway for the 109 noncore gas customers on the San Francisco Peninsula and is aimed at ensuring they are fully prepared for any potential curtailments. Important elements of the communication plan are:

- All noncore customers have an assigned account manager.
- Beginning on October 14, 2010, PG&E initiated phone or face-to-face contacts with noncore customers in San Francisco and on the Peninsula to: 1) explain the potential for curtailments; 2) help those customers start planning how they would modify their operations if a curtailment is called; and 3), ensure that customers with alternative fuel capability have sufficient fuel on hand.

- Week of October 18, 2010 – PG&E began follow-up contacts with customers to support development of their plans for managing a curtailment.
- Late November 2010 – PG&E will provide formal notice of the potential for curtailment and levels of curtailment to all noncore customers on the San Francisco Peninsula. The allowed usage level will be based on the necessary percentage load reduction needed in each specific area to meet core gas customer reliability obligations under different weather scenarios. Also, customers will be able to receive automated cold weather messages from PG&E.

If curtailments are required, account managers will e-mail and fax (when a fax number is available) curtailment notifications in advance and make follow-up phone calls to customers who are to be curtailed. Curtailments will be from midnight to midnight.

Finally, there is a charge of $50 per decatherm, plus the Daily Citygate Index Price[9] if customers are not in compliance with required curtailments. PG&E relies primarily on the noncompliance charge to ensure compliance with curtailment orders. PG&E remotely monitors most noncore customer usage and will shut off a customer if that customer's noncompliance jeopardizes public safety or service to core customers.

ELECTRICITY CONTINGENCY PLAN

The Mirant Potrero Power Plant's Unit 3 is a natural gas-fired steam unit and represents 57% of the noncore load in San Francisco.[10] In the event PG&E curtails natural gas service to Potrero Power Plant Unit 3, the remaining electric transmission system along with the Potrero combustion turbines are adequate to meet winter peak electric demand in San Francisco without any need for electric service curtailment.

Currently, there are two electric transmission projects under construction: PG&E's recabling project, which is in its final construction phase and the Trans Bay Cable Project, which is in its final testing phase. Once fully operational, those projects would further increase system capability. In a letter dated January 12, 2010, the CAISO announced that Potrero Unit 3 can be retired "once the Trans Bay Cable Project demonstrated its reliability."

PG&E understands the Trans Bay Cable Project is undergoing its final testing this month. In fact, the CAISO has not been dispatching Potrero Unit 3 in October 2010 while the Trans Bay Cable is in its final testing mode.

PG&E's recabling project is in its final stage of construction. The first of the two cables was completed and has operated reliably since June 2010. The second cable is almost complete and is scheduled for operation by the end of November/beginning of December 2010.

---

[9] The DCI is the PG&E Daily Citygate Index Price as published in Gas Daily, rounded up to the next whole dollar. If the price is not published on a given day, the previous price will apply.

[10] The other three operating units at Potrero Power Plant are diesel-fueled combustion turbine peaking units and would not be affected by a gas curtailment.

Although highly unlikely, an electricity curtailment is theoretically possible if (a) gas service is curtailed to the Potrero Unit 3, (b) both Trans Bay Cable and PG&E's recabling projects are not complete and not operating, and (c) more than one other electric transmission facility located in San Francisco became unavailable. PG&E has begun discussions with the CAISO to develop a plan for this unlikely event.

EFFECTS OF THE REDUCTION OF OPERATING PRESSURE AND POSSIBLE STRATEGIES TO REDUCE OR AVOID CUSTOMER CURTAILMENTS THIS WINTER

Strategy to Increase System Capacity and Reduce Curtailments

PG&E is implementing the following strategies and steps to increase the Peninsula local transmission system capacity to reduce the potential for customer curtailments:

- Making modifications to Milpitas Terminal to allow for safe, independent pressure set points on L-101, L-109, and L-132.
- Installing a new cross-tie and regulation between L-109 and L-132 upstream of the section of L-132 that is out of service (San Andreas cross-tie).
- Installing regulation at the existing Healy Station cross-tie between L-109 and L-132 just downstream of the section of L-132 that is out of service.
- Installing regulation at the existing Sierra Vista cross-tie to allow L-101 to support L-132.
- If needed during cold weather, manually operating the Edgewood cross-tie to allow L-101 to support L-132.
- Closing a main line valve on L-132 to reduce the demand and flow on L-132 and utilize the higher capacity of L-101 instead.
- Manually operating some distribution regulator stations during cold weather to ensure full supply pressure to distribution systems, thereby maximizing service reliability.

In addition, because the Potrero Power Plant's Unit 3 is 57% of the noncore load in San Francisco and Unit 3 can be curtailed without impacting electricity supply, PG&E has begun working with both the CAISO and Mirant to explore the potential to voluntarily curtail Unit 3 prior to other noncore customers. This would significantly reduce the likelihood of other noncore curtailments.

Results of Curtailment Analysis

PG&E has analyzed system capacity for Lines 101, 109, and 132 operating at various independent pressures on each of the three lines. PG&E has estimated noncore curtailment levels that would be needed to eliminate or reduce curtailments to core customers, consistent with our design criteria. These estimated curtailment levels assume completion of the system improvement strategy described above, and are estimates only; final curtailment plans will be developed once a determination of allowable operating pressures is complete. As mentioned above, PG&E's current approved design criteria consist of the Abnormal Peak Day (APD), in which all core customers are served and noncore customers are curtailed, and the Cold Winter Day (CWD), in which all customers are served—core and noncore. These represent minimum criteria; many portions of PG&E's gas system exceed these criteria and deliver greater reliability to noncore customers.

Estimated curtailments are provided below for three daily average temperatures in San Francisco:

- CWD, which occurs at 42 degrees Fahrenheit (F) daily average[11] temperature.
- Midpoint between CWD and APD, which is 37 degrees F daily average temperature.
- APD, which occurs at 32 degrees F daily average temperature.

System Capacity at 300 psig:

Lines 101, 109, and 132 currently are all operating at 300 psig. At these operating pressures, PG&E cannot meet either its CWD or APD design criteria. Noncore curtailments will be needed at temperatures warmer than a CWD. On an APD, 100% of all San Francisco and Peninsula noncore customers will need to be curtailed and some large core customers in the San Francisco area will need to be curtailed. At the midpoint temperature of 37 degrees daily average temperature, 100% of the noncore customers in the approximate area of San Francisco and South San Francisco will need to be curtailed.

These curtailment levels can be reduced if Line 101 and/or Line 109 are operated above 300 psig.

System Capacity at Pressures Above 300 psig:

PG&E analyzed curtailments at pressures in these lines of 337 psig and 375 psig, representing a 10% and 0% reduction from the pre-event pressure of 375 psig. At these increased pressures, noncore customers can be fully served under a CWD. At 37 degrees F daily average temperature, noncore curtailments could range from approximately 25% to 75% of San Francisco noncore demand, with lower curtailments at higher operating pressures. On an APD, noncore curtailments range from San Francisco south to other parts of the Peninsula. To avoid curtailment of core customers, L-101 and L-109 must both operate at pressures above 300 psig or L-101 must operate at a pressure at or near 375 psig.[12]

PG&E will develop a final curtailment plan when operating pressures are finalized and system capacity for winter is known.

---

[11] These temperature criteria are based on daily average temperature, not the lowest temperature reached during the day.

[12] For example, curtailment of some core customers occurs on an APD if L-101 is operated at 337 psig while L-109 and L-132 remain at 300 psig, in addition to curtailment of 100% of noncore demand along the entire Peninsula.