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	R.11-02-019 (Filed February 24, 2011)

VERIFIED STATEMENT OF PACIFIC GAS AND ELECTRIC COMPANY'S VICE PRESIDENT OF GAS TRANSMISSION MAINTENANCE AND CONSTRUCTION IN RESPONSE TO RULING OF ASSIGNED COMMISSIONER AND ASSIGNED ADMINISTRATIVE LAW JUDGE

JOSEPH M. MALKIN
Orrick, Herrington & Sutcliffe LLP
The Orrick Building
405 Howard Street
San Francisco, CA 94105
Telephone: (415) 773-5505
Facsimile: (415) 773-5759
E-Mail: jmalkin@orrick.com

ALEJANDRO T. VALLEJO
Pacific Gas and Electric Company
Law Department
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-1611
Facsimile: (415) 973-5520
E-Mail: AXVU@pge.com

I, M. KIRK JOHNSON, do declare:

1. I am the Vice President, Gas Transmission Maintenance & Construction for Pacific Gas and Electric Company (PG&E).

2. I received a B.S. in mechanical engineering from the University of California, Davis, in 1980. I have been employed by PG&E as an engineer since graduating, spending approximately 30 years in gas operations.

3. I am providing this verified statement in compliance with the August 19, 2013 ruling of Assigned Commissioner Florio and Assigned Administrative Law Judge Bushey. Much of the information is based on my understanding and belief regarding the subject matters discussed, rather than firsthand knowledge of each and every fact.

Overview

4. On July 3, 2013, PG&E submitted for filing a document entitled "Errata to Pacific Gas and Electric Company's Supporting Information for Lifting Operating Pressure Restrictions on Lines 101 and 147," formally advising the Commission and parties that we had identified errors in some of the information filed with the Commission in support of our October 31, 2011 request to lift operating pressure restrictions on Lines 101, 132A and 147. That document identified two types of errors in our previously-filed information:

(a) Errors based on inaccurate pipe specifications. We have identified errors in our previously-submitted pipe specifications for a total of four segments of Line 147. Three of these lowered the maximum allowable operating pressure (MAOP) of Line 147 below the Commission-authorized 365 pounds per square inch gauge (psig); the other had no impact.

(b) Errors based on a corrected regulatory interpretation. We have recently concluded based on a conservative reading of the federal pipeline regulations that we inappropriately relied on a 1989 hydro test to establish the MAOP for one segment of Line 101.

5. As a result of these findings, we reduced the MAOP of Lines 101 and 147 to 330 psig. Although we have acknowledged the need to correct our previously-submitted documentation for Line 147, all of the Class 3 and 4 and Class 1 and 2 high consequence area pipe had been strength tested to pressures well in excess of the 365 psig pressure we asked the Commission to authorize. Strength testing is the industry's most trusted and reliable safety validation. And our new strength testing protocols go beyond the already stringent federal guidelines, adding a "spike test" to in situ pipe whenever feasible.

6. The Commission's Safety and Enforcement Division (SED) has emphasized the importance of strength testing to guard against any recordkeeping shortcomings. SED has agreed that our operational actions with regard to Lines 147 and 101 have addressed all public safety issues.[1]

7. Since the tragic San Bruno accident through the end of 2012, we strength tested approximately 340 miles – an unprecedented amount in such a short period of time. We also replaced 40 miles of pipe, installed 59 automated valves, retrofitted 78 miles of pipe for in-line inspection and improved our leak response time from fourth quartile to first quartile among pipeline operators across the nation. In 2013, we expect to strength test or verify records for an additional 204 miles, replace an additional 64 miles of pipe, automate an additional 75 valves, and perform in-line inspections of 78 miles of pipeline.

8. As an interim safety measure, we undertook an unprecedented effort to collect and organize our records to validate the MAOP of our entire gas transmission system. We have digitally converted more than 3.8 million paper records which are now available through a centralized electronic document management system. That effort required processing approximately: 16,000 Pipeline Features Lists (PFL), 500,000 MAOP components and more than 40 million data fields including more than 3 million MAOP specifications.

9. Still, we recognize that our older, historic records are not complete. That is why we are embarked on a program, supported by the Commission in Decision 11-06-017, to strength test to modern standards or replace all transmission pipe for which we do not have complete, verifiable records of an appropriate strength test.

10. As described in detail below, in October 2012 we discovered a human error in the MAOP validation records for one segment of Line 147. This discovery prompted us to re-analyze the MAOP records for the rest of Line 147. Through this review, we identified three segments that were erroneously characterized based on documents that did not accurately reflect the pipe characteristics.

11. The MAOP validation records for Line 147 were among the earliest we developed. The issues we identified in our Line 147 documentation revealed gaps in the early stages of our MAOP validation process. As described below and as will be more fully discussed by our experts at the September 6, 2013 hearing, we have continued to refine and improve this process over the year and a half since we filed our pressure restoration request for Lines 101 and Line 147. Examples of such enhancements include: (a) additional independent third-party review; (b) testing and validation of conservative engineering assumptions; and (c) implementing a computerized engineering data validation tool.

12. These measures are part of our continuous improvement efforts, and raise our level of confidence in the rigor of our process. We will also continue to strength test our transmission pipe so that the safety of all of our pipelines will ultimately be confirmed by a strength test.

13. The inaccuracies in our Line 147 documentation also prompted us to review the appropriate MAOP for all of Lines 101, 132A and 147. This review included revisiting the way we were interpreting the federal code provisions related to class locations (i.e., the population density of areas in which pipelines operate). Specifically, we came to focus on a section of the federal code that was repealed over 15 years ago. This provision, which was enacted as part of the original Pipeline Safety Act of 1970, gave pipeline operators a three-year window from 1971

to 1974 to determine the class locations in which their pipelines were operating and validate their respective MAOPs via strength tests if necessary. We concluded that the code provision prevented us from relying on post-1974 strength tests (tests that occurred outside the window) to validate the MAOP of pipelines that experienced pre-1971 population density growth affecting their class locations.

14. As explained below, our corrected interpretation resulted in decreasing the MAOP of Line 101 from 365 pounds per square inch gauge (psig) to 330 psig. This decrease is not due to any safety or engineering concerns, but rather from an effort to ensure strict code compliance. (*See* paragraphs 54 to 64 below.)

Background

15. In the immediate aftermath of the September 9, 2010 San Bruno accident, Commission Executive Director Paul Clanon directed PG&E to reduce the operating pressure on Line 132 to 20 percent below the operating pressure at the time of the accident. We had already reduced the pressure on Line 132 and our other Peninsula transmission lines by 10 percent. In response to the Executive Director's directive, we reduced the operating pressure on Line 132 and the other Peninsula transmission lines by another 10 percent. These reductions included Lines 101, 132A and 147, whose operating pressure was reduced from 375 psig to 300 psig.

16. Line 101 is a local transmission line that runs from Milpitas Terminal in Santa Clara County to PG&E's San Francisco Gas Load Center. Line 132A is a 1.5-mile cross-tie in the Mountain View area that connects Line 101 to Lines 109 and 132, the two other local transmission lines running up the Peninsula. Line 147 is a 3.8-mile cross-tie that connects Line 101 to Lines 109 and 132 at Edgewood Road Crossover.

17. In D.11-09-006, the Commission adopted a procedure for lifting operating pressure restrictions on pipelines where the Commission had directed PG&E to lower pressure.

18. Even though the pressure reduction on Lines 101, 132A and 147 had been voluntary, we agreed with Commission staff that it was in the public interest to subject those lines to a similar public process in deciding whether to authorize lifting the pressure restriction.

19. Starting on October 31, 2011, we submitted to the Commission the Supporting Information called for by Ordering Paragraph 4 of D.11-09-006 to lift the operating pressure restriction on Lines 101, 132A and 147.

20. As the PG&E officer responsible for gas transmission system engineering, on November 15, 2011, I provided a declaration in support of PG&E's request for the restoration of operating pressure on Lines 101, 132A and 147. In that declaration, I certified that:

a. PG&E engineers had validated the engineering and construction through records review of piping and all associated components, including off-takes, as documented in the submitted exhibits;

b. PG&E had successfully completed strength testing of all transmission pipe segments and components on Lines 101, 132A and 147 operating at or above 20 percent of specified minimum yield strength (SMYS) for which we did not have records of a prior strength test in accordance with the applicable standards at the time they were performed, in accord with Title 49 of the Code of Federal Regulations, Part 192, Subpart J, at pressures above those required to confirm the safe operation of Lines 101, 132A and 147 at a maximum operating pressure 365 psig with an additional margin of safety;

c. The work followed PG&E's procedures; and

d. In my professional judgment, as the gas engineering officer of PG&E, Lines 101, 132A and 147 were and are safe to operate at 365 psig.

21. D.11-12-048, *Decision Establishing Maximum Operating Pressure for Lines 101, 132A, and 147*, authorized PG&E to operate Lines 101, 132A, 147, and associated shorts, with a maximum operating pressure of 365 psig.

Line 147

22. Our strength tests conducted on Line 147 were all with minimum test pressures above 600 psig, which supports an MAOP of above 400 psig in a Class 3 location.

SB_GT&S_0008230

23. After issuance of D.11-12-048, we increased the operating pressure on Lines 101, 132A and 147 as necessary to meet winter load, but kept the operating pressure on all three lines below the MAOP of 365 psig. The highest actual operating pressure experienced by Line 147 after the issuance of D.11-12-048 was 355.4 psig on May 19, 2012.

24. On May 24, 2012, we reduced the operating pressure of the Peninsula transmission system, including Lines 101, 132A and 147, to below 300 psig. We did this because we were starting numerous upgrade projects on the Peninsula system (Lines 101, 109, 132, 132A, and 147), and lowering the pressure simplified the clearance procedures and operations during the tie-in of these projects while also reducing the risk of inadvertent over-pressurization. We were able to do this at that time because of the lower load of the off-peak season. In December of 2012, we increased the operating pressure of Line 101 to meet winter load.

<u>Line 147, Segment 109 (Human Error)</u>

25. On October 15, 2012, a routine PG&E leak survey of Line 147 discovered a gas leak at mile-point 2.29 near the intersection of Rogers Avenue and Brittan Avenue in San Carlos, on what is known as Segment 109. The leak surveyor[2] obtained a reading of one percent gas and initially graded the leak as a Grade 1. That grade is for a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until conditions are no longer hazardous. A reading of one percent gas does not meet PG&E standards for designating a leak as hazardous, i.e., Grade 1, unless it is in, at or under a building, or in the opinion of the leak surveyor poses an immediate hazard. The grading reason code on the A Form, required for leaks designated as Grades 1, 2+ or 2 with less than two percent gas, is "T", indicating that the leak was graded 1 because it was on a Transmission or Regulation facility.

26. A gas construction crew promptly responded to the leak. The crew drilled holes over the transmission line and used a leak detection device to sample each hole. Within three hours of the original leak report, the construction crew re-graded the leak as a 2+, which is defined as a leak that is non-hazardous to persons or property at the time of detection, but still requires a scheduled priority repair within 90 days or less. Our standards specify that it is appropriate to re-grade a leak from a Grade 1 to a Grade 2+ if it meets the criteria for Grade 2+.

27. On October 18, 2012, our crew exposed the pipe in the area of the leak on Line 147. Our pipeline engineer on site visually investigated and realized that the long-seam weld of the exposed section of pipe appeared to be of the early vintage A.O. Smith variety.

28. Our pipeline engineer recognized a discrepancy between the actual field conditions (appeared to be A.O. Smith) and the PG&E documented specifications that he had reviewed prior to his arrival at the scene of the leak investigation indicating that the pipe was Double Submerged Arc Weld (DSAW). He took photographs of the pipe, which he then sent to colleagues at PG&E to confirm his identification of the seam type and for guidance on appropriate actions for repair.

29. The pipeline engineer was aware that Line 147 was operating below 300 psig. To determine whether a further reduction in pressure or other immediate action was required to protect public safety, that day the pipeline engineer calculated the most conservative operating stress of the pipeline utilizing PG&E assumed values for the specified minimum yield strength (SMYS) and joint efficiency factor of A.O. Smith long-seam pipe (33,000 psi and 0.8, respectively). The calculation showed that the current operating pressure was well below 50% of SMYS and that it was safe to continue to operate at that pressure.

30. On October 24, a pipeline corrosion engineer confirmed that the photographs indicated that this was A.O. Smith pipe.

31. Over the next several weeks the pipeline engineer performed extensive review of the applicable Pipeline PFL from our MAOP validation and gathered the available documentation relating to the original 1957 installation of Line 147, Segment 109. The pipeline

SB_GT&S_0008232

engineer consulted with PG&E corrosion, metallurgical, and welding engineers to assist in determining the appropriate repair method, and developing a preliminary root cause of the leak. In addition, the pipeline engineer advised PG&E gas transmission planning engineers of the potential presence of the A.O. Smith pipe and its possible impact on any future pressure increase on Line 147.

32. On November 13, 2012, we repaired the leak with a 6-inch cap. The initial assessment by the field crew that repaired the leak and by the pipeline engineer for Line 147 was that the leak was caused by external corrosion.

33. On November 14, 2012, the pipeline engineer sent an email notification of the leak repair and his observation of a potential discrepancy with the PFL for Line 147 to various departments, including MAOP Validation, Integrity Management, Operations, PSEP, Hydrotest, and Gas Planning. He described that utilizing the currently accepted SMYS (33,000 psi) and joint efficiency (0.8) values for A.O. Smith pipe, per the latest version of PG&E's "Resolving of Unknown Pipeline Features" document, Line 147 would be operating at 55.3% SMYS in a class 3 location at an MAOP of 365 psig.

34. Based on this email, we took the following actions:

a. We investigated how the long seam was incorrectly identified as DSAW (further discussed in paragraphs 35-37, below).

b. We began a re-review of all pipeline specifications for Line 147 (further discussed in paragraph 39, below).

c. We concluded that applying a conservative joint efficiency factor of 0.8 rather than 1.0 for DSAW still resulted in an MAOP above 365 psig, but would require the pipe to operate "one-class-out" pursuant to the strength test provisions in 49 C.F.R. § 192.611 (further discussed starting at paragraph 54, below).

35. Segment 109, where we discovered the A.O. Smith pipe, was installed during a single construction job. Our MAOP validation documentation for this segment originally showed the long seam as DSAW. We determined that our engineer had mistakenly assumed

DSAW pipe when preparing the PFL in October 2011. This assumption led to the use of a joint efficiency factor of 1.0. In addition, the engineer failed to appropriately identify the long seam type as an assumption, which should have led to additional scrutiny by subsequent reviewers.

36. A joint efficiency factor of 1.0 is inconsistent with the conservative assumptions set forth in PG&E's Procedure for the Resolution of Unknown Pipeline Features (PRUPF). The PRUPF provides for an assumption of a joint efficiency factor of 0.8. In short, the engineer's assumption that the pipe was DSAW when preparing the PFL was contrary to PG&E's internal guidance.

37. Our MAOP validation process contained quality control steps designed to identify and correct human error in the preparation of a given PFL. However, it appears that the PFL for Line 147, Segment 109 was prepared without the appropriate quality control steps. Thus, it is likely the PFL was prepared and approved without the intended quality control.

38. Based on the identification of the A.O. Smith pipe, we updated the MAOP validation documentation using the lower SMYS value and lower joint efficiency factor. This resulted in lowering the MAOP for Segment 109 from 437 psig to 330 psig.

<u>Line 147, Segments 103, 103.1 and 103.6 (Record Discrepancy Errors)</u>

39. In mid-November of 2012, David Harrison, a former PG&E pipeline engineer and now a technical consultant working on our MAOP validation effort, directed his team to re-review the documentation and information obtained from construction activities on the entire Line 147. This re-review began at the western end of Line 147. The re-review observed that a transmission plat map on Line 147 included pipe sections with specifications (seamless and butt weld pipe) for the job that were inconsistent with the purchase order (only seamless pipe). The installation job for this section of Line 147 included Segments 103, 103.1 and 103.6. PG&E's MAOP validation documentation for these segments originally showed the pipe as "seamless." Although the original engineer who worked on Line 147 noted the inconsistency in 2011, the PFL erroneously characterized the pipe as seamless.

40. To conduct further analysis, in January 2013 we performed a field examination on an above ground span of pipe at mile point 0.52 on Segment 103.1 of Line 147. The initial field investigation indicated SSAW pipe. After the initial field investigation, Mr. Harrison requested that our Applied Technology Service department perform non-destructive testing on the open span to confirm the seam type.

41. On January 25, 2013, an employee from our Applied Technology Service went to the site and determined that the exposed span of pipe was SSAW. On January 29, 2013 Applied Technology Service issued a Pipe Characterization and Weld Assessment report for the exposed portion of Line 147 at mile point 0.52, and for a secondary location. The testing confirmed both sections were SSAW pipe.

42. We updated the MAOP validation documentation based on the 2013 determination that the seam type is SSAW. Segment 103 is in a class 1 location. Applying a conservative joint efficiency factor of 0.8 for SSAW pipe rather than 1.0 for seamless pipe, the design MAOP for Segment 103 changed from 590 psig to 495 psig. With this change, the segment was still commensurate with a 365 psig MAOP. Segments 103.1 and 103.6 are in class 3 locations. Due to application of the lower joint efficiency factor the design MAOP for these segments changed from 409 psig to 343 psig. By comparison, the 2011 strength test would support an MAOP for Segments 103.1 and 103.6 of 400 psig or above.

<u>Line 147, Segments 108 and 108.7 (Updated Information)</u>

43. Also in January 2013, Mr. Harrison and his team recognized that the Line 147, Segment 109 job with the A.O. Smith pipe was installed at approximately the same time as an adjacent job. The portion of Line 147 associated with the adjacent job includes Segments 108 and 108.7. Although no errors were found in the MAOP validation documentation for these segments, as described below, we did update the SMYS value.

44. The 1957 field pressure test report for these segments showed the pipe to be API 5LX Grade X42 (which has a 42,000 psi SMYS). PG&E's MAOP validation documentation originally showed the long seam as "unknown > 4 inch." Under the federal code, the joint

efficiency factor for unknown pipe greater than 4 inches in diameter is 0.8, and that is what our PFL reflected.

45. During their research, Mr. Harrison's team learned that portions of this adjacent job had been cut out as part of the 2011 hydrostatic testing process. On February 8, 2013 Mr. Harrison asked PG&E's hydrostatic testing group to have these large diameter portions of pipe examined to determine seam type and wall thickness.

46. At some time between February 27 and March 5, Mr. Harrison received photographs of four sections of pipe that had been cut out of Line 147 in connection with the strength tests. He was able to confirm from the photographs that the long seam for two sections of the pipe was DSAW. Another was seamless, and the fourth was SSAW.

47. Based on this, we updated the MAOP validation documentation for Segments 108 and 108.7, which had previously reflected a seam type of "unknown > 4 inch," to show the SSAW seam type. PG&E applies a joint efficiency factor of 0.8 for both "unknown > 4 inch" and SSAW pipe.

48. In 2012, we had performed destructive testing on the cut out portion of pipe. The testing confirmed a SMYS value of 42,000 psi. Despite this, we reduced the SMYS value to 33,000 psig in order to reflect a more conservative SMYS value based on the seam type and installation year. While this update did affect the MAOP for the two segments (reduced from 525 psig to 412 psig), these segments are still commensurate with an MAOP of 365 psig.

49. In sum, the MAOP records for six segments of Line 147 were revised, four of them to correct errors.

Date of Discovery/ Analysis	Segment Number	Prior MAOP	Revised MAOP	Reason for Change	Commensurate with 365 psig?
Oct '12 – Nov '12	109	437 psig	330 psig	Human Error	No
Nov '12 – Jan '13	103	590 psig	495 psig	Record Discrepancy Errors	Yes
Nov '12 – Jan '13	103.1	409 psig	343 psig		No
Nov '12 – Jan '13	103.6	409 psig	343 psig		No

Jan '13 – Mar '13	108	525 psig	412 psig	Updated Information	Yes
Jan '13 – Mar '13	108.7	525 psig	412 psig		Yes

<u>Ongoing Analysis and Corrective Action</u>

50. In early 2013, the pipeline engineer for Line 147 decided to combine the excavation and root cause investigation of the Segment 109 leak with the clearance for our Commercial Way/Edgewood Station Valve Automation project. The goal was to maximize clearance resource efficiencies, minimize reliability risks to the Peninsula gas transmission system, and minimize blowdown gas and resulting potential for negative environmental impacts. The clearance was originally scheduled for earlier in the off-peak season but delays in the Commercial Way Valve Automation project postponed the Line 147 root cause pipe removal until early August 2013.

51. With the leak repaired in November 2012, there was no safety issue, but we wanted to determine the root cause of the leak to help inform our future assessments and maintenance. On August 9, 2013, we removed the portion of Segment 109 pipe on Line 147 that had leaked. We sent the removed pipe section to Anamet, Inc., an independent laboratory. Among other things, we asked Anamet to determine the root cause of the leak through testing and examination. On August 19, 2013, we received a report from Anamet on the tensile testing and metallurgical examination of the section of pipe. Anamet's report states that "the weld appears to be an A.O. Smith type weld" and shows that the longitudinal weld of the tested pipe had a tensile strength supporting a 1.0 joint efficiency factor. The root cause testing and examination are still in progress and have not yet been completed.

52. As mentioned above, we have continued to refine our MAOP validation processes in the time since the PFL for Line 147 was prepared. We have implemented several enhancements and procedures that will help minimize preventable errors. Some of these improvements include:

a. *Additional independent third-party review*: In December 2011, we expanded the independent third-party quality assurance process for the MAOP Validation Project to include the engineering analysis process. This is the portion of the MAOP validation process in which the engineer makes judgments and reaches conclusions about which assumptions to apply. This is the part of the process in which the error for Line 147, Segment 109 was made.

b. *Testing and validation of conservative engineering assumptions*: We implemented additional controls to test and validate engineering assumptions applied in connection with the MAOP validation process. These controls enable us to: (i) identify all instances where an engineering assumption has been applied; and (ii) confirm that such assumptions are consistent with our conservative engineering standards.

- By way of explanation, two of the primary steps in the MAOP validation process are creation of the PFL from available source records (called the "PFL build") and the subsequent engineering analysis of the completed PFL. One significant quality control enhancement involves an automated comparison of values in the PFL, which come directly from available source documents, to the values applied in the subsequent engineering analysis. When values do not match (for example, an "unknown" SMYS in the PFL as compared to a 33,000 SMYS applied in the engineering analysis) they are identified in our database as assumptions rather than confirmed values from source records. This helps us trace the source for each specification used in the PFL.
- We test all identified engineering assumptions by comparing them against our conservative engineering standards. A feature's MAOP cannot be formally validated until assumptions that do not match our engineering standards are explained by the engineer applying the assumptions and/or

validated by an engineer conducting subsequent quality control. For example, an assumed joint efficiency of 1.0, rather than the more conservative 0.8, would require further analysis and confirmation by an engineer before that value can be used to validate the MAOP of the feature in question. This reduces the potential for human error by confirming that an engineering rationale supports all assumptions that deviate from our standards.

c. *Engineering data validation tool*: We have also implemented ways to identify and eliminate inaccuracies in our historical pipeline data. Our new data analysis tool allows our engineers to identify values across all PFLs that are inconsistent with our historical procurement standards and/or inconsistent with known historical pipeline manufacturing techniques. For example, this tool will identify all PFL values indicating seamless pipe of a vintage and diameter that we have not historically purchased and flag any exceptions within the PFL.

- We also continue to apply the findings from field excavations to confirm the accuracy of our existing records and validate our conservative engineering assumptions.

53. We are confident that these process enhancements mitigate the risk of human error going forward. These processes also enable us to identify and correct discrepancies in our underlying pipeline records.

<u>Use of Strength Test Results to Establish MAOPs "One Class Out"</u>

54. The updated information discovered on Line 147 prompted us to review whether Line 147 was operating at an MAOP commensurate with its class and whether it could be operated one class higher ("one class out") under Section 192.611 of the federal code.

The Federal Code

55. Generally, the federal regulations require a greater margin of safety for pipelines operating in more heavily populated areas. The safety margin is defined by the allowed percentage of the SMYS of the pipeline in different class locations. Pipelines that experience a class change, are in satisfactory condition, and have been strength tested for a minimum of 8 hours at a sufficient pressure may be operated at the percentage of SMYS applicable one class lower. *See* 49 C.F.R. § 192.611(a). These pipelines are said to be operating "one-class-out." Thus, under Section 192.611, a pipeline now in a Class 3 area with an appropriate strength test could operate up to 60% of SMYS (the Class 2 limit) instead of being restricted to 50%, the usual limit for Class 3. The table below illustrates how the one-class-out provisions work:

	Maximum Allowable Operating Stress Level (% SMYS)	
Class Location	**Typical**	**One-Class-Out per 192.611**
1	72%	N/A
2	60%	72%
3	50%	60%
4	40%	50%

56. From an engineering standpoint, a more recent test performed under Subpart J of the federal code would provide greater confidence than an older one. Historically, PG&E had interpreted Section 192.611 to allow a pipeline to operate one-class-out as long as it had been subjected to a valid Subpart J strength test for eight hours in a different year than the year the pipe was installed.

57. Starting in late 2012, our Gas Operations group began discussions with PG&E's Law Department about the interpretation of Section 192.611. The evaluation and analysis was intended to ensure that PG&E was accurately and conservatively interpreting the federal code. PG&E is providing this summary of its current interpretation subject to, and without any intent to waive, the attorney-client privilege.

58. As a result of the analysis conducted from late 2012 into 2013, PG&E now believes that the combination of since-repealed Section 192.607 (repealed in 1996) and 192.611(a) precludes gas operators from relying upon a post-1974 strength test to operate a segment one-class-out if that segment changed up in class before April 15, 1971.

59. Adopted in 1970, Section 192.607 required operators to make an initial determination of class location designations for all pipeline segments operating at a hoop stress greater than 40% of SMYS and to confirm or revise the MAOP for each of those segments. Section 192.607 required operators to complete a system-wide study by April 15, 1971, to determine: 1) the present class location of all segments operating at a hoop stress greater than 40% SMYS; and 2) whether each segment was operating commensurate with its present class location. Operators were then required to confirm or revise the MAOP for each non-commensurate segment pursuant to Section 192.611 no later than December 31, 1974. (The initial deadline was January 1, 1973, but Congress extended it to December 31, 1974.) In essence, Section 192.607 required all operators to "true up" their class locations and corresponding MAOPs by December 31, 1974. As a result, PG&E came to the conclusion that it cannot rely on a post-1974 strength test to operate a segment one-class-out if that segment experienced a class change prior to 1971. We reached this conclusion, not as a matter of public safety, but based on a strict reading of the federal code sections. From a public safety standpoint, the more recent the strength test – regardless of when the class location changed – the better.

60. The following table summarizes how the code works for class changes pre- and post-1971:

	Maximum Allowable Operating Stress Level (% SMYS)		
Class Location	Pre-1971 Class Change		Post-1971 Class Change
	Strength Test Per 192.611 (1971-1974)	Strength Test Per 192.611 (post-1974)	Strength Test Per 192.611
2	72%	60%	72%
3	60%	50%	60%

4	50%	40%	50%

Thus, under the code, all pipe experiencing a class change may operate one class out except pipe changing class before 1971 with a strength test after 1974.

61. As an example: Assume a segment of pipe installed in a Class 2 location operating at an MAOP of 360 psig (60% of SMYS) that changed to Class 3 in 1969. If we strength tested that pipe to 540 psig (1.5 times MAOP) in 1973, we could operate it one-class-out with an MAOP of 360 psig (60% SMYS). If, on the other hand, we strength tested the pipe 40 years later – in 2013 – to 540 psig or even higher, we could only operate it at an MAOP of 300 psig (50% SMYS) solely because the strength test did not occur before December 31, 1974. This is the case even though, from an engineering and public safety perspective, the more recent pressure test would have more value than the 1973 pressure test.

Line 147

62. Applying our historical interpretation of the code, and relying on the 2011 strength test, Segments 109, 103.1 and 103.6 of Line 147 could operate one-class-out without a decrease in MAOP based on the newly-determined 0.8 joint efficiency factor. However, as discussed above, our interpretation of the code has changed, and we are no longer relying on the 2011 strength test to be able to operate one-class-out.

Line 101

63. Applying our revised interpretation of the one-class-out provisions and analyzing the pipeline, we determined that segment 167.2 of Line 101 had changed class prior to 1971 and was strength tested after 1974. That segment is in Millbrae (0.44 miles) and changed to Class 3 in approximately 1952. The segment had a strength test to 650 psig in 1989, which would support an MAOP of 433 psig in a Class 3 location.

64. The MAOP validation records we submitted to the Commission in October 2011 showed this segment capable of operating at 60% SMYS with a MAOP of 396 psig, and indicated it was "operating in class" in light of the strength test and per our historical application of the code. However, because the 1989 strength test cannot be used to allow the segment to

operate one-class-out (i.e., as in a Class 2 location, between 50 and 60 percent SMYS), then the segment was not operating in class and has an MAOP of 330 psig.

Contacts with SED and Corrective Actions

65. On February 22, 2013, PG&E contacted the Commission's staff to arrange a meeting regarding PG&E's one-class-out analysis, among other topics.

66. On March 20, 2013, Frances Yee, our Director of Gas Regulatory Compliance & Support, and Joe Medina, our Director of Transmission Process & MAOP Validation, had a conference call with SED. Among the topics discussed were the corrected pipe specifications for Line 147 and the application of the one-class-out analysis to Lines 147 and 101. We shared the information on the attached two-page handout with SED, and emailed the handout to SED.

67. That handout also included information regarding Line 131. At the time, we were investigating certain sections of Line 131 near Fremont that we believed may have experienced a pre-1971 class location change. Subsequent to the meeting with SED, on July 2, our Gas Engineering department determined that the relevant sections of Line 131 were not affected by our corrected one-class-out interpretation.

68. During the March 20 discussion, SED requested the MAOP Validation Reports for lines 147 and 101, the PFL for Line 147 and the original MAOP validation records for Line 147. We provided SED with the requested material on May 2 and May 8, 2013. Our May 8th communication also advised that "PG&E is still conducting a review for any other lines that may be impacted by our one-class-out policy change and will submit that report to you when the review is completed."

69. We will provide SED with our system-wide analysis of all lines affected by the application of Section 192.607 (including proposed corrective actions where necessary) as soon as that analysis is complete.

70. On April 3, 2013, we reduced the operating pressure of Line 101 to below 300 psig, where it has remained. However, the MAOP for this line is properly 330 psig, and, if winter operating conditions require it to serve customers, we plan to operate up to that MAOP.

71. Line 147 has been operating below 300 psig since May 2012 and Line 101 since April 2013. Nevertheless, we have formally lowered the MAOP of the impacted segments of Lines 101 and 147 from 365 psig to 330 psig.

72. We are working on a project to expedite the installation of a regulator station at Aviador Avenue in Millbrae, approximately 0.75 miles upstream (south) of Lomita Park Station. The regulator station will function to isolate the affected portion of Line 101, such that the upstream sections from Milpitas Station to the regulator station may operate at 365 psig and the downstream sections, including the affected portion, would operate at 330 psig.

73. Although we have revised the MAOP of segment 167.2 of Line 101 downward, we plan to replace the affected portion so that we can operate Line 101 up to 365 psig. Subject to obtaining the necessary environmental permits, the work is now planned for 2014-15.

74. Line 147 will continue to remain isolated from Line 101 to maintain its operation at the lower MAOP of 330 psig.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge and belief.

Executed this 30th day of August 2013, at San Ramon, California.

M. Kirk Johnson

Investigation of Class Location Issues

28 Feb 2013

Historical Policy

- A pipeline could operate "one class out" as long as there was a valid pressure test for 8 hours at over 90% SMYS in a different year than the install year.
- Implemented in the MAOP validation in early 2011.

Class Location Study in 2011

- Requirement for 90% SMYS test removed.
- Allowed the pressure test year to be the same as the installation year.
- MAOP validation code modified to match this policy.

2013 Legal Interpretation

- As of 1/1/1973 all pipelines should have been brought up to the code requirements at the time.
- Any pipeline installed prior to 1973, that had a class location change prior to 1973 and was not properly tested prior to 1973, cannot be operated, "one class out".
- When class change occurs we have 2 years to make it commensurate, (typical situation).
- After 1973, when a class location change has been **discovered**, we must begin action to make the pipeline commensurate with the class location or qualify the line to operate "one class out".
- If we discover pipeline **specifications** that are different from our original understanding, this is not a change in class location and the pipeline cannot be operated "one class out".

The impact on the CPUC Pressure Restoration Pipelines are detailed in the following table.

Route	Location	Length (miles)	OD (inch)	Install Year	Test Year	MAOP *	% SMYS @ MAOP	Test Press	Curr. Press	% SMYS @ Curr. Press	Comments
101	San Bruno border, near SFO	0.7	20	1949	1989	365	55.3 %	650	365	55.3 %	Was operating one class out in 101 pressure restoration submittal, known at time of submittal Class change in 1952, scheduled for late 2013 replacement. Engr started.
147	San Carlos – Redwood City	1.1	24 and 20	1947	2011	365	53 %	685	300**	43.5 %	2 sections of newly discovered pipe specifications less than expected. Part of 101 pressure restoration filing and was **not** noted in filing. Class changed 1951. No planned replacement.***
131	Fremont – 880 Interchange	0.1	30 and 34	1954 and 1957	1992	590	57 % elbows 54 % pipe	911	590	57 % elbows 54 % pipe	Pipe and elbows in Hwy 880 clover leaf and under over pass. Known and included in 131 pressure restoration filing. No planned replacement.***

Notes:

* MAOP of these pipelines as authorized by CPUC.

**Line 147 is a cross tie and has been operating at a lower pressure due to the current line configuration. Actual regulator set points will be slightly lower.

*** With favorable permitting we could potentially replace these pipes in late 2013. More likely 2014.