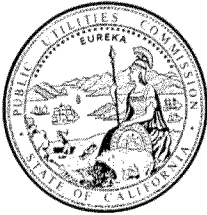


Docket: : R.11-02-019
Exhibit Number : _____
Commissioner : M Florio
Admin. Law Judge : M Bushey
SED Project Mgr. : Darryl Gruen
:



**SAFETY & ENFORCEMENT DIVISION CALIFORNIA
PUBLIC UTILITIES COMMISSION**

**REPORT AND TESTIMONY
OF MARGARET FELTS**

R.11-02-019

San Francisco, California
November 18, 2013

1 I. Introduction

2 My name is Margaret C. Felts. My Company name is M.C. Felts Company and my
3 business address is 8822 Shiner Ct., Elk Grove, CA 95624. I am a technical consultant
4 specializing in energy and environmental issues.

5 I have been the lead technical consultant on cases involving pipeline integrity and facility
6 management records and processes, including the PG&E San Bruno pipeline explosion
7 investigation, the Pacific Offshore Pipeline Company gas plant startup failure involving a high
8 pressure release of gas containing toxic levels of hydrogen sulfide, and the Mohave coal slurry
9 plant failure and explosion of a high pressure steam pipe.

10 At various stages during my career, I have been responsible for engineering and
11 management of gas, oil, water supply, and waste water pipelines. Projects range from
12 engineering design to leak detection, in line inspections, and pipeline removals.

13 A copy of my Curriculum Vitae is attached hereto.

14 I am sponsoring this testimony on behalf of the Safety and Enforcement Division of the
15 California Public Utilities Commission. In accordance with the ALJ's ruling at the October 21,
16 2013 prehearing conference, this testimony focuses on evidence and circumstances related to
17 PG&E's Line 147. (Prehearing Conference Transcript, p.78, l. 1-13 and p. 85, l.17-20) As noted
18 below in the discussion of individual Line 147 safety concerns, these issues also can and should
19 be applied to PG&E's broader gas transmission system. SED will submit additional testimony
20 analyzing the broader OSC issues in those subsequent proceedings.

21
22 II. The Maximum Allowable Operating Pressure For Line 147

23 The Report of Sunil Shori contains the recommendation of the Safety and Enforcement
24 Division regarding the permissible Maximum Allowable Operating Pressure for Line 147.

25
26 III. PG&E did not find the actual leak and, therefore, cannot identify its Root Cause, leaving
27 open the question of the integrity of remaining A.O. Smith pipe in Line 147.

28 In October 2012, PG&E field workers detected a gas leak on Line 147. PG&E welded a 6
29 inch diameter cap over the area believed to be the site of the leak and later removed a 9 ft piece
30 of pipe that included the 6"cap for laboratory testing. In spite of examination by two contract
31 labs, and PG&E's own ATS lab, PG&E could not locate the site of the leak, and still cannot

1 today. As a result of the leak investigation, however, it was discovered that the pipe was 1929
2 A.O. Smith pipe, which had been installed at the site in 1947, after previous use in another
3 location. In fact, A.O. Smith pipe runs for ¼ mile (1,395 ft.) in Line 147.

4 PG&E has not clearly acknowledged that the exact site of the leak remains undetected.
5 PG&E continues to suggest, by referring to laboratory results, that there is a valid root cause
6 analysis. In fact, the laboratory reports do not identify the site of a leak and thus, by definition,
7 their reports cannot identify a root cause of that leak. PG&E attempts to focus attention on the
8 unanswerable question of what caused the leak, while failing to openly acknowledge that the
9 leak was never located. Thus, PG&E invites debate on a question that cannot have a meaningful
10 answer.

11 Because PG&E was not able to locate or, therefore, to analyze the site of the October
12 2012 leak, that incident cannot provide specific useful guidance about vulnerabilities that may
13 exist on these 1,395 ft. of A.O. Smith pipe in Line 147. Equally important, that incident and the
14 subsequent failed efforts to analyze it cannot provide any reassurance about the integrity of the
15 remaining A.O. Smith pipe installed elsewhere in the system.

16 Evidence related to these issues is addressed below.

17 On October 13, 2012, a leak was discovered on Line 147.

18 “On the same day, a leak surveyor investigated the potential leak, but was
19 unable to obtain a useable reading with his gas detection device due to the
20 accumulation of water and mud from the nearby water main break. The
21 leak surveyor returned to the site on the morning of October 15, 2012, and
22 was able to confirm the leak.”¹

23 The leak surveyor then remained on site until arrival of the construction crew, as discussed in
24 paragraph 26 of PG&E’s Verified Statement.² PG&E’s construction crew drilled holes,
25 measured the gas concentrations and changed the leak from a grade 1 (immediate response) to
26 grade 2+ (respond within 90 days).³

¹ 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, August 30, 2013, para. 25

² Ibid, para. 26

³ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch538 (A-Form)

1 On October 18, 2012, a PG&E crew exposed the Line 147 pipe in the area of the leak. In
2 his Verified Statement, PG&E’s Vice President, Kirk Johnson, states that the pipeline engineer
3 on site visually investigated and realized the long seam weld of the exposed section of pipe
4 appeared to be A.O. Smith variety.⁴ Mr. Johnson does not say when, how or by whom the
5 location of the leak was determined.⁵

6 On November 13, 2012, PG&E repaired what it thought was the source of the leak by
7 welding a 6” cap over the assumed site, then covered the pipe without doing the x-rays and other
8 analytical inspections that PG&E engineers had requested.⁶

9 Nine months later, on August 9, 2013, PG&E excavated the leak site and removed a
10 portion of the line where the cap was welded to the pipe and sent the piece of pipe to the
11 Anamet, Inc. laboratory for a Root Cause analysis.⁷ Anamet, Inc. could not find the leak and, in a
12 report to PG&E, stated:

13 “Please take a look at the attached photos. After cleaning, I put developer on the
14 inside of the section and penetrant on the outside within the sectioned PLiDCO
15 cap. No leak path was detected. There is a crack like feature on the inside surface.
16 Do you want me to roll the dice and do some sectioning, or would you like to
17 have your guys do RT⁸ first?”⁹

18 The Anamet, Inc. Report findings include:

⁴ 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, August 30, 2013

⁵ GasPipelineSafetyOIR_DR_SED_007-Q08: In response to the question, how did PG&E identify the location of the leak, PG&E responds “PG&E field personnel detected the leak location using a leak survey tool called a Combustible Gas Indicator.”

⁶ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch467, and GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch489

⁷ A root cause analysis is an investigation where the cause of or reason for a particular anomaly or condition is determined. In this context, the root cause analysis would determine as precisely as possible the metallurgical conditions present that created the identified leak. -- Declaration of Sumeet Singh, September 13, 2013, para. 4, Supporting the Verified Statement of PG&E V.P. of Gas Transmission Maintenance and Construction in Response to Ruling of Assigned Commissioner and Assigned Administrative law Judge, August 30, 2013, para. 51; also GasPipelineSafetyOIR_DR_DRA_086-Q02Atch01

⁸ RT means Radiographic Testing

⁹ _GasPipelineSafetyOIR_DR_DRA_086-Q22Atch068 (email from Assoc. Director of Laboratories to PG&E Engineer (GT&D); GasPipelineSafetyOIR_DR_DRA_086-Q22Atch157 (23 Sept – 2nd version; note: 1st version was provided as 1 to the Verified Statement, September 6, 2013)

1 “As shown in Figure 10 through Figure 20, a weld crater crack extended
2 from the outside surface into the weld heat affected zone in section 1a, but
3 did not penetrate through-wall at this location.”¹⁰

4
5 “In section 1b, shown in Figure 13 through Figure 15, cracks were present
6 from the outside surface to the inside surface. Only a few ligaments
7 prevented the demonstration of a through-wall leak path.”¹¹

8
9 “In section 1c, shown in Figure 16 through Figure 18, one small ligament
10 at the outside surface prevented demonstration of a through-wall leak
11 path.”¹²

12 In its apparent frustration at not being able to find the leak, PG&E devised a pressure test,
13 which was performed on the sample pipe by Anamet, Inc. in the laboratory.¹³

14
15 “A pressure test was performed by clamping a plate over the sectioned
16 cap, sealed with a silicone gasket, and introducing 40-psig of compressed
17 air. Snoop® liquid leak detector was applied to the inside surface. No
18 leaks were detected. The compressed air was valved-off, and no pressure
19 drop from 40 psig was detected after 45 minutes.”¹⁴

20 Because it could not find the leak, Anamet, Inc did not perform a Root Cause Analysis.
21 Instead, Anamet provided a qualified conclusion:

22 “Metallography revealed a leak path was likely present under the PLIDCO
23 cap between an external weld crater crack and liquation cracks in the
24 underlying weld heat affected base metal.”¹⁵ (Underline added)

25 PG&E sent the pipe to its own lab, ATS for further analysis. PG&E’s Principal Corrosion
26 Engineer wrote:

27 “Pls arrange for someone to shoot this part to locate the leak. You can do
28 at Anamet or bring back to ATS and do it? Then run it back to Anamet.
29 Which would you prefer? As usual we need it quickly. Work at Anamet
30 stops until we locate the leak.”¹⁶ (Underline added.)

¹⁰ GasPipelineSafety OIR_DR_SED_005-08Atrch02, Anamet, inc. Report No. 5004.9268, Sec. 2.2 Metallography, p. 3 (includes high resolution color photos)

¹¹ Ibid.

¹² Ibid.

¹³ GasPipelineSafetyOIR_DR_DRA_086-Q22Atrch078

¹⁴ GasPipelineSafety OIR_DR_SED_005-08Atrch02, Anamet, inc. Report No. 5004.9268, Sec. 2.1 Visual Examination, p. 2

¹⁵ Ibid, Sec. 3.0 Conclusions, p.4

¹⁶ GasPipelineSafetyOIR_DR_DRA_086-Q22Atrch078, p. 2. *Note:* “Shoot” is reference to some unspecified inspection technique, such as x-ray.

1 In late September 2013, PG&E sent the same pipe section to Exponent, Inc. to conduct an
2 independent review of the Anamet report and to perform additional analysis.¹⁷ Exponent
3 confirmed the Anamet analysis,¹⁸ and was also unable to find the leak. The Exponent, Inc. report
4 includes the following:¹⁹

5 “As shown in Figure 5, the pre-existing crack in Sample A-1-1-8 only
6 extended from the OD approximately halfway through the pipe wall. The
7 pre-existing crack A-1-1-7 extended from the ID nearly to the OD surface.
8 While neither of these two samples display a clear ID-to-OD leak path, the
9 pre-existing crack in Sample A-1-1-7 extends nearly through the pipe wall
10 thickness.”²⁰ (Underline added.)

11 The above finding is inconsistent with the conclusions listed at the end of the Exponent
12 Report, which state that there was a leak.²¹

13 Thus, after what appears to have been a thorough examination of a 6 inch diameter
14 circular area on the Line 147 pipe body, PG&E has not been able to prove that this piece of pipe
15 was in fact the source of the leak that was detected in October 2012. Nevertheless, when asked
16 about the root cause of the leak, PG&E said:

17 “The original root cause of the leak was identified under difficult field
18 conditions as external corrosion - this is what was on the A-form. It was
19 not the result of a laboratory examination or a test. After cut out and lab
20 analysis the cause was determined to be “Material Failure” due to the weld
21 metal cracking in the base metal.”²²

22 When PG&E was asked what evidence it can point to in the Anamet Report that confirms the
23 leak detected was in fact in the area beneath the PLIDCO cap had been welded to the pipe,
24 PG&E responded:

25 “The entire report speaks to that issue. Specifically figures 16, 17, and
26 Appendix A, identify nearly 100% through wall cracking.” (Underlining
27 added.)

¹⁷ GasPipelineSafetyOIR_DR_DRA_086-Q22Atch149

¹⁸ GasPipelineSafetyOIR_DR_DRA_087_Q48; GasPipelineSafetyOIR_DR_DRA_086-Q22Atch189;
GasPipelineSafetyOIR_DR_DRA_086-Q22Atch145

¹⁹ GasPipelineSafetyOIR_DR_DRA_086-Q22Atch070, GasPipelineSafetyOIR_DR_DRA_086-Q22Atch191

²⁰ GasPipelineSafetyOIR_DR_DRA_086-Q22Atch191, p. 7

²¹ GasPipelineSafetyOIR_DR_DRA_086-Q22Atch191, p. 22

²² GasPipelineSafetyOIR_DR_DRA_086-Q39 e.

1 Of course, any crack that did not go 100% through the pipe wall could not have been the
2 site of the leak.

3 PG&E also searched its records to find evidence of a prior leak that had been
4 repaired at the location it thought to be the source of the leak, which would explain the
5 purpose of the weld material found on the 1929 pipe. No such records were found.²³

6 Recently, DRA asked PG&E: what was the most probable cause of the leak according to
7 PG&E engineers reviewing this leak and the Anamet report? PG&E responded:

8 “PG&E concurs with the probable cause conclusion in the Kiefner &
9 Associates “Current fitness for service of Line 147” letter, provided as
10 Appendix G to the October 18, 2013 Statement of Sumeet Singh (R.11-02-
11 019).”²⁴

12
13 However, a word search of the Keifner letter quoted above, written by Mr. Rosenfeld, reveals no
14 occurrences of the phrase “probable cause.”²⁵ The word “cause,” appears, but in a context
15 completely unrelated to PG&E’s response. In fact, none of Mr. Rosenfeld’s conclusions discuss
16 the cause of the leak.²⁶

17 Finally, PG&E had an opportunity, when the Line 147 pipe trench was open in October
18 and November of 2012, to investigate the condition of the longitudinal and circumferential welds
19 in the area where the leak had been detected. But, despite the Consulting Engineer’s requests to
20 inspect the welds, PG&E buried the line without performing the requested radiographs.²⁷

21 To determine the root cause of a leak, PG&E must first identify the location and type of
22 leak. A leak is a through-wall crack or hole in the pipe. The importance of identifying the exact
23 source of the leak in the pipe or pipe weld and then performing a root cause analysis of that leak
24 is to determine if similar pipe, subjected to the same operating conditions, also could contain
25 unstable cracks that might present a safety risk. Based on the data provided by PG&E, including
26 the test reports by Anamet and Exponent, PG&E never found the exact location of the Line 147
27 leak that field personnel detected using gas detection equipment in October 2012. Therefore,

²³ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch528

²⁴ GasPipelineSafetyOIR_DR_DRA_087-Q46

²⁵ At some point in discovery, the phrase “probable cause” appears to have replaced “root cause.” A word search of the Keifner Letter for “root cause” also returned no occurrences of the phrase.

²⁶ Kiefner & Associates “Current fitness for service of Line 147” letter, provided as Appendix G to the October 18, 2013 Statement of Sumeet Singh (R.11-02-019), p. 1

²⁷ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch467

1 PG&E was unable to perform a Root Cause Analysis and does not know if there are unstable
2 cracks in other parts of Line 147 that could fail under stress.²⁸

3 Recommendation: PG&E should replace the AO Smith and SSAW pipe identified in
4 Line 147.

5

6 IV. L-147 MAOP calculations must take into account risks posed by the system-wide
7 disarray of PG&E's pipeline records.

8 In D. 11-06-017 (p. 8), the Commission quoted a PG&E Vice President who stated that,
9 prior to doing a hydrostatic test, it is important to know the components of the pipeline to be
10 tested:

11 "What you want to know is everything that's in the ground before you
12 start conducting that test so that you don't put yourself in a situation where
13 you've led to unintended consequences by pressuring that pipe up."

14 The Vice President went on to explain that, with regard to seamed pipeline, where adequate
15 records are not available regarding the strength of the longitudinal weld, PG&E would dig up the
16 pipe and verify the condition of the weld. PG&E offered its validation for Line 101 as an
17 example of how it intended to approach issues of missing records.^{29 30} Had PG&E pursued this
18 strategy, it would have found the A.O. Smith pipe in Line 147 prior to hydrotesting the line in
19 2011 and would have run the hydrotest to a safer, lower peak pressure. Accurate records are
20 needed to calculate MAOP and also to safely conduct pressure tests, as PG&E's vice-president
21 testified.³¹ In the absence of these records, truly conservative assumptions must be made.

22 The surprise discovery of reused pipe in Line 147 during a leak investigation highlights
23 the continued safety risks to PG&E's employees and the public posed by the continuing disarray
24 in PG&E's pipeline records. Three of the highest priorities are discussed below.

25

²⁸ Applies generally to other 1929 A.O. Smith pipe in the transmission system (247 miles, see Section IV.A below).

²⁹ D.11-06-017 at 8 – 9, Response to DRA DR 86 Q 32

³⁰ D.11-06-017, p. 94-95

³¹ D.11-06-017, p. 95

1 **A. Risk 1 – PG&E’s failure to apply appropriate conservative assumptions for all**
2 **“unknown” features poses a serious risk.**

3 In PG&E’s Pipeline Features List (PFL) “Build” database the word “unknown” is
4 pervasive in entries relating to vintage pipe installed before 1970.³² The inability to identify the
5 type of pipe in the ground seems to be the most critical problem for PG&E. Each pipe with
6 “unknown” characteristics (features) represents a potential site for PG&E to discover inferior
7 pipe, like the one recently found on Line 147. This lack of information prevents PG&E from
8 accurately determining pipeline MAOPs that are safe and that will support the service level
9 necessary for PG&E to provide service to its customers. Maximum hydrotest pressures are
10 selected based on the design MAOP, which is calculated using pipe characteristics (data). Thus,
11 it is important to deal with the problem of “unknown” data as soon as possible.

12 In this proceeding, PG&E produced a contract showing that it had purchased A.O. Smith
13 pipe in 1929,³³ and seems to represent this contract as the source of the pipe found in Line 147.
14 The contract shows PG&E received 247 miles of pipe. Most of that pipe is probably still in the
15 PG&E transmission system somewhere. In addition to this A.O. Smith pipe, there are hundreds
16 of miles of other vintage pipe in PG&E’s transmission system, some of which has been moved
17 from one location to another.

18 PG&E purports to recognize the significance and importance of using the most
19 conservative assumptions when actual data is unknown and is accumulating records of
20 reused pipe in a database that has grown to almost 300 rows of data.³⁴

21 “PG&E does not in all instances know where reconditioned pipe has been
22 placed in its transmission system. In the building of its Pipeline Features
23 List (PFL), PG&E has been gathering this information where it is
24 available.”^{35[1]}

³² PG&E’s Supporting Information for Safety Certification of Lines 147 Pursuant to Ruling of Assigned Commissioner and Assigned Administrative Law Judge, Exhibit B, October 16, 2013

³³ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch408

³⁴ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475, p. 4-5

³⁵ I.11-02-016, Pacific gas and Electric Company’s Response to the Consumer Protection and Safety Division’s Reports: Records Management Within the Gas transmission Division of PG&E Prior to the Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010 and Report and Testimony of Margaret Felts Testimony of Witnesses, p. 3-32.

1 However, there is no assurance that errors like the one that occurred on Line 147
2 have not occurred throughout PG&E’s PFL process, especially for High Consequence
3 Area (HCA) lines, which were the first lines to be documented using the early PFL
4 procedures. It is important that PG&E correct the errors. However, the Commission may
5 want to prioritize certain projects based on experience with Lines 132 and 147.

6 To identify the highest priority for action, consider the similarities between the
7 San Bruno Line 132, Segment 180 project and the San Carlos Line 147, Segment 109
8 project. Both projects were in-house construction (not installed by a contractor), built in
9 the 1956-1957 period and were constructed of salvaged materials of unknown origin and
10 operational history. The pipe was characterized as seamless in the GIS and IM
11 databases.³⁶ PG&E cannot find the original project file for either of these installation
12 projects.³⁷ Any pipelines sharing all or some of these characteristics should be given
13 special consideration.

14 **B. Risk 2 – PG&E’s data errors result in incorrect MAOP calculations for Line 147.**

15 The NTSB noted the importance of records for calculating MAOP in its instructions to
16 PG&E:

17 “ . . . It is possible that there are other discrepancies between installed pipe
18 and as-built drawings in PG&E’s gas transmission system. It is critical to
19 know all the characteristics of a pipeline in order to establish a valid
20 MAOP below which the pipeline can be safely operated. The NTSB is
21 concerned that these inaccurate records may lead to incorrect MAOPs.”³⁸

22 Accurate data or the most conservative assumptions are required to calculate a
23 valid MAOP.³⁹ However, in cases where pipeline data was unknown, PG&E’s PFL
24 system may not have produced the most conservative assumptions.⁴⁰

³⁶ P3-20060 from PG&E rolling production

³⁷ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475

³⁸ NTSB Safety Recommendation P-10—2, -3 (Urgent) and P-10-4, January 3, 2011, at 2

³⁹ 49 CFR 192.505

⁴⁰ This section focuses on PG&E’s PFL system. A broader concern is that PG&E is using multiple databases that should contain the same set of data for its pipelines. Instead, it appears that the multiple databases contain different data (and assumptions) for similar pieces of pipe. Some of the data bases PG&E refers to are: PFL, GIS 2.0, GIS 3.0, Intrepid, Integrity Management and eGIS. Further, it appears that the corrections to GIS 2.0 that originated from field personnel and engineers (as reflected in the Change Log that PG&E provided in the Recordkeeping OII) may not be migrated to other data bases.

1 PG&E created a procedure to help engineers fill in assumptions for pipe with unknown
2 PFL data. The procedure, as produced by PG&E is in draft form, although the process of filling
3 in features list assumptions for HCA pipe was concluded at the end of 2011. The draft, dated
4 October 9, 2013, is titled “Procedure for the Resolution of Unknown Pipeline Features”
5 (PRUPF).⁴¹ PG&E states that it uses Gas Standard and Specification A-11 (SP A-11) to assign
6 joint efficiency factors for various pipeline seam types, including single submerged arc welded
7 pipe.⁴² SP A-11 is titled “Identification of Steel Pipe” and provides information about features of
8 different types and vintages of pipe. It is incorporated into the PRUPF.⁴³

9 In some instances, a flaw in PG&E’s PRUPF prevents PG&E from accurately assigning
10 assumptions to unknown pipe when the pipe is reused. The PRUPF process of assigning
11 assumptions is based on knowing, or accurately estimating, the purchase date of the pipe. The
12 “look-up” tables provided in PG&E’s PRUPF procedure provide values to assign as assumptions
13 in the Pipeline Features List in place of data that is unknown. The flaw occurs because these
14 tables are keyed to the purchase date of the pipe. PG&E reasoned that no pipe would have been
15 kept in storage yards for more than 10 years. Therefore, the most conservative assumed purchase
16 date would be 10 years earlier than the “install date.”⁴⁴ Thus, for a pipe installed in 1957, the
17 assumed purchase date would be 1947.⁴⁵

18 The problem created by the 10-year storage assumption, when the unknown pipe happens
19 to be reused pipe, is illustrated by the case of Line 147, segment 109, which was installed in
20 1957. Based on the 10–year-storage assumption, PG&E engineers assumed the pipe had been
21 purchased in 1947, when in fact it had been purchased in 1929. Because PG&E did not purchase
22 A.O. Smith pipe in the late 1940s, PG&E’S 10-year-storage assumption excluded the possibility
23 that the unknown pipe installed in 1957 could be 1929 A.O. Smith pipe.⁴⁶

24 In the case of Line-147, the 10-year-storage assumption suggested the pipe would have
25 been purchased in 1947, thus it might have been SSAW pipe. PG&E has explained that SSAW

⁴¹ GasPipelineSafetyOIR_DR_SED_002-001 Atch 02. The copy provided to SED is not dated and is Version 0. The same document, also Version 0, dated October 9, 2013, was submitted to the Commission on October 29, 2013 within the document titled “PG&E Pipeline Safety Enhancement Plan (PSEP) Update Prepared Testimony,” Application 13-10(U 39 G), filename: PSEP_Update_Test_PGE_20131029_289314 (from PG&E web site)

⁴² GasPipelineSafetyOIR_DR_SED_002-001 and pelineSafetyOIR_DR_SED_002-001 atch 01

⁴³ GasPipelineSafetyOIR_DR_SED_002-001

⁴⁴ GasPipelineSafetyOIR_DR_SED_002-001Atch02, p. 9, Section 3.3

⁴⁵ Ibid, p. 18, Table 2, where determination of unknown long seam type is based on purchase date,

⁴⁶ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch466

1 pipe has the same joint efficiency (.8) as A.O. Smith pipe. Thus, the incorrect assumption of a
2 1947 purchase date would nevertheless result in the correct joint efficiency number in this
3 instance.⁴⁷ PG&E attributes the erroneous assumption of DSAW and a resulting Joint efficiency
4 of 1.0 to an incorrect decision made by a PG&E engineer.⁴⁸ So, it happens that in this instance, if
5 the PG&E instruction had been followed, the pipe type would have been misidentified, but the
6 critical data, i.e. the joint efficiency factor, would have been correct.

7 While PG&E represents that it is fixing this problem in the PRUPF process by
8 automating it, it cannot deny that the entire PFL database was populated with assumptions prior
9 to discovering this problem.⁴⁹

10 Recommendation: For Line 147, PG&E must revisit each assumption made before it
11 discovered the PRUPF problem, in order to determine if it should be modified to a more
12 conservative value. The same task lies ahead for PG&E on the broader scale for all pipelines in
13 high consequence areas.

14 **C. Risk 3 – A pressure test alone is not an adequate basis for an MAOP.**

15 PG&E argues that even though the data for Line 147 does not support the MAOP of 365
16 psig, which is the MAOP the Commission restored the line to in 2011, operation of the pipe to
17 that pressure was safe because the pipe had withstood a pressure test that supports an MAOP of
18 365 psig.⁵⁰ However, it is more likely that PG&E was simply lucky that the pipe did not fail
19 before the weakest links of A.O. Smith and SSAW pipe were discovered and the MAOP was
20 reduced to 330 psig. As it turned out, by running a pressure test before it knew of the A.O. Smith
21 pipe, PG&E exceeded the SMYS of the pipe, potentially damaging the pipe and activating
22 previously stable cracks, creating an ongoing safety risk.

23 According to PG&E, in November 2012, just after the leak on Line 147 was discovered,
24 “[t]he PSEP team was asked to re-evaluate this line using their logic tree to see if this pipe would
25 be replaced or prioritized differently.” Specifically, in emails between PG&E managers,

26 “. . . this segment would not need to be replaced in phase 1, work to be
27 done by 2014. According to the PSEP Decision Tree, this segment would

⁴⁷ *ibid*

⁴⁸ Verified Statement of Kirk Johnson, August 30, 2013, para.35

⁴⁹ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475

⁵⁰ Verified Statement of Kirk Johnson, August 30, 2013 para 5, para 22, and Verified Statement of Sumeet Singh, Oct 18, 2013, para 12.2, quoting Keifner & Associates

1 have an action of "Retrofit and conduct an ILI at next re-assessment"
2 (C7). This is because the pipe already has a valid strength test record, is
3 HCA and is operating over 30% of SMYS. Unless adjacent segments
4 need to be replaced or tested, then this segment would not be addressed
5 as part of PSEP."⁵¹

6 Despite the implied suggestion in PG&E's statement that any pressure test can be used to support
7 a desired MAOP, such a position is contrary to PG&E's own standards and explanations of the
8 risks of over pressuring a line.

9 PG&E's standard for piping design and test requirements is A-34. The most recent
10 version of A-34 is Revision 4, dated March 29, 2013.⁵² The instructions for performing a
11 pressure test for MAOP include the following statements:

12 **“(3) Maximum Test Pressure at Minimum Elevation**

13 Determine this value by referring to the **Maximum Test Pressure** row of
14 Table A-1 in Numbered Document A-34, Attachment A, "Test
15 Requirements." Read all associated notes and, if necessary, adjust to
16 create a practical test range. Ensure that the pressure range is sufficient to
17 permit variations in the test pressure due to elevation, temperature changes
18 during the test, or equipment problems/limitations.

19
20 "Where an elevation difference exists, the maximum test pressure occurs
21 at the lowest elevation point in the test section. The **control point** is most
22 often at the minimum elevation. If there are sections of pipe with different
23 specifications or strengths or other limiting components, then the control
24 point might be at a higher elevation. Explain this exception in the
25 **Components limiting test pressure/Control Point exceptions** field in
26 Part 1 of the STPR.

27
28 "CAUTION: The test pressure for any pipeline must not be greater than
29 the pressure which produces a hoop stress of 100% of SMYS of the pipe,
30 regardless of the strength of the valves, regulators, and similar equipment.

31 If the MAOP of the pipeline cannot be established without exceeding the
32 rated pressure of the equipment, consult Pipeline Engineering."⁵³
33 (Underline added.)
34

⁵¹ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475_CONF, Sec. 3.0. *Note:* ILI means In Line Inspection.

⁵² GasPipelineSafetyOIR_DR_DRA_087-Q02Atch01, *Note:* It does not appear that the sections quoted were changed in any significant ways from the previous versions of A-34.

⁵³ *Ibid*, P. 34

1 In a data response, PG&E elaborated on the risks of exceeding the SMYS of a
2 pipe during a pressure test:

3 a. If the test pressure causes the hoop stress on the pipe to exceed 100% of
4 the specified minimum yield strength (SMYS) of the steel, then the steel
5 can weaken and experience structural damage. If the test pressure exceeds
6 the mill test pressure, small, otherwise stable manufacturing defects in the
7 pipe could cause the pipe to fail. . .

8 b. It is preferable to have accurate records whenever possible. However,
9 industry experience demonstrates that operators will sometimes lack
10 complete historical records for older pipe. In such instances, as the
11 Commission has recognized, it is appropriate to use engineering-based
12 conservative assumptions for pipeline components where complete
13 records are not available.

14 c. Hydrotesting a line without accurately calculating hoop stress could
15 pose a safety risk if the pipe were to significantly yield during the test but
16 not rupture, leaving a potential weak point in the pipe. PG&E's testing
17 procedures have safeguards that minimize the safety risk in this situation.
18 First, we make significant efforts to understand the pipe characteristics
19 prior to testing. This includes conducting physical inspections of the pipe
20 with unknown characteristics before testing if possible. Where there are
21 still unknown characteristics, PG&E's test procedure for in-situ pipe
22 monitors for pipe yielding by maintaining a Pressure versus Volume plot
23 of each test. Pipe yielding would be the indication that the pipe was
24 different than expected and the test pressure was too high for that segment
25 of pipe (as explained in the response to part (a)). Pipe yielding is
26 monitored by recording the pressure increase versus the pump strokes and
27 corresponding volume of water added to the test section to produce the
28 pressure during the pressure test. The theoretical slope within the elastic
29 range for the pipeline is produced and the actual pressure and volume are
30 plotted throughout the pressurization of the segment. If the pressure vs
31 volume plot begins to deviate from the elastic slope, it is an indication that
32 there is excessive air trapped within the test section being compressed, the
33 elastic limit of some pipe within the section has been reached, or a leak
34 has occurred.⁵⁴

35 The relevant concern for Line 147 is that because PG&E was not aware of the older,
36 reused pipe in the line, it tested the pipe to a pressure level that "probably" exceeded 100 % of

⁵⁴ GasPipelineSafetyOIR_DR_DRA_086-Q22

1 the pipe's SMYS. This was an unsafe pressure level based on PG&E's own guidance.⁵⁵ PG&E
2 has stated:

3 "Given the 0.8 joint efficiency of the AO Smith pipe and the hydro test
4 pressure. The hydrostatic test probably took the line 0 - 10 psi over the
5 100% SMYS level." (Underline added)⁵⁶

6 In fact, the 2011 pressure test (also referenced in Part II above) indicates pipe yielding in
7 the Pressure v. Volume plot for the test T-43B (Mile Point 1.95 to 3.40).⁵⁷ PG&E's certifying
8 engineer, who does not appear to have been on site during the pressure test, discounted the test
9 results by noting that excess air was introduced into the pipeline.⁵⁸ However, there is no real
10 evidence other than the note on the certification statement that air was introduced into the
11 pipeline.

12 PG&E clearly understands that a hydrotest at too high a pressure can cause a pipe to fail.
13 PG&E's expert metallurgist, Robert Caligiuri, testified in the San Bruno case I.12-01-007
14 regarding the failure of L-132, that the root cause of the failure was a hydrotest performed when
15 the pipe was installed and that, over time, a pre-existing defect that survived the pressure test
16 ultimately failed catastrophically.⁵⁹ As PG&E stated in that proceeding:

17 "Dr. Caligiuri also analyzed the possible source of the ductile tear, without
18 which fatigue crack growth to rupture would not have been possible.
19 Based on burst pressure and metallurgical stress analyses, as well as the
20 absence of any other plausible cause, Dr. Caligiuri concluded the ductile
21 tear in the longitudinal seam on pup 1 was likely caused by a post-
22 installation pressure test.⁶⁰ Dr. Caligiuri's metallurgical examination
23 revealed that the initiation of the ductile tear preceded the fatigue crack
24 growth. Dr. Caligiuri further determined that the magnitude of the single
25 loading event required to cause the ductile tear was greater than the
26 operational pressure fluctuations Segment 180 likely experienced over its

⁵⁵ See above, and GasPipelineSafetyOIR_DR_DRA_086-Q22Atch078

⁵⁶ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch499

⁵⁷ GasPipelineSafetyOIR_DR_DRA_086-Q02Atch04_CONF, p. 25-26

⁵⁸ GasPipelineSafetyOIR_DR_DRA_086-Q02Atch04_CONF, Note under "Remarks" on page 18 (Note, too, that the remarks also include a statement that the water truck ran out of water during the spike pressure test. Given that the engineers should accurately calculate how much water is required for a hydrotest, and given that loss of water is often associated with leakage, this finding suggests a test that might not have been well managed or overseen, calling the results into question.)

⁵⁹ I.12-01-007 PG&E Opening Brief, March 11, 2013, p. 14

⁶⁰ Ex. PG&E-1 at 3-5 to 3-17 (PG&E/Caligiuri)

1 lifetime.⁶¹ Using mathematical models to calculate the pipe's burst
2 pressure, Dr. Caligiuri concluded that a post-installation hydro test was the
3 likely cause of the ductile tear in pup 1.”^{62 63}
4

5 PG&E's Consulting Engineer was obviously concerned that the 2011 hydrotest might have
6 caused the leak in Line 147 when he wrote in an email:

7 “[c]ould the recent hydro test [have] contributed to additional cracking in
8 this pipe and essentially activated a threat? Are we sitting on a San Bruno
9 situation? With fatigue crack growth over many years? Is the pipe cracked
10 and near failure? I don't want to panic people but seems like we should
11 consider this and probably move this pipe up the PSEP priority for
12 replacement.”⁶⁴

13 In an internal report, the Consulting Engineer also stated:

14 “[T]he appearance of a leak a year after this pipe was hydro tested, with
15 external corrosion that was previously repaired, and knowledge that the
16 pipe was originally manufactured in 1929 all indicate that we could have
17 more extensive problems on this section of pipe. There is potential that the
18 hydro test has “activated” cracks within a potentially weakened and older
19 pipe.”⁶⁵

20 And,

21 “[t]he change in pipe specifications requires a re-evaluation of the 2011
22 hydro test to determine if the pipe was over-stressed by the hydro test. The
23 difference in elevation from the lowest elevation to the location of the AO
24 Smith pipe is approximately 104 ft or approximate 45 psi. The maximum
25 test pressure at the minimum elevation was 748 psi. The AO Smith pipe
26 would have been subjected to a test pressure of 703 psi. Using what we
27 currently believe to be the correct pipe properties 100% SMYS occurs at
28 700 psi.”⁶⁶
29

⁶¹ Ex. PG&E-1 at 3-9 (PG&E/Caligiuri). As Dr. Caligiuri further explained: “Fatigue cracking is characterized by stable crack growth that occurs incrementally over time in response to cyclic loading. Characteristic features called fatigue striations, indicative of fatigue growth under operational pressure fluctuations, were present at greater depths than the ductile tear.” *Id*

⁶² Ex. PG&E-1 at 3-11 to 3-12 (PG&E/Caligiuri).

⁶³ I.12-01-007 PG&E Opening Brief, March 11, 2013, p. 15

⁶⁴ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch443

⁶⁵ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475

⁶⁶ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475, Sec 3.3.7

1 Further, PG&E’s experts, Keifner & Associates, advise the industry that defects surviving
2 pressure tests may ultimately result in pipeline failure from fatigue, stating

3 “If a pipeline is hydrostatically tested to a given pressure, defects of a
4 certain size that are present at the time of the test will fail. Smaller defects
5 would be expected to survive the test but would not be expected to grow
6 further at a static pressure level much below the test pressure level.
7 However, if a defect as large as size ‘a’ remains after a hydrostatic test and
8 if the pipeline is subjected to sufficient pressure fluctuations, the defect
9 will fail after time ‘t.’”⁶⁷

10 Keifner goes on to explain how the data from a test scenario was used to calculate ‘time
11 to failure’ based on the number and frequency of pressure fluctuations.⁶⁸ The risk with Line 147
12 is not associated only with current operations. It is also necessary to consider the past, largely
13 unknown operating history of some of the older, vintage pipe in the pipeline, and also the
14 possibility that PG&E might alter operations on this line in the future (increasing pressure and
15 cyclic pressure frequency) long after this proceeding has concluded. Safe operation of Line 147,
16 in its current configuration, requires operating the line at a low and relatively constant pressure.⁶⁹

17 Recommendation: Accurate data or the most conservative assumptions must be applied in
18 order to conduct hydrotesting safely. It is recommended that PG&E follow its own internal
19 procedures and guidance on pressure testing, as shown in this section.

⁶⁷ “When does a pipeline need revalidation? The influence of defect growth rates and inspection criteria on an operator’s maintenance program,” Keifner, John F., and Vieth, Patrick H., Keifner and Associates, Inc., published in Pipeline Rules of Thumb Handbook, E.W. McAllister, Editor, p. 690, 2009

⁶⁸ Ibid, p. 691-692

⁶⁹ GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475, Sections 1.2 , 2.2, 3.2

ATTACHMENT

Margaret Felts

Serves as the lead technical consultant to law firms, regulatory agencies and private entities on environmental, energy and corporate fraud cases, concentrating her practice on behind-the-scene discovery, research and strategy development. She also serves as Expert Witness.

Positions external to consulting include serving as Deputy Director of the California Department of Toxic Substances Control (DTSC), where she managed the State's Superfund program, including the base closure program for the oversight of toxic cleanup of military bases closed by the federal government. Prior to working for the state, Felts served as Division Chief of Environmental Engineering at for the Department of Defense at McClellan AFB. In this position she was responsible for developing a program to bring the base into compliance with Federal, State and local environmental regulations. Felts came to California from Texas when she was recruited by the California Energy Commission to fill a lead technical position in the Fuels Office.

SPECIALTIES

Discovery and technical strategies for complex cases Involving:

- Pipeline Integrity Management records and processes
- Gas and Electric Utilities regulatory cases
- Oil & Gas industry cases
- Groundwater contamination
- Hazardous waste disposal and site cleanup
- Historical records research

EMPLOYMENT HISTORY

LITIGATION CONSULTANT 1983 - PRESENT
M.C. Felts Co. (see attached page)

PRESIDENT / CFO 2002 - 2010
California Communications Association

SENIOR CONSULTANT 1995-1997
Dames & Moore

DEPUTY DIRECTOR 1993-1995
California Department of Toxic Substances Control

DIVISION CHIEF OF ENGINEERING 1985-1990
Department of Defense, McClellan Air Force Base

ENVIRONMENTAL CONTRACTOR
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Margaret Felts

LITIGATION EXPERIENCE AS LEAD TECHNICAL CONSULTANT AND EXPERT

2013-Present

APPLICATION NO. 1608617, PROCEEDING ID No. 1995 ATCO
PIPELINES – URBAN PIPELINE REPLACEMENT PROJECT

2011-Present

ORDER INSTITUTING INVESTIGATION (OII) ON THE COMMISSION'S
OWN MOTION INTO THE OPERATIONS AND PRACTICES OF PACIFIC
GAS AND ELECTRIC COMPANY WITH RESPECT TO FACILITIES RECORDS
FOR ITS NATURAL GAS TRANSMISSION SYSTEM PIPELINES.
CONSUMER PROTECTION & SAFETY DIVISION

2005-2007

LODI GROUND WATER CONTAMINATION CLIENT: LAW FIRMS
REPRESENTING LLOYDS OF LONDON INSURANCE COMPANIES
INSURANCE DEFENSE

2000-2002

CALIFORNIA ENERGY CRISES ENRON INVESTIGATION PG&E
BANKRUPTCY CLIENT: CA PUBLIC UTILITIES COMMISSION ENERGY,
PLAINTIFF

PLAYA DEL REY GAS STORAGE INTEGRITY, SoCAL EDISON CLIENT: CA
PUBLIC UTILITIES COMMISSION, DIVISION OF RATE PAYER
ADVOCATES ENERGY, PLAINTIFF

2001-2002

BELMONT PROPERTIES CLIENT: ROPERS ENVIRONMENTAL, DEFENSE
THREE SISTERS RANCH CLIENTS: DUANE MORIS & TED HANIG LAW
FIRMS ENVIRONMENTAL, DEFENSE

AEROJET & LOCKHEED CASES CLIENTS: MORRIS POLICH & PURLLY,
BERKES, CRANE, ROBINSON & SEAL LLP INSURANCE DEFENSE

PG&E POWER OUTAGE, SAN FRANCISCO DIVISION OF RATE PAYER
ADVOCATES ENERGY, PLAINTIFF

1998-2000

RAYTHEON GROUND WATER CONTAMINATION LAW FIRMS
REPRESENTING LLOYDS OF LONDON INSURANCE COMPANIES
INSURANCE DEFENSE

1998-1999

PG&E TREE TRIMMING CASE

MONTEBELLO GAS STORAGE (SoCAL GAS) CLIENT: CA PUBLIC
UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES ENERGY,
PLAINTIFF

1997 -2002

SKINNER V. ARCO CLIENTS: TERRY LUMSDEN LAW FIRM KELLER
ROHRBACK L.L.P., ENERGY/ENVIRONMENTAL, PLAINTIFF

1996-1997

SoCAL GAS V. ASSOCIATED ELECTRIC GAS INSURANCE COS. CLIENT:
HANCOCK, ROTHERT & BUNSHOFT, LA INSURANCE DEFENSE

1997 -1998

EXXON V. INA, SUPERFUND CLEANUP CLAIMS CLIENT: HANCOCK,
ROTHERT & BUNSHOFT, SF INSURANCE DEFENSE

1996-2000

PROCTOR V. LOCKHEED SOIL AND GROUNDWATER CONTAMINATION

CLIENTS: LAW FIRMS REPRESENTING LLOYDS OF LONDON INSURANCE
COMPANIES, PLAINTIFF

1993

TOOLEY OIL V. SNIDER CLIENT: NAGLEY & MEREDITH, INC.
ENVIRONMENTAL, PLAINTIFF

CLAYTON RD. ASSO INC. V. TEXACO REFINING & MARKETING INC.

CLIENT: NED ROBINSON ENVIRONMENTAL, PLAINTIFF

WALSH V. DIABLO MARINE CLIENT: TURNER, HUGUET, BRANS &
ADAMS ENVIRONMENTAL, PLAINTIFF

TASSAJARA NURSERY V. INSURANCE CO. CLIENT: NELSON,
WARNLOF & VENCILL INSURANCE, DEFENSE

1992

WISE/WILLIAMS V. BECHTEL CLIENT: POTTER LAW OFFICES TORT
CASE FOR INJURIES RESULTING FROM MOHAVE POWER PLANT
INCIDENT ENERGY, PLAINTIFF

PACHECO PROPERTIES V. CHEVRON PIPELINE CLIENT: TURNER,
HUGUET, BRANS & ADAMS ENVIRONMENTAL, PLAINTIFF

NEVADA POWER V. STATE OF NEVADA CLIENT: STATE OF NV
ATTORNEY GENERAL OFFICE OF ADVOCATE CUSTOMERS OF THE
PUBLIC UTILITIES COMMISSION ENERGY, PLAINTIFF

1991-1993

PG&E APPLICATION RE HELMS PUMPED STORAGE CLAIM CLIENT:
CA PUBLIC UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF

1991

SALLE V. RUDD, ET AL CLIENT: KLAUSCHIE & SHANNON, INSURANCE
DEFENSE

1990

AEROJET GENERAL CORP, ET AL V. ARGONAUT INSURANCE CO., ET
AL CLIENT: HANCOCK, ROTHERT & BUNSHOFT, INSURANCE DEFENSE

1988 -1992

SCE APPLICATION RE MOHAVE COAL FIRED PLANT STEAM PIPE
FAILURE CLIENT: CA PUBLIC UTILITIES COMMISSION, DIV. OF
RATEPAYER ADVOCATES, ENERGY, PLAINTIFF

1987-1988

SoCAL GAS APPLICATION -CONTRACT BUYOUT RE MONTEREY LAND
PARK LANDFILL GAS (OPERATING INDUSTRIES) CLIENT: CA PUBLIC
UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES, ENERGY /
ENVIRONMENTAL, PLAINTIFF

1986

SoCAL GAS V. FORD, BACON & DAVIS CLIENT: LAW FIRM
REPRESENTING FORD, BACON & DAVIS, ENERGY, PLAINTIFF

1985

US OF A BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION
RE PACIFIC OFFSHORE PIPELINE COMPANY, DOCKET NO. RP85-34-
000 CLIENT: CA PUBLIC UTILITIES COMMISSION, ENERGY,
PLAINTIFF

1983 -1985

SoCAL GAS, APP NO. 84-09-022 RE PACIFIC OFFSHORE PIPELINE
COMPANY (POPCO) GAS TREATMENT PLANT CLIENT: CPUC, DIV.
OF RATEPAYER ADVOCATES, ENERGY, PLAINTIFF