**BASS BERRY + SIMS PLC**

R. DALE GRIMES

TEL: (615) 742-6244
FAX: (615) 742-2744
dgrimes@bassberry.com

A PROFESSIONAL LIMITED LIABILITY COMPANY
ATTORNEYS AT LAW

150 THIRD AVENUE SOUTH, SUITE 2800
NASHVILLE, TN 37201
(615) 742-6200

www.bassberry.com

OTHER OFFICES:

KNOXVILLE
MEMPHIS
WASHINGTON, D.C.

February 2, 2017

***Via Hand-Delivery***

The Honorable Earl Taylor
Executive Director
Tennessee Regulatory Authority
c/o Sharla Dillon
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

***Re:*** ***Petition of Piedmont Natural Gas Company, Inc. for Approval of an Integrity Management Rider to Its Approved Rate Schedules and Service Regulations***
**Docket No. 16-00140**

Dear Mr. Taylor:

I enclose an original and five (5) copies of the public version of Piedmont Natural Gas Company, Inc.'s ("Piedmont") supplemental response to Item 14 of the Consumer Protection and Advocate Division's informal discovery requests of January 13, 2017 in the above docket. This response was provided to the Consumer Advocate on February 1, 2017.

This material is also being filed by way of email to the Tennessee Regulatory Authority Docket Manager, Sharla Dillon. Filed along with this material are four copies of the Confidential material responsive to the Data Request, submitted under seal, containing Confidential Response 1-14, Attachment 1 of 2, in a separate envelope.

Please file the original and four copies of the public version of this filing and stamp the additional copy as "filed". Then please return the stamped copy to me by way of our courier.

Should you have any questions concerning this matter, please do not hesitate to contact me at the email address or telephone number listed above.

With kindest regards, I remain

Very truly yours,

R.D. Grimes

R. Dale Grimes

**PIEDMONT NATURAL GAS COMPANY, INC.**
**INTEGRITY MANAGEMENT RIDER**
**TRA DOCKET NOS. 16-00140**
**CAPD INFORMAL DATA REQUEST NO. 1**
**Date Issued: January 13, 2017**

14. Please provide a description of the OASIS project and a description of the OASIS project's function as it relates to the IMR Rider. Discuss in detail with specificity all of the components of the OASIS project. Further, provide the Company's rationale as to why the OASIS project is included in the IMR Rider and, in addition, provide copies of any work papers, spreadsheets, summaries, charts, notes, exhibits, articles, journals, treatises, periodicals, publications, reports, records, statements, Internet web pages, studies, or financial information that provides a cost / benefit or potential realizable benefit from OASIS.

**Supplemental Response:** Please see CONFIDENTIAL 1-14 Supplemental Attachment 1 of 2 containing Piedmont's Business Case for the OASIS project as well as OASIS project presentations shown to the Company's Strategic Advisory Board ("SAB").

The over-riding mandate of PHMSA's TIMP and DIMP requirements is for natural gas pipeline and distribution operators to know, maintain, and operate their systems in a manner designed to maximize public safety. These requirements are a direct response to several significant incidents that have occurred in the industry and a general recognition that much of the documentation and record-keeping associated with existing transmission and distribution systems is maintained in hard-copy form and, in many cases, is incomplete. In order to comply with the PHMSA requirements, many companies (including Piedmont) are updating their systems for recording and documenting the information relevant to underground pipeline and distribution facilities. The OASIS system is specifically designed to provide a single platform resource for the management of information relevant to the location, condition, maximum operating pressures, and physical properties of Piedmont's system. OASIS is capable of sorting such information and producing a comprehensive description of all parts of Piedmont's operating system in a short amount of time without the need to locate and parse extensive physical records that might, in some cases, be decades old, if they exist at all. Like all technological advances, the design and construction of the OASIS system is expensive but it provides a consolidated system management tool that is necessary to comply with PHMSA's TIMP/DIMP requirements. The primary benefit of OASIS is increased safety and reliability of Piedmont's transmission and distribution systems and the avoidance of incidents (like that of San Bruno) where the LDC's lack of readily available knowledge of its system contributes to a catastrophic failure of that system. Secondary benefits include increased efficiency in accessing records and, once the system is up and fully operational, cost savings in accomplishing required system reviews and maintenance. Please see 1-14 Supplemental Attachment 2 of 2 highlighting the violations of Pacific Gas and Electric Company for the San Bruno system failure.

Supplemental Response prepared by: PNG Regulatory Affairs & Reporting (Kally Couzens) and Operations (Victor Gaglio)

Response provided by Piedmont Natural Gas on February 1, 2017.

# CAPD Informal DR 1-14
# Supplemental Attachment 1 of 2

# Filed Under Seal

MELINDA HAAG (CABN 132612)
United States Attorney

FILED
APR - 1 2014
RICHARD W. WIEKING
CLERK, U.S. DISTRICT COURT
NORTHERN DISTRICT OF CALIFORNIA

UNITED STATES DISTRICT COURT

NORTHERN DISTRICT OF CALIFORNIA

SAN FRANCISCO DIVISION

TEH

| | |
|---|---|
| UNITED STATES OF AMERICA, | No. CR 14 175 |
| Plaintiff, | VIOLATIONS: Failure to Gather and Integrate Relevant Data to Identify All Potential Threats To a Gas Transmission Pipeline (49 U.S.C. § 60123 and 49 C.F.R. § 192.917(b)); Failure to Maintain Certain Repair Records for a Gas Transmission Pipeline (49 U.S.C. § 60123 and 49 C.F.R. § 192.709(a)); Failure to Identify and Evaluate Potential Threats to a Gas Transmission Pipeline (49 U.S.C. § 60123 and 49 C.F.R. § 192.917(a)); Failure to Include All Potential Threats and to Select a Suitable Threat Assessment Method for a Gas Transmission Pipeline (49 U.S.C. § 60123 and 49 C.F.R. § 192.919); Failure to Prioritize a Gas Transmission Pipeline With an Unstable Manufacturing Threat (49 U.S.C. § 60123 and 49 C.F.R. § 192.917(e)(3)); and Failure to Prioritize and Assess a Gas Transmission Pipeline With an Unstable Manufacturing Threat (49 U.S.C. § 60123 and 49 C.F.R. § 192.917(e)(4)) |
| v. | |
| PACIFIC GAS AND ELECTRIC COMPANY, | |
| Defendant. | |

# INDICTMENT

The Grand Jury charges:

At all times relevant to this Indictment unless otherwise indicated:

## INTRODUCTORY ALLEGATIONS

1. PACIFIC GAS AND ELECTRIC COMPANY ("PG&E") was a California corporation headquartered in San Francisco, California, that provided natural gas and electric services to approximately 15 million customers in Northern and Central California.

2. PG&E was a pipeline operator that provided natural gas to customers through the use of over 6,000 miles of natural gas transmission pipelines and over 40,000 miles of distribution pipelines. Gas transmission pipelines are highly-pressurized, large-diameter lines that carry natural gas to smaller, less pressurized distribution pipelines that bring natural gas into homes, commercial buildings, and other facilities.

3. Line 132 was a high-pressure gas transmission pipeline owned and operated by PG&E in the Northern District of California. Line 132 ran underground from Milpitas, California, to San Francisco, California, passing through the City of San Bruno, California.

4. Line 132 was originally installed in or about and between 1944 and 1948 and consisted of hundreds of individual segments, the majority of which were in suburban or urban areas.

5. On September 9, 2010, at approximately 6:11 p.m., a portion of Line 132 (Segment 180) ruptured in a residential neighborhood of the City of San Bruno (the "San Bruno explosion"). Gas escaping from the rupture ignited, causing a fire that killed eight people and injured 58 others. The fire also damaged 108 homes, 38 of which were completely destroyed.

## The Natural Gas Pipeline Safety Act of 1968

6. The Natural Gas Pipeline Safety Act of 1968 ("PSA") established minimum safety standards for pipeline transportation and for pipeline facilities. The purpose of the PSA was to protect against risks to life or property posed by pipeline transportation and pipeline facilities by improving the regulatory and enforcement authority of the Secretary of Transportation.

7. In 1970, pursuant to Chapter 601 of the PSA, the Secretary of Transportation issued regulations codified in Section 192 of Title 49 of the Code of Federal Regulations, Subparts A through M ("Section 192").

8. In 1979, Congress amended the PSA to add criminal penalties for knowing and willful violations of any regulation or order issued pursuant to Chapter 601 of the PSA. 49 U.S.C. § 60123.

The Gas Transmission Integrity Management Rule and Relevant Regulations

9. Congress amended the PSA by enacting the Pipeline Safety Improvement Act of 2002 ("PSIA"). The Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued the Gas Transmission Integrity Management regulations ("IM regulations"), 49 C.F.R. Part 192, referred to as Subpart O, to implement the requirements of the PSIA. The IM regulations specified how pipeline operators were required to identify, prioritize, assess, evaluate, remediate, and validate the integrity of segments of gas transmission pipelines that could, in the event of leak or failure, affect high-consequence areas ("HCAs"). 49 C.F.R. §§ 192.901-192.949. An HCA is a locale where a release of gas could pose a significant risk of injury or death.

10. The IM regulations required pipeline operators to identify threats on segments of their gas transmission pipelines that operated in HCAs (hereinafter "covered segments"), rank the risk levels of these identified threats, select an assessment method or technology with a proven application capable of assessing the known or potential threats, create deadlines for both the initial and future assessments of these covered segments, and address the threats identified and evaluated through mitigation, remediation, and prevention. 49 C.F.R. §§ 192.907 and 192.921.

Regulations Regarding the Identification of Potential Threats

11. Under the IM regulations, pipeline operators had to identify and evaluate all potential threats to a covered segment. 49 C.F.R. § 192.917(a). The nine major threats to gas transmission pipelines were: third party damage, external corrosion, internal corrosion, stress corrosion cracking, manufacturing threats, construction threats, equipment threats, external factors such as weather and earthquakes, and incorrect operation. 49 C.F.R. § 192.7 (incorporating by reference American Society of Mechanical Engineers ("ASME") B31.8S, 2004).

12. To identify and evaluate all potential threats to each covered segment, pipeline operators

were required to gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. 49 C.F.R. § 192.917(b). Section 192.917(b) required pipeline operators to follow a specific industry standard - ASME B31.8S, section 4 - and, at a minimum, gather and evaluate data for each covered segment and any similar, non-covered segments found in the entire pipeline system, including, but not limited to:

- Past incident history and the root cause analysis of previous threats on the segment, including leak and failure history.
- Records regarding past and ongoing corrosion of the segment.
- Continuous surveillance records regarding any changes along the segment including failures, leaks, and earth movement as well as changes along the segment that might affect its class location.
- Patrolling records regarding third party damage and encroachment threats to the segment.
- Maintenance history including repairs on the segment (pursuant to Section 192.709(a) of Title 49 of the Code of Federal Regulations, each pipeline operator was required to maintain the date, location, and description of each repair made to pipe so long as the pipeline remained in service).
- Records of internal inspections for issues such as internal corrosion, seam welding faults or repairs, and the existence of liquids being trapped or transported in the segment.
- The thickness of the walls of the segment.
- The diameter of the segment.
- The type of seams used along the segment and the corresponding "joint factor" that was used to calculate the initial pressure-carrying capacity of the pipe.
- The manufacturer and date of manufacture of the segment.
- The "depth of cover" or the amount of clearance between the top of the segment and the surface of the ground.
- Construction techniques, including bending or joining methods.
- Material properties, such as specified minimum yield strength ("SMYS").
- The results of any pressure tests conducted on the pipeline containing the segment (pursuant to Section 192.517 of Title 49 of the Code of Federal Regulations, each pipeline operator was required to retain for the useful life of a pipeline a record of each strength pressure test performed under Section 192.505 of Title 49 of the Code of Federal Regulations for each segment of a steel pipeline that was to operate at a hoop stress of 30 percent or more of the SMYS).

- Any pressure fluctuations or records of "cyclic fatigue" or the weakening of a pipeline due to pressure fluctuations on the pipeline containing the segment.
- Normal maximum and minimum operating pressures for the segment.
- Any audits or reviews that identified issues for the segment or made recommendations for mitigation or prevention of those issues.

Baseline Assessment Plan and Assessment Method Regulations

13. The IM regulations required pipeline operators to prepare, no later than December 17, 2004, a Baseline Assessment Plan ("BAP") that identified all of the pipeline operator's covered segments, the known or potential threats to each covered segment, the methods selected to assess the integrity of the pipeline for each covered segment, and deadlines for conducting an initial assessment and re-assessment. 49 C.F.R. § 192.919.

14. Once the known and potential threats were identified on a covered segment, the IM regulations required pipeline operators to assess the integrity of the pipeline in each covered segment by using an assessment method that was capable of addressing the specific identified threats. 49 C.F.R. § 192.921(a). The four assessment methods available to assess whether a covered segment was susceptible to the identified threats were:

(1) Subpart J pressure testing: a method of testing the strength of a pipeline by pressurizing a portion of the pipeline to a specified test pressure and monitoring that portion of the pipeline for leaks or ruptures. The test had to comply with the requirements of Subpart J of Section 192. When the test was performed with a liquid, this method was also known as a "hydrotest" or a "Subpart J hydrotest." 49 C.F.R. § 192.921(a)(2).

i. Starting in 1970, all new gas transmission pipelines had to be pressure tested or hydrotested before being placed into service in order to ensure the pipeline's integrity. Pursuant to Section 192.619 of Title 49 of the Code of Federal Regulations, gas transmission pipelines installed before 1970 that were found to be in "satisfactory condition" were grandfathered in and did not have to be pressure tested or hydrotested unless otherwise required by law.

ii. A pressure test or hydrotest was the only assessment method that could test the strength of a pipeline. Performing a pressure test or hydrotest on a gas transmission pipeline necessitated the expense and inconvenience of taking the pipeline out of service temporarily.

iii. Pressure testing or hydrotesting assessed the integrity of a pipeline for such potential threats as external damage, external corrosion, internal corrosion, stress corrosion cracking, and manufacturing and construction threats, such as seam defects and seam corrosion.

(2) In-line inspection ("ILI"): a method of examining the internal characteristics of a pipeline by sending a computerized inspection tool, often called a "pig," through the inside of the pipeline. 49 C.F.R. § 192.921(a)(1).

i. Like pressure testing or hydrotesting, ILI assessed the integrity of the pipeline for such potential threats as external damage, external corrosion, internal corrosion, stress corrosion cracking, and manufacturing and construction threats. ILI, however, could not test the actual strength of a pipeline.

(3) Direct assessment ("DA"): a process used to detect the presence of corrosion and assess the potential threat to the integrity of the pipeline. 49 C.F.R. § 192.921(a)(3). The three methods of DA were:

i. External corrosion direct assessment or "ECDA," which tested the outside of pipelines for external corrosion and third party damage using an electrical or magnetic technology above ground and then following up with interspersed excavations to uncover the portions of the pipelines most likely to have external corrosion. Because ECDA only assessed the outside of pipelines, it could not assess the integrity of pipelines for potential internal threats such as manufacturing or construction defects;

ii. Internal corrosion direct assessment ("ICDA"), which tested for corrosion inside the pipeline; and

iii. Stress crack corrosion direct assessment ("SCCDA"), which was only applicable to pipelines operating over 60% of SMYS and thus not applicable in most HCAs.

(4) New Technology: any technology that a pipeline operator demonstrated could provide an understanding of a pipe's condition that was equivalent to the understanding that could be gained using pressure tests or hydrotests, ILI, or DA. Operators could only use a new technology if PHMSA approved its use. 49 C.F.R. § 192.921(a)(4).

//

Regulations Related to the Prioritization of Manufacturing Threats

15. The IM regulations required operators to prioritize the risk level of covered segments in the BAP. 49 C.F.R. § 192.917(e)(3)(i)-(iii). Operators were required to prioritize covered segments with unstable manufacturing threats as "high risk." Covered segments with manufacturing threats were considered unstable if the operating pressure of the pipeline containing that segment increased above the maximum operating pressure experienced by that segment in the five years before the segment was identified as being in an HCA (the "5-year MOP"), the maximum allowable operating pressure ("MAOP") increased, or the stresses leading to cyclic fatigue increased. 49 C.F.R. § 192.917(e)(3)(i)-(iii).

16. For pipelines with unstable manufacturing threats, operators had to use an assessment method that was capable of evaluating manufacturing threats, such as a hydrotest. 49 C.F.R. § 192.917(e)(3) and (4). ECDA could not be used because ECDA does not assess manufacturing threats. 49 C.F.R. § 192.923(a).

17. Pipeline operators also had to prioritize as high risk and select an assessment method capable of assessing seam integrity and seam corrosion anomalies for covered pipeline segments that contained:

a) low-frequency electric resistance welded ("ERW") pipe;

b) lap welded pipe; or

c) other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appxs. A4.3 & A4.4;

and had experienced either:

d) a seam failure; or

e) an increase in operating pressure over the 5-year MOP.

49 C.F.R. § 192.917(e)(4).

Regulations Related to Continuous Evaluation of Covered Pipeline Segments

18. Pipeline operators were required to periodically evaluate the integrity of each covered segment. The periodic evaluation included considering and integrating past and present integrity assessment results, integrating data and assessing risk of the entire pipeline, and reviewing decisions

regarding remediation, additional prevention, and mitigation actions. Operators were required to use the results from these periodic evaluations to identify the threats specific to each covered segment and the risk represented by these threats. 49 C.F.R. § 192.937.

19. After an initial assessment, pipeline operators had to re-assess their lines using an assessment method capable of assessing a particular threat or combination of threats including new threats, and within a certain time period depending on the results the periodic evaluations, but not to exceed seven years. 49 C.F.R. §§ 192.937 and 192.939.

## PG&E's Practices Relating to Gas Transmission Pipelines

### A. General Recordkeeping

20. Starting at a time unknown to the grand jury, and continuing until the San Bruno explosion, PG&E learned that it did not have complete data for its gas transmission pipelines due to missing records and errors and omissions in existing records.

21. PG&E received notice of recordkeeping problems through employees, through regulatory agencies including the National Transportation Safety Board and the California Public Utilities Commission, and from third party auditors and consultants.

22. Despite knowledge of these deficiencies, PG&E did not create a recordkeeping system for gas operations that would ensure that pipeline records were accessible, traceable, verifiable, accurate, and complete. PG&E's recordkeeping deficiencies included:

- PG&E did not maintain accurate and complete leak records for its gas transmission pipelines.
- PG&E did not maintain accurate and complete records regarding encroachment of population along gas transmission pipelines.
- PG&E did not maintain repair records for its gas transmission pipelines in a traceable and accessible manner.
- PG&E did not retain or maintain weld maps and weld inspection records for its gas transmission pipelines.
- PG&E did not maintain complete records of the manufacturer of its gas transmission pipelines in service.

- PG&E did not retain or maintain Subpart J pressure test records for the life of all of its gas transmission pipelines.

- PG&E did not maintain accurate, complete, or accessible "job files," that contained, among other things, pipe specifications, construction records, pressure test records, and purchasing records.

B. Integrity Management Program

23. In the late 1990s, in advance of the enactment of the IM regulations, PG&E created a computer database, called the Geographic Information System (the "GIS database"). PG&E intended that the GIS database would contain information about each natural gas transmission pipeline segment, such as pipe specifications and pressure test data, and would be used to make integrity management decisions.

24. To create the GIS database, PG&E relied on pipeline survey sheets that contained erroneous and incomplete information. In creating the GIS database, PG&E undertook no quality control or quality assurance to ensure the data taken from the pipeline survey sheets was accurate. From GIS's inception, PG&E was aware that the database contained erroneous and incomplete information.

25. PG&E relied on information in the GIS database to make integrity management decisions, including the identification of threats to each covered segment contained in the initial BAP.

C. Threat Identification

26. In identifying and evaluating threats as required by Sections 192.917(a) and (b), PG&E failed to gather and integrate all relevant data for many of its older transmission lines, including, but not limited to:

- past incident history for both covered and non-covered segments, including leaks with unknown causes ("unknown" because PG&E either had no records, or could not or did not locate such records);

- pipeline history for covered and non-covered segments that were greater than one mile away from the covered segments being analyzed for manufacturing and construction threats;
- maintenance history, including repairs;

- accurate and complete pipeline data, including wall thickness, diameter, seam type, manufacturer, and date of manufacture;
- pressure fluctuations;

- validated normal, maximum, and minimum operating pressures;

- threats created by cyclic fatigue; and
- threats created by internal corrosion.

D. Assessment Method Selection

27. PG&E relied on inaccurate and incomplete records to select assessment methods to assess the integrity of covered segments for known or potential threats as required by Section 192.921(a).

28. In 2004, PG&E created a written policy on compliance with the IM regulations regarding data gathering that instructed PG&E employees to rely on available, verifiable information or "information that c[ould] be obtained in a timely manner."

29. In 2004, PG&E also created a written policy that proscribed, with certain limited exceptions, the use of hydrotesting or pressure testing as an assessment method for assessing the integrity of covered segments. Pursuant to this policy, the only two options (other than a PHMSA-approved new technology) for assessing threats on covered segments were ILI and ECDA. PG&E instituted this policy having determined that, due to economic considerations and the physical attributes of its transmission lines, ILI was not a feasible assessment method for approximately 80% of its transmission lines that were subject to the IM regulations.

30. For the approximately 80% of the gas transmission pipelines where PG&E determined that ILI was not economically or physically feasible, PG&E selected ECDA to assess threats on those pipelines. PG&E chose ILI as an assessment method for the approximately 20% of its remaining natural gas transmission pipelines.

E. Assessment Avoidance on Older Transmission Lines

i. Planned Pressure Increases

31. When the IM regulations went into effect, PG&E knew that thousands of miles of its gas transmission pipelines had never been subjected to a Subpart J pressure test, because the pipelines were installed before 1970 and were grandfathered in or because PG&E had not maintained a record of such a pressure test. As PG&E knew, many of these pipelines had a known or potential manufacturing threat due to their age, manufacturer, and/or history.

32. In order to maintain the then-current operating pressures of these pipelines without having to subject the pipelines to a Subpart J pressure test, PG&E adopted a practice in 2003 called

"planned pressure increases" ("PPIs"). To conduct a PPI, PG&E intentionally raised the pressure in several old highly-pressurized gas transmission pipelines located in HCAs to the pipelines' maximum allowable operating pressures (MAOP) for two hours. In so doing, PG&E at times exceeded the lines' 5-year MOPs and/or MAOPs. PG&E failed to review the history of the pipelines or verify the accuracy of its data prior to executing the PPIs to determine whether intentionally increasing the pressure on these older pipelines would affect the integrity of the pipeline. PG&E periodically conducted PPIs from 2003 until the San Bruno explosion.

33. PG&E executed PPIs on a number of its high pressure gas transmission pipelines, including lines 132, 101, and 109, all of which had covered segments with manufacturing threats that had never been subject to a Subpart J pressure test or for which records of such a test were not available. From 2002 until the San Bruno explosion, PG&E assessed these pipelines with ECDA.

ii. Unplanned Pressure Increases

34. PG&E was aware that hundreds of covered segments totaling over 80 miles of gas transmission pipelines had never been subject to a Subpart J pressure test and had manufacturing threats that could be considered unstable due to unplanned pressure increases that exceeded the pipelines' respective 5-year MOPs. These covered segments were found on numerous gas transmission pipelines operated by PG&E, including, but not limited to, segments on Lines 132, 153, and DFM 1816-01.

35. Section 192.917(e) required PG&E to prioritize the covered segments with unstable manufacturing threats as high risk and assess them using an assessment method that evaluated the integrity of the covered segment to determine the risk of failure from the unstable manufacturing threats, such as a Subpart J pressure test. For all of these covered segments, despite knowledge of the requirements of Section 192.917(e), PG&E chose not to reprioritize these pipelines as high risk and/or properly assess the integrity of each segment to determine the risk of failure. Instead, PG&E continued to choose ECDA to assess the integrity of these pipelines even though PG&E knew ECDA did not assess unstable manufacturing threats.

36. To avoid having to prioritize these pipelines as "high risk" and properly assess the pipelines for the known threats, PG&E chose only to consider a manufacturing threat unstable if the pressure on the pipeline exceeded the 5-year MOP by 10% or more. PG&E adopted and implemented

this approach despite knowing since 2004 that PHMSA had issued regulations and additional guidance on those regulations that stated any increase in pressure that went above the 5-year MOP, regardless of amount, destabilized a manufacturing threat and required PG&E to prioritize the pipeline as high risk and to properly assess the pipeline. PG&E maintained this practice until 2011.

F. Line 132

37. When identifying threats on Line 132, and when determining the appropriate assessment technology to use in evaluating those threats, PG&E did not know the thickness of the pipeline walls for approximately 42% of Line 132, either because PG&E did not have records describing wall thickness or it could not or did not access records with this information.

38. PG&E did not know the manufacturer for approximately 80% of the hundreds of segments on Line 132 either because PG&E did not have such records, or could not or did not access such records with this information.

39. PG&E did not know the depth of cover for approximately 80% of Line 132 because PG&E did not have such records, or could not or did not access such records with this information.

40. PG&E used improper yield strength or SMYS values for several segments of pipe on Line 132 with unknown yield strengths.

i. Segment 180

41. Segment 180, the portion of Line 132 that ruptured, was located in an HCA and ran through a densely populated suburban development in the City of San Bruno. Segment 180 consisted of six short lengths or "pups" of 30-inch diameter pipe along with normal lengths of pipe. The date of manufacture of these pups is unknown, but the manufacture date was prior to 1956. The pups were welded together and installed in approximately 1956 in a manner that violated industry standards concerning fabrication of gas transmission pipelines in effect at the time. One or more of the pups had a defective seam weld. The segment, in part due to the defective pup or pups, had a yield strength significantly less than the yield strength that PG&E recorded and relied upon for integrity management purposes.

42. PG&E's records reflected the following for Segment 180:

- The pipe was seamless.

- The SMYS was 42,000 psi.
- The depth of cover was unknown.
- The manufacturer of the pipe was unknown.
- The manufacture date of the pipe was 1956.
- A pressure test had been performed in 1961.
- The MAOP was 400 psi.

43. In fact, the pipe in Segment 180 was seamed, not seamless. The SMYS was unknown, but measured after the San Bruno explosion at significantly less than 42,000 psi for four of the six pups. The pipe manufacturer date was unknown, but occurred well before 1956. No records of a pressure test existed showing that any pressure test, let alone a Subpart J pressure test, had been performed on Segment 180. Other records in PG&E's files also showed the MAOP for Line 132 as 375 and 390 psi.

44. At no time between installation of the defective pup or pups and the San Bruno explosion did PG&E check or confirm whether its records accurately reflected the data relevant to assessing the integrity of Segment 180, even though PG&E knew that GIS contained incomplete and inaccurate data.

ii. Integrity Management For Line 132

45. PG&E identified segments of Line 132 as being in an HCA in 2002 and began conducting ECDA on Line 132 in 2002. PG&E also conducted ECDA on Line 132 in 2003, 2004, 2006, 2007, 2009, and 2010.

46. In identifying the threats that existed on Line 132 and choosing an assessment method to assess those identified threats, PG&E knowingly relied on erroneous and incomplete information from the GIS database and failed to gather and integrate, among other things, the following data and information:

- Leak data, including the cause of over 30 prior leaks on segments of Line 132; instead PG&E adopted a practice that it would not consider leaks with "unknown" causes when deciding if ECDA was a proper assessment method;
- Industry and PG&E data that showed that double submerged arc weld "DSAW" pipe manufactured by Western Consolidated Steel, which was found on segments of Line 132, including Segment 181, had pipe body and longitudinal seam defect issues;
- A seam weld defect in DSAW pipe that was discovered on a different segment of Line 132, and was similar to pipe on both Segment 180 and Segment 181, and was repaired in

1988;

- Multiple longitudinal seam cracks found during radiography of girth welds on portions of Line 132 that were constructed in 1948;

- A longitudinal seam weld defect in DSAW pipe discovered on a different segment of Line 132 in 1992 when a tie-in girth weld was radiographed;

- A defective weld found on Segment 186 of Line 132 in 2009. The segment was originally fabricated by Consolidated Western using pipe similar to Segment 180 and Segment 181 and installed in 1948, at or near the time when Segment 180 was originally installed;

- A field girth weld defect found on Segment 189 in 2009. Segment 189 was also originally fabricated by Consolidated Western using DSAW pipe installed in 1948;

- Whether any salvaged or re-used pipe, for which PG&E did not keep records, including manufacturer, dates of use, and history of the pipe, had been used on Line 132;

- Documents related to the design, manufacturer, construction, or testing of Segment 180 when it was relocated in 1956, including whether any salvaged pipe was used;

- Information from the 1956 construction file related to the six pups installed on Segment 180 by PG&E;

- The potential impact of cyclic fatigue or other loading conditions on Line 132 from planned or unplanned pressure fluctuations; and

- Additional construction defects on Line 132.

47. PG&E also knowingly failed to gather and integrate the following relevant data from similar gas transmission pipeline segments as required by 49 C.F.R. § 192.917(b):

- A seam leak in DSAW pipe found on Line 300B in 1958;
- A characterization evaluation of nearby Line 109 girth welds in 1994;
- A Subpart J pressure test failure in 1974 of a seam weld with lack of penetration on DSAW pipe found on Line 300B, and which was similar to DSAW pipe found on Segment 180 and Segment 181;
- Laboratory test reports from 1975 relating to Line 101 girth welds; and,
- Cracking of a seam weld in DSAW pipe in 1996 on Line 109 which paralleled Line 132.

48. Relying on inaccurate and incomplete information regarding the pipeline attributes and history of Line 132, PG&E knowingly chose ECDA as the assessment method to assess the integrity of covered segments on Line 132, including Segment 180, starting in 2002 and continuing until the San Bruno explosion.

49. In 2003 and again in 2008, as part of PG&E's PPIs, PG&E intentionally raised for a two-hour period the pressure of Line 132 at least 25 psi above the normal operating pressure the pipeline had experienced for decades in order to maintain a current MOP for Line 132 without having to conduct a Subpart J pressure test. PG&E undertook this practice without conducting any review of the pipeline's history, including past leaks and the cause of such leaks, or verification of the pipeline's specifications in order to assess whether intentionally increasing the pressure on Line 132 more than 25 pounds higher than the line had experienced in decades would affect the integrity of the pipeline.

50. On July 23, 2009, Line 132, at a point north of Segment 180, experienced an unplanned pressure increase that exceeded that segment's 5-year MOP. That segment of Line 132 had a known manufacturing threat that was destabilized when the pipeline experienced this pressure increase. Despite knowledge of this pressure excursion and the requirement to properly assess unstable manufacturing threats, PG&E chose to assess that segment of Line 132 in 2009 using ECDA even though PG&E knew that ECDA could not assess unstable manufacturing threats.

THE CHARGES

COUNT ONE: (49 U.S.C. § 60123 – Natural Gas Pipeline Safety Act) [Line 132]

51. The allegations set forth in paragraphs 1-12, 20-26, and 37-50 above are re-alleged and incorporated herein by reference.

52. Starting in or about December 2003, and continuing through on or about September 9, 2010, in the Northern District of California, the defendant,

PACIFIC GAS AND ELECTRIC COMPANY,

by and through the actions of its employees, knowingly and willfully violated a minimum safety standard for pipelines carrying natural gas, as set forth in Title 49, Code of Federal Regulations, Section 192.917(b). Specifically, PACIFIC GAS AND ELECTRIC COMPANY, knowingly and willfully failed to gather and integrate existing data and information on a line, specifically Line

132, that could be relevant to identifying and evaluating all potential threats on covered segments of that line, all in violation of Title 49, United States Code, Section 60123.

COUNT TWO: (49 U.S.C. § 60123 -- Natural Gas Pipeline Safety Act)

53. The allegations set forth in paragraphs 1-12, 20-26, and 37-47 above are re-alleged and incorporated herein by reference.

54. Starting on a date unknown to the grand jury and continuing until at least on or about September 9, 2010, in the Northern District of California, the defendant,

PACIFIC GAS AND ELECTRIC COMPANY,

by and through the actions of its employees, knowingly and willfully violated a minimum safety standard for pipelines carrying natural gas, as set forth in Title 49, Code of Federal Regulations, Section 192.709(a). Specifically, PACIFIC GAS AND ELECTRIC COMPANY, knowingly and willfully failed to maintain records concerning the date, location, and description of each repair made to a line, specifically Line 132, all in violation of Title 49, United States Code, Section 60123.

COUNTS THREE THROUGH FIVE: (49 U.S.C. § 60123 – Natural Gas Pipeline Safety Act)

55. The allegations set forth in paragraphs 1-12, 18, 19-26, and 37-50 above are re-alleged and incorporated herein by reference.

56. Starting on a date unknown to the grand jury and continuing through on or about the dates set forth in the table below, in the Northern District of California, the defendant,

PACIFIC GAS AND ELECTRIC COMPANY,

by and through the actions of its employees, knowingly and willfully violated a minimum safety standard for pipelines carrying natural gas, as set forth in Title 49, Code of Federal Regulations, Section 192.917(a). Specifically, PACIFIC GAS AND ELECTRIC COMPANY, knowingly and willfully failed to identify and evaluate potential threats to covered segments on the lines set forth below:

//

//

| Count | Date | Line |
|---|---|---|
| 3 | January 22, 2010 | Line 132 |
| 4 | January 22, 2010 | Line 153 |
| 5 | January 22, 2010 | DFM 1816-01 |

All in violation of Title 49, United States Code, Section 60123.

COUNTS SIX THROUGH EIGHT: (49 U.S.C. § 60123 -- Natural Gas Pipeline Safety Act)

57. The allegations set forth in paragraphs 1-50 above are re-alleged and incorporated herein by reference.

58. Starting on a date unknown to the grand jury and continuing through on or about the dates set forth in the table below, in the Northern District of California, the defendant,

PACIFIC GAS AND ELECTRIC COMPANY,

by and through the actions of its employees, knowingly and willfully violated a minimum safety standard for pipelines carrying natural gas, as set forth in Title 49, Code of Federal Regulations, Section 192.919. Specifically, PACIFIC GAS AND ELECTRIC COMPANY, knowingly and willfully failed to include in its annual baseline assessment plan all potential threats on a covered segment and failed to select the most suitable assessment method to assess all potential threats on covered segments on the lines set forth below:

| Count | Date | Line |
|---|---|---|
| 6 | January 22, 2010 | Line 132 |
| 7 | January 22, 2010 | Line 153 |
| 8 | January 22, 2010 | DFM 1816-01 |

All in violation of Title 49, United States Code, Section 60123.

//

//

//

//

COUNTS NINE THROUGH ELEVEN: (49 U.S.C. § 60123 -- Natural Gas Pipeline Safety Act)

59. The allegations set forth in paragraphs 1-10, 13-19, 27-40, and 49-56 above are re-alleged and incorporated herein by reference.

60. Starting on a date unknown to the grand jury and continuing through on or about the dates set forth in the table below, in the Northern District of California, the defendant,

PACIFIC GAS AND ELECTRIC COMPANY,

by and through the actions of its employees, knowingly and willfully violated a minimum safety standard for pipelines carrying natural gas, as set forth in Title 49, Code of Federal Regulations, Section 192.917(e)(3). Specifically, PACIFIC GAS AND ELECTRIC COMPANY, knowingly and willfully failed to prioritize covered segments of lines as high risk segments for the baseline assessment or a subsequent reassessment, after a changed circumstance rendered manufacturing threats on segments of the lines set forth below unstable:

| **Count** | **Date** | **Line** |
|---|---|---|
| 9 | January 22, 2010 | Line 132 |
| 10 | January 22, 2010 | Line 153 |
| 11 | January 22, 2010 | DFM 1816-01 |

All in violation of Title 49, United States Code, Section 60123.

COUNT TWELVE: (49 U.S.C. § 60123 -- Natural Gas Pipeline Safety Act)

61. The allegations set forth in paragraphs 1-10, 13-19, 27-40, and 49-56 above are re-alleged and incorporated herein by reference.

62. Starting on a date unknown to the grand jury, and continuing through January 22, 2010, in the Northern District of California, the defendant,

PACIFIC GAS AND ELECTRIC COMPANY,

by and through the actions of its employees, knowingly and willfully violated a minimum safety standard for pipelines carrying natural gas, as set forth in Title 49, Code of Federal Regulations, Section 192.917(e)(4). Specifically, PACIFIC GAS AND ELECTRIC COMPANY, knowingly and willfully failed to prioritize covered segments of a line, specifically DFM 1816-01, as high risk segments for a baseline assessment or a subsequent reassessment after a changed circumstance rendered manufacturing threats on those segments unstable, and failed to analyze covered segments to determine the risk of failure from such manufacturing threats, all in violation of Title 49, United States Code, Section 60123.

DATED: ____/____, 2014

Foreperson

MELINDA HAAG
United States Attorney

J. Douglas Wilson

J. DOUGLAS WILSON
Chief, Criminal Division

(Approved as to form: ________
AUSA GEIS
AUSA BERGER
SAUSA HALBERSTADT
SAUSA MORRIS

Business

# PG&E slapped with record $1.6 billion penalty for fatal San Bruno explosion

By **GEORGE AVALOS** | gavalos@bayareanewsgroup.com |
PUBLISHED: April 9, 2015 at 4:12 am | UPDATED: August 12, 2016 at 3:39 am

SAN FRANCISCO — State regulators slapped PG&E with a record-setting $1.6 billion penalty Thursday for causing the fatal gas-pipeline explosion in San Bruno more than four years ago, after a hearing marked by emotional statements from victims of the blast and sharp words about continued flaws in the utility's safety record.

"PG&E is safer. But I just don't believe PG&E is safe enough," Michael Picker, president of the state Public Utilities Commission, told this newspaper in an interview after the PUC voted 4-0 to levy the penalty. Citing numerous lapses involving PG&E's sprawling natural gas pipeline system since the 2010 San Bruno explosion, Picker said he was ordering the PUC to conduct a wide-ranging probe into PG&E's safety culture.

Thursday's hearing and the contentious process that led up to it brought almost as much scrutiny and criticism of the PUC as it did of PG&E. Federal regulators sharply criticized how the PUC monitored the utility before the blast, and thousands of emails released after the explosion painted a picture of a regulatory agency disturbingly close to a utility that it was supposed to oversee.

Those disclosures unleashed criticism of Michael Peevey, who stepped down at the end of 2014 as PUC president and was replaced by Picker.

Thursday's decision appears to auger a new environment for the PUC and PG&E.

"Let this decision and our vote herald a new era of safety," Commissioner Catherine Sandoval said.

The agency will be under close scrutiny as it attempts to respond to the criticism of its past actions. "Customers are looking to the PUC to rein in PG&E and be a watchdog, rather than a lap dog," said Mark Toney, executive director of The Utility Reform Network, a consumer group often critical of both.

The $1.6 billion fine — which exceeds the $1.45 billion the utility reported in profit in 2014 — is not the last of PG&E's legal and regulatory troubles. It has already been hit with multiple fines and penalties, still must confront a 28-count criminal indictment on federal charges and is under investigation by state prosecutors who are probing the email controversy. Search warrants served by the state attorney general at the residences of Peevey and former PG&E regulatory executive Brian Cherry show that criminal investigators were seeking evidence of improper communications, judge shopping, bribery and obstruction of justice involving the utility and the state agency.

Investigators believe that a combination of PG&E's flawed record keeping and shoddy maintenance, coupled with the PUC's lax oversight, were the key factors that caused the explosion that killed eight and wrecked a quiet San Bruno neighborhood.

The $1.6 billion penalty is the largest ever against a utility in the United States. The largest previous penalty was a $101 million punishment against El Paso Natural Gas for a fatal explosion in New Mexico in 2000.

Picker questioned whether PG&E is too big to provide safe utility services.

"Is the organization simply too large, being spread across a sizable portion of a large state, and encompassing diverse functions such as gas transmission and gas distribution, as well as electric service, to succeed at safety?" Picker said.

Picker pointed to safety breaches at the Metcalf electricity substation in South San Jose and gas system incidents in Kern County, Carmel, Morgan Hill, Castro Valley, Cupertino and Milpitas — all of which occurred since the September 2010 explosion — as examples of PG&E's ongoing safety flaws.

Yet the PUC also stumbled in its oversight of PG&E, Picker acknowledged.

"We failed," Picker said. "PG&E violated its public trust. But we weren't vigilant enough."

The new ruling requires that PG&E shareholders pay $850 million for gas system safety improvements, that the company refund $400 million to gas customers, and that PG&E pay a $300 million fine to the state.

"Since the 2010 explosion of our natural gas transmission pipeline in San Bruno, we have worked hard to do the right thing for the victims, their families and the community of San Bruno," PG&E spokesman Keith Stephens said. PG&E said it won't appeal the PUC penalty.

San Francisco-based PG&E has already spent or committed to spend $2.8 billion on shareholder-funded safety improvements to its pipeline system, replaced more than 800 miles of cast-iron pipes of the type that failed in San Bruno with modern pipes, and installed more than 200 gas valves that can operate automatically or be controlled remotely. The utility also has opened a state-of-the-art control center in San Ramon that is the nerve center of PG&E's gas system.

Before voting, the PUC took the unprecedented step of allowing survivors of the disaster to address the panel.

Sue Bullis told the PUC that three members of her family were killed in the explosion, including her son Will. She recounted that she dropped off her son at school that day, told him she loved him and said she would see him that night.

"It's as if a game of Russian roulette was being played. My family was on the wrong end of that game," Bullis told the PUC. "I blame PG&E for the deaths of my family. I blame the CPUC, which was supposed to be the watchdog agency. I'm going to remember this my whole life."

Contact George Avalos at 408-859-5167. Follow him at Twitter.com/georgeavalos.

Tags: Technology

**George Avalos** George Avalos is a business reporter for the Bay Area News Group.

Follow George Avalos @georgeavalos

## CERTIFICATE OF SERVICE

The undersigned hereby certifies that on February 2, 2017, a copy of the attached was served on the following by electronic mail and by depositing a copy of the same in the United States Mail, First Class Postage Prepaid, addressed as follows:

Wayne Irvin
Emily Knight
Office of the Attorney General
Consumer Advocate and Protection Division
P. O. Box 20207
Nashville TN 37202

R. D. [illegible]

______________________________