Stipulations of Fact

San Bruno OII – I.12-01-007, Recordkeeping OII – I.11-02-016,
and Class Location OII – I.11-11-009

(Note: Some facts in this list may be changed and new facts may be listed in the future because discovery in I.11-02-016 remains open and PG&E is in the process of responding to recent data requests.)

Pacific Gas and Electric Company (PG&E) stipulates that the following facts are true and accurate:

I. Introduction

1. (CPSD Report, p.7) On September 9, 2010, at approximately 6:11pm, a 30-inch diameter natural gas transmission pipeline owned and operated by PG&E ruptured in San Bruno, California.
2. (p.7) Gas escaping from the ruptured pipeline ignited resulting in the loss of eight lives, injuries to 58 people, destruction of 38 homes, moderate to severe damage to 17 homes, and minor damage to 53 homes.
3. (p.8) Energy released from the rupture created a crater about 72 feet long by 26 feet wide. A 28-foot long section of pipe weighing approximately 3,000 pounds was ejected from the crater and landed approximately 100 feet from the crater in the middle of Glenview Drive.
4. (NTSB report page 125, paragraph 21) The deficiencies identified during the NTSB and CPSD investigations are indicative of an organizational accident. (SB)
5. (NTSB report page 125, paragraph 22) The multiple and recurring deficiencies in PG&E operational practices indicate a systemic problem. (SB)
6. (NTSB report, page 126; paragraph 25) Because PG&E has not incorporated the use of effective and meaningful metrics as part of their performance-based pipeline safety management programs, PG&E was unable to effectively evaluate or assess the integrity of its pipeline system. (SB)

7. (NTSB report, page 127) The probable cause of the accident was PG&E's (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase stemming from poorly planned electrical work at the Milpitas Terminal; and (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section. (SB)

II. Events on the Day of the Incident

8. (p.7) At 2:46pm on September 9, 2010, clearance procedures to replace an Uninterruptable Power Supply (UPS) were initiated at PG&E's Milpitas Terminal. The Milpitas Terminal receives natural gas from southern California, Texas and the Rocky Mountain Area and distributes it into 8 pipelines (Line 100, 101, 109, 132 and 0805-01).

9. (p.73) The Milpitas Terminal has four incoming lines and five outgoing lines and is equipped with pressure regulation and overpressure protective devices to control incoming and outgoing pressure. The pressure regulating valves are electrically actuated with Supervisory Control and Data Acquisition (SCADA) system controls while the monitor valves are pneumatically controlled valves.

10. (p.7-13) At 4:18pm during the installation of the UPS, power was lost to the SCADA system, resulting in loss of data for pressures, flows, and valve positions, for the pipelines at the Milpitas Terminal.

11. (p.8) Loss of information and control over the pipelines caused various regulating valves to fully open. This caused gas pressure in lines leaving the Milpitas Terminal, including Lines 101, 109 and 132, to increase. According to telemetry data obtained during the investigation, the pressure on Line 132 leaving the Milpitas Terminal reached 396 psig as measured manually.

12. (p.8) The highest pressure recorded at an upstream location closest to Segment 180 just prior to the failure was determined to be 386 psig. Based on a review of

historical pressure data, this was the highest pressure Segment 180 had experienced within the seven years preceding the rupture.

13. (p.11) At 5:22pm, the SCADA center alarm console displayed over 60 alarms within a few seconds, including controller error alarms and high differential pressure and backflow alarms from the Milpitas Terminal. These alarms were followed by pressure alarms on several lines leaving the Milpitas Terminal, including Line 132.

14. (p.11) At 6:11pm, SCADA data indicated that a rupture had occurred when pressures on Line 132 upstream of Martin station rapidly decreased from a high of 386 psig.

III. Response to the Rupture

15. (p.11) At 6:12pm the first police unit arrived at the scene. At 6:13pm the first San Bruno Fire Department unit arrived at the scene.

16. (p.11) At 6:18pm an off-duty PG&E employee notified the PG&E dispatch center in Concord, California, of an explosion in the San Bruno area. Over the next few minutes, the dispatch center received additional similar reports.

17. (p.11) At 6:23pm PG&E dispatch sent a Gas Service Representative (GSR) working in Daly City (about 8 miles from San Bruno) to confirm the report. About the same time, PG&E's Senior Distribution Specialist who saw the incident fire while driving home from work, reported the fire to the PG&E dispatch center and proceeded to the incident scene.

18. (p.118) No outgoing calls were made by PG&E to fire or police officials upon discovery of the incident.

19. (p.12) At 6:35pm a PG&E Measurement and Control (M&C) Mechanic saw media reports about the fire and proceeded to the PG&E Colma yard.

20. (p.12) At 7:06pm, the Mechanic recognized the rupture as occurring in Line 132 and called the Peninsula Division Transmission and Regulation (T&R) Supervisor to tell him he was going to isolate the rupture. The Supervisor authorized the

action. Two PG&E Mechanics left the Colma yard, driving toward the first mainline valve (at MP 38.49) that they planned to close. They were joined en route by San Francisco (SF) Division T&R Supervisor.

21. (p.12) At 7:20pm, the two PG&E Mechanics and the SF Division T&R Supervisor arrived at the first Segment 180 valve location. At 7:29pm the Mechanics began manually closing the valves near the incident location. At 7:46pm the Mechanics completed closing all the valves which isolated the ruptured portion.

22. (p.13) By early morning on September 10, firefighters declared 75% of all active fires to be contained. By the end of the day on September 11, 2010, fire operations continued to extinguish fires and monitor the incident area for hot spots and then transferred incident command to the San Bruno Police Department.

23. (p.13) During the 50 hours following the incident, about 600 firefighting (including emergency medical service) personnel and 325 law enforcement personnel responded. Fire crews and police officers conducted evacuations and door-to-door searches of houses throughout the response. In total, about 300 homes were evacuated. Firefighting efforts included air and forestry operations. Firefighters, police officers, and members of mutual aid organizations also formed logistics, planning, communications, finance, and damage assessment groups to orchestrate response efforts and assess residential damage in the accident area.

24. (NTSB report page 125, paragraph 13) Use of automatic shutoff valves or remote control valves along the entire length of Line 132 would have significantly reduced the amount of time taken to stop the flow of gas and to isolate the rupture. (SB)

25. (NTSB report, page 127) Contributing to the severity of the accident were the lack of either automatic shutoff valves or remote control valves on the line and PG&E's flawed emergency response procedures and delay in isolating the rupture to stop the flow of gas. (SB)

26. (NTSB report, page x) PG&E took 95 minutes to stop the flow of gas and to isolate the rupture site—a response time that was excessively long and contributed to the extent and severity of property damage and increased the life-threatening risks to the residents and emergency responders. (SB)

IV. Description of Segment 180

27. (p.7) The section of pipeline involved in the incident was Segment 180, at Mile Post (MP) 39.28 of PG&E's Line 132, located at the intersection of Earl Avenue and Glenview Drive in San Bruno, California.

28. (CPSD reply testimony, p.6; NTSB report, p.133) The City of San Bruno is in a Class 3 location, and Segment 180 was intended to meet the design and construction requirements in effect at that time for a Class 3 location. Class 3 refers to any location unit that has 46 or more buildings intended for human occupancy.

29. (p.23) PG&E provided a pressure log from the Milpitas Terminal dated October 16, 1968, showing a recorded pressure of 400 psig for Line 132. This pressure log was used by PG&E as the basis for establishing a maximum allowable operating pressure (MAOP) of 400 psig for Line 132.

30. (p.7; p.47) PG&E incorrectly identified the entire length of Segment 180 as a seamless 30-inch diameter pipe.

31. (p.15) Segment 180 was installed in 1956 as part of a relocation project of approximately 1,851 feet of Line 132 that had been originally constructed in 1948. The relocation of Segment 180 started north of Claremont Drive and extended south of San Bruno Avenue and moved the pipeline from the east side to the west side of Glenview Drive.

32. (p.15) This relocation was necessary because of grading associated with land development in the vicinity of the existing pipeline. The construction was performed by PG&E personnel.

33. (p.16) Segment 180 was originally documented in PG&E records as being 30-inch diameter seamless steel pipe with a 0.375 inch wall thickness and having a Specified Minimum Yield Strength (SMYS) of 52,000 psi, installed in 1956. PG&E obtained this material specification information for Segment 180 from accounting records rather than engineering records.

34. (CPSD reply testimony, p.21; NTSB Report, p.28.) PG&E stated its belief that the pipe was most likely produced by Consolidated Western in 1948, 1949 or 1953.

35. (CPSD reply testimony, p.21) According to PG&E, between 1947 and 1957, it purchased a total of 320,065 feet of 30-inch pipe from three suppliers. NTSB investigators examined the records and determined that the pipe used for the 1956 project was assembled from multiple material procurement orders.

36. (p.16) The NTSB discovered after the incident that there were six short lengths of pipe known as "pups" in the area of the rupture. The rupture originated in Pup 1. PG&E records for Segment 180 did not disclose the existence of the pups. The manufacturer of the pups is unknown.

37. (p.19) An NTSB metallurgical examination determined that the yield strength values of all six of the pups were lower than 52,000 psi, which was the PG&E-designated yield strength for Segment 180.

38. (p.20) Pup 1, the failed pup on which the fracture initiated, was found to have yield strength of only 36,600 psi, and Pup 2 had the lowest yield strength of 32,000 psi.

39. (p.20) Longitudinally, Pups 1, 2 and 3, were partially welded on the seam from the outside and the weld did not penetrate through the inside of the pipe. No inside weld, required for a DSAW welded pipe, was found on the inside of the pipe. According to the NTSB metallurgical examination, the fusion welding process left an unwelded region along the entire length of each seam, resulting in a reduced wall thickness.

40. (p.21; NTSB Metallurgy report p.6) The pups' girth welds and longitudinal seams contained welding deficiencies related to incomplete fusion, burnthrough, slag inclusion, crack, undercut, excess reinforcement, porosity defects and lack of penetration.

41. (p.22) All of the pups used for Segment 180 were less than 5 feet in length.

42. (p.22; p.48) PG&E was unable to produce and/or locate records demonstrating that a strength test was performed on Segment 180 at the conclusion of its construction or at any time during its operation.

43. (p.60-61; NTSB report, p.49) The NTSB report found that the calculated burst pressure estimates were 594 and 515 psig for Pup 1; 668 and 574 psig for Pup 2; and 558 and 430 psig for Pup 3, respectively. The analysis was done assuming no crack growth in the weld defect in Pup 1 and no angular misalignment of the Pup 1 longitudinal seam. Based on the pipeline characteristics associated with the pups and the Class 3 location, if a strength test had been performed to 1.4 times MAOP (400 x 1.4 = 560 psig) it is highly probable that the pups in Segment 180 would have failed.

V. Integrity Management

44. (p.134) In 2004, PHMSA established the Gas Transmission Integrity Management Rule (49 CFR Part 192, Subpart O), commonly referred to as the "Gas IM Rule." The Gas IM Rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect high-consequence areas within the United States.

45. (p.25) The requirements (49 CFR Part 192) in high consequence areas (HCAs) were effective with the signing into law of the 2002 Pipeline Safety and Improvement Act on December 17, 2002. This required PHMSA to promulgate regulations no later than one year after enactment. PHMSA noticed the new regulations on December 15, 2003, and these regulations required that by

December 17, 2004, operators were to have IM plans developed and to have identified all HCAs.

46. (p.25) The IM regulations included requirements for threat analysis, risk ranking, assessment methods and re-assessment timetables.

47. (NTSB report page 125, paragraph 19) PG&E's gas transmission integrity management program was deficient and ineffective. (SB)

48. (p.26) PG&E did not gather all relevant leak data on Line 132 and integrate it into its Geographic Information System (GIS).

49. To comply with the federal safety regulations, PG&E needed a methodology to integrate data so that it could evaluate the potential risks to the pipelines. The method chosen should have allowed PG&E to gather and integrate existing data and information on the entire pipeline that could be relevant to covered segments. (CCSF Testimony I.12-01-007 at p. 11-12)

50. PG&E is required to verify that the necessary pipeline data have been assembled and integrated. At a minimum, PG&E should have evaluated and gathered for each segment information on the operation, maintenance, patrolling, design, operating history, and specific failures and concerns unique to each system and segment. (CCSF Testimony I.12-01-007 at p. 12)

51. Basic elements of proper data integration and evaluation include: storage, retrieval, granularity, collection, aggregation, and integration. (CCSF Testimony I.12-01-007 at p. 12)

52. Data integration consists of more than simply putting several types of information into a single location. "The most important aspect of data integration is the analysis of aggregated data in order to discern integrity threats and risks that would not otherwise be observed from independently reviewing the various individual data elements." (CCSF Testimony I.12-01-007 at p. 12)

53. PG&E did not have a consistent, repeatable basis for gathering and integrating accurate data. (CCSF Testimony I.12-01-007 at p. 13)

54. PG&E's RMP-01 did not contain any requirement to verify the accuracy of the data used. (2011 Risk Assessment Audit).

55. PG&E did not adequately perform the data integration analysis required by the Gas IM Rule. (CCSF Testimony I.12-01-007 at p. 13)

56. (p.26) PG&E did not always use conservative default values for pipeline segments in Line 132.

57. (p. 26) PG&E did not check the material specifications of pipeline segments in Line 132 for accuracy.

58. (p.32; NTSB Report p.61) The NTSB Report documents a number of examples where data from PG&E's GIS were in error, but not discovered by PG&E, including:

    a. the pipe wall thickness was an assumed value for 21.5 miles (41.75 percent) of Line 132;

    b. the manufacturer of the pipe was unknown ("NA") for 40.6 miles (78.81 percent) of Line 132;

    c. the pipeline depth of ground cover was also unknown for 42.7 miles (82.79 percent) of Line 132;

    d. three values were used for the SMYS of grade B pipe: 35,000 psi, 40,000 psi, and 45,000 psi;

    e. two segments with unknown SMYS were assigned values of 33,000 psi and 52,000 psi, not 24,000 psi;

    f. six consecutive segments, totaling 3,649 feet, specified an erroneous minimum depth of cover of 40 feet;

    g. several segments, including Segment 180, specified 30-inch-diameter seamless pipe, although there was no API-qualified domestic manufacturer of such pipe when the line was constructed; and

    h. the GIS did not reflect the presence of the six pups in Segment 180.

59. (p.26; NTSB Report, p.109) PG&E did not consider known longitudinal seam cracks dating to the 1948 construction and at least one other leak, which occurred in 1988, on a long seam of the 1948 portion of pipe. Closed leak information, such as the October 27, 1988, leak, which had been repaired, was not transferred to the GIS.

60. (p.33-35; NTSB report p.39) The NTSB Report documents a number of defects that were not incorporated into PG&E's analysis of the condition of the pipe for its 2004 Baseline Assessment Plan (BAP).

    a. 1948, Line 132: Multiple longitudinal seam cracks found during radiography of girth welds during construction.

    b. 1958, Line 300B: Seam leak in DSAW pipe.

    c. 1964, Line 132: A leak was found on a "wedding band" weld; the leak was the result of a construction defect. The defect was found on segment 200.

    d. 1974, Line 300B: Hydrostatic test failure of seam weld with lack of penetration (similar to accident pipe).

    e. 1988, Line 132: Longitudinal seam defect in DSAW pipe.

        i. On March 1, 1989, PG&E's Technological and Ecological Services (TES) sent a memorandum which stated that a 30" section of Line 132 had been "removed for failure analysis because of a pinhole leak in the longitudinal seam weld." (CCSF Testimony I.12-01-007 at p. 5)

        ii. The memorandum finds that "overall, the x-ray inspection showed the weld to be of low quality, containing shrinkage cracks and voids, lack of fusion, and inclusions. Although the actual leak could not be found, it is likely that it was related to one of the weld defects." (CCSF Testimony I.12-01-007 at p. 5)

iii. The memorandum also states that "the cracks are pre-service defects, i.e. they are from the original manufacturing of the pipe joint." (CCSF Testimony I.12-01-007 at p. 5)

iv. The leak identified constitutes a failure under the TIMP regulations. (CCSF Testimony I.12-01-007 at p. 5)

v. Upon discovering this memorandum, PG&E should have evaluated all similar pipeline for potentially unstable manufacturing and construction defects under the data gathering and integration procedures of section 192.917(b) and the analysis of the data required by the TIMP regulations. (CCSF Testimony I.12-01-007 at p. 5)

vi. PG&E admits that the pipe characteristics of this segment are essentially identical to the pipe characteristics of segment 180 as identified in its job files. (Joint Evidentiary Hearings of I.11-02-016 and I.12-01-007 Tr. Vol.4 at p. 567:23-27 (Harrison)).

vii. The document shows that PG&E should have been aware of both potential manufacturing and construction defects present on Line 132. (CCSF Testimony I.12-01-007 p. 6).

viii. This memorandum should also have raised concerns regarding PG&E's quality control procedures at the time this segment was installed in 1948. (CCSF Testimony I.12-01-007 at p. 5)

ix. PG&E should have reviewed its records for other similar pipe segments installed at approximately the same time to determine the extent of the quality control issue. (CCSF Testimony at p. 6, 8.)

f. 1992, Line 132: Longitudinal seam defect in DSAW weld when a tie-in girth weld was radiographed.

g. 1996, Line 109: Cracking of the seam weld in DSAW pipe.

  i. In this metallurgical report, PG&E found evidence of cracking in its girth welds from 2 spools removed from Line 109. The report failed to identify the exact segments from which the spools were removed. The report states "the spools are believed to be from gas transmission line 109 which was installed in 1935." One of the cracks was found to be 76.5% of the wall thickness. (CCSF Testimony I.12-01-007 at p. 12)

h. 1996, Line 109: Seam weld with lack of penetration (similar to accident pipe) found during camera inspection of a 22-inch segment of Line 109 gas pipe along Miranda Avenue in Palo Alto.

  i. Several of the findings include "linear crack-like indication, about ½ inch long ... in the toe of a flush-ground, seam repair weld," "another linear indication, 4 inches long, ... in the base metal about ½ inch away from the seam," and "[i]ncomplete root penetration ... in the seams of several spools. In two spools it extends intermittently for the entire spool length." (CCSF Testimony I.12-01-007 at p. 12)

  ii. The 1996 video inspection also reveals that there are longitudinal seam defects in the form of incomplete root penetration on Line 109 that range from one foot in length to seven feet in length. In some instances, the incomplete root penetration was intermittently present for 19 feet. (CCSF Testimony I.12-01-007 at p. 12)

iii. These reports should have raised concern regarding the stability of both girth and longitudinal welds in PG&E's system for these pipelines and pipelines of similar vintage. Given the uncertainty regarding the welding present on Lines 101 and 109, PG&E should have taken extra precautions to ensure that it was providing safe service. (CCSF Testimony I.12-01-007 at p. 12)

i. 1996, DFM-3: Defect in forge-welded seam weld.

j. 1999, Line 402: Leak in ERW seam weld.

k. 2002, Line 132: During a 2002 ECDA assessment, miter joints with construction defects were found on Segment 143.4.

l. 2009, Line 132: A leak was found on Segment 189 that was caused by a field girth weld defect. Segment 189 was originally fabricated by Consolidated Western using DSAW and installed in 1948.

m. 2009, Line 132: During the ECDA process, a defective SAW repair weld was found on Segment 186. As indicated in PG&E's pipeline survey sheet, the segment was originally fabricated by Consolidated Western using DSAW and installed in 1948.

n. 2011, Line 300A: Longitudinal seam crack in 2-foot pup of DSAW pipe (found during camera inspection).

o. 2011, Line 153: Longitudinal seam defect in DSAW pipe during radiographic inspection for validation of seam type.

61. PG&E failed to consider the additional following documents as part of its integrity management program when it developed its initial baseline assessment plan:

a. 1965 Weld evaluation re: Line 109 girth weld.

i. The report found that the oxy-acetylene weld on a section of 26 inch diameter pipe on Line 109 in San Francisco did not meet the minimum requirements of the (then) current A.P.I. Standard 1104, and that excessive carbon in the weld metal caused the failure. This should have raised concern regarding the presence of oxy-acetylene welds elsewhere in PG&E's system. (CCSF Testimony I.12-01-007 at p. 11)

b. 1975 Laboratory test reports re: Line 101 girth welds.

i. These lab test reports from 1975 discuss brittle failure on four unidentified segments of Line 101 constructed with oxyacetylene welds, and two unidentified segments of Line 109 constructed with arc welds. (CCSF Testimony I.12-01-007 at p. 11)

ii. For the segments removed from Line 101, the 1975 reports note "weld defects present in fracture of all test specimens (porosity, lack of fusion, and slag includions (sic)). Some shear fracture present at all test temperatures." (CCSF Testimony I.12-01-007 at p. 11)

iii. For the segments removed from Line 109, the report notes "weld defects present in fracture of all test specimens (porosity, lack of fusion and slag inclusions). No shear fracture present in specimens tested at +70° or +100 ° F, some shear fracture present in specimens tested at +185° F." (CCSF Testimony I.12-01-007 at p. 11)

62. When an operator performs destructive testing on a weld, one of the criteria it is testing is whether the failure occurs outside of the actual weld and the heat affected zones. Several of these reports show that the girth welds are failing in the welded area which confirms that the welds of that vintage are suspect, being weaker than the parent metal. (CCSF Testimony I.12-01-007 at p. 12)

63. PG&E either failed to properly review its records and discover the reports identified above or it improperly discounted the importance of the findings in the

reports, and failed to document the reasons why the reports were not relevant. (CCSF Testimony I.12-01-007 at p. 11)

a. For example, because the 1989 memorandum identified pre-service defects in 30", DSAW pipe installed in 1948, PG&E should have been concerned that its quality control was deficient at the time this segment was installed in 1948. (CCSF Testimony I.12-01-007 at p. 6)

b. PG&E did not evaluate and take conservative steps to address the uncertainty raised by the failure report. PG&E did not document how it performed these analyses. (CCSF Testimony I.12-01-007 at p. 6)

c. Based on this memorandum, PG&E should have known that a segment of Line 132, installed in 1948, had experienced seam failure, and that other similarly older pipelines were known to have longitudinal seam related defects that should not be ignored. (CCSF Testimony I.12-01-007 at p. 6)

d. The 1989 memorandum demonstrates that PG&E should have been aware of both potential manufacturing and construction defects present on Line 132. (CCSF Testimony I.12-01-007 at p. 6).

64. The other memoranda further demonstrate that PG&E should have been concerned with manufacturing and construction defects on Lines 101, 109 and 132. (CCSF Testimony I.12-01-007 at p. 10)

65. PG&E should have documented how it evaluated and took conservative steps to address the fact that these reports suggest that defects may also be present on other pipe of similar vintages. (CCSF Testimony I.12-01-007 at p. 6)

66. These documents confirm the existence of manufacturing and construction defects in its system, and should have raised particular concern regarding pipeline with similar characteristics and of similar vintage.

67. PG&E does not have records of post construction field pressure tests for many of these older pipes. (CCSF Testimony I.12-01-007 at p. 8)

68. Prior to September 9, 2010, PG&E's Integrity Management Plan did not properly identify and require assessment of unstable manufacturing and construction threats. (CCSF Testimony I.12-01-007 at p. 9)

69. As of September 10, 2010, PG&E had identified 11.15 miles of piping to be assessed for manufacturing seam threats, but had only actually assessed 4.9 miles of pipeline using Transverse Field Inspection. (CCSF Testimony I.12-01-007 at p. 9)

70. In March 2012, PG&E identified an additional 523 pipeline segments that it admits have unstable manufacturing and construction defects. As of March 2012, PG&E had not yet assessed those defects. (CCSF Testimony I.12-01-007 at p. 9)

71. In San Francisco alone there are 6 segments on Line 101, totaling approximately one mile (5,333 feet) in length, that have unstable manufacturing or construction defects. These segments were all installed in 1953. (CCSF Testimony I.12-01-007 at p. 9)

72. There are also 22 segments on Line 109, amounting to nearly 2 miles (9,781 feet) of pipeline, that have unstable manufacturing or construction defects. Most of these segments were installed in 1932, and many have oxy-acetylene welds, which have been identified as being susceptible to brittle like cracking. (CCSF Testimony I.12-01-007 at p. 9)

73. These segments with oxy-acetylene welds in San Francisco are not included in Phase I of PG&E's recently filed Pipeline Enhancement Safety Plan, and will not be addressed by 2014 under PG&E's current proposals. (CCSF Testimony I.12-01-007 at p. 9)

74. Because PG&E is still recovering records, there may still be other segments that PG&E has not appropriately identified as having unstable manufacturing or construction defects. (CCSF Testimony I.12-01-007 at p. 9)

75. PG&E now proposes to assess 247,206 feet of pipeline or over 46 miles of pipeline for manufacturing and construction defects. (CCSF Testimony I.12-01-007 at p. 9)

76. One reason why PG&E now needs to urgently assess such a large amount of pipe is the fact that historically, PG&E did not proactively investigate the manufacturing and construction defects on its system. (CCSF Testimony I.12-01-007 at p. 10)

77. Many of those segments PG&E now considers unstable should have been considered high risk and assessed by December 17, 2007. (CCSF Testimony I.12-01-007 at p. 10)

78. Due to the age and the uncertain condition of these pipelines, and applying conservative judgment, PG&E was required to develop a plan to assess and mitigate the potential manufacturing and construction defects associated with vintage pipelines in its system. (CCSF Testimony I.12-01-007 at p. 10)

79. (p.34) PG&E's 2004 Baseline Assessment Plan (BAP) did not identify a construction threat based on "wedding band" joints in its threat algorithms.

80. (p.38) PG&E's Likelihood of Failure (LOF) algorithm did not include threats from internal corrosion, stress corrosion cracking, equipment failure, incorrect operations (including human error), and cyclic fatigue.

81. (p.38; p.50) PG&E dismissed cyclic fatigue as a threat based on a report prepared for PHMSA on the stability of manufacturing and construction defects. PG&E did not incorporate cyclic fatigue or other loading conditions into their segment specific threat assessments and risk ranking algorithm.

82. Tracking pressure cycles is necessary because increasing and decreasing the pressure can affect the stability of manufacturing and construction (especially weld) defects in pipeline segments. (CCSF Testimony I.12-01-007 at p. 16)

    a. The first step for any operator to evaluate the potential threat posed by cyclic fatigue is to track its pressure histories. The operator must consider the changes or variations in pressures and related stress levels on the pipeline and track the percent increase or decrease caused by the change in pressure. (CCSF Testimony I.12-01-007 at p. 17)

b. Next, the operators must identify what constitutes a significant threat due to severe or moderate pressure/stress cycles. Operators must count the number of severe cycles experienced by the pipeline. (CCSF Testimony I.12-01-007 at p. 17)

c. All operators must perform this analysis, and although failure due solely to cyclic fatigue is rare, the effects due to pressure cycling should be considered as part of an operator's evaluation of interactive threats. (CCSF Testimony I.12-01-007 at p. 17)

83. The Gas IM Rule contains a requirement that all gas operators consider the impact of operational pressure cycles when evaluating cyclic fatigue pursuant to 192.917(e)(2).

84. PG&E did not track its pressure histories. (CCSF Testimony I.12-01-007 at p. 16)

85. Without tracking the pressure histories, PG&E is unable to determine if it exceeded the five-year maximum operating pressure of its pipelines. (CCSF Testimony I.12-01-007 at p. 16)

86. If PG&E is unable to determine if it exceeded the five-year maximum operating pressure for the pipelines, PG&E is unable to perform the analysis required by section 192.917(e)(3) and 192.917(e)(4). (CCSF Testimony I.12-01-007 at p. 16)

87. PG&E was unable to evaluate the threat of cyclic fatigue on its lines. (CCSF Testimony I.12-01-007 at p. 18)

88. When a pipeline operator concludes that a particular threat is not applicable to its pipeline, the threat evaluation must be documented and the basis for drawing such conclusions must be documented. (CCSF Testimony I.12-01-007 at p. 18)

89. PG&E should have documented and addressed the significance of the missing data regarding pressure history. Taking into consideration that the MAOP may have been exceeded, in the absence of data, a conservative operator would assume that the threat applies to the line being evaluated. (CCSF Testimony I.12-01-007 at p. 18)

90. Once PG&E determined that it was not tracking pressures, it should have performed an evaluation of the cyclic fatigue threat on its pipelines. (CCSF Testimony I.12-01-007 at p. 18)

91. PG&E still does not incorporate pipeline pressure and flow data into its integrity management risk procedure. (CCSF Testimony I.12-01-007 at p. 18)

92. PG&E has not carefully monitored its pressures, and does not consider pipeline pressure and flow data in its integrity management model. (CCSF Testimony I.12-01-007 at p. 15)

93. Even though PG&E was required to track over-pressurization events with the advent of the Integrity Management rules, PG&E states that it only "began tracking over-pressurization events in the Gas Events database in September 2008." (CCSF Testimony I.12-01-007 at p. 15)

94. Because PG&E did not track over-pressurization events prior to 2008, it can only estimate that it experienced approximately 10 to 20 untracked over-pressurization events each year. (CCSF Testimony I.12-01-007 at p. 15)

95. PG&E also admitted that it does not have pressure histories for the entire year of 1999. (CCSF Testimony I.12-01-007 at p. 15)

96. PG&E stated that "PG&E did not incorporate the loss of the 1999 SCADA pressure records into its integrity management model as pipeline pressure and flow data are not directly incorporated into the integrity management risk model. The reason the risk model does not directly incorporate pressure and flow data is that the condition those records might provide information about, cyclic fatigue in a pipeline, is considered to be a low likelihood event for pipelines carrying natural gas." (CCSF Testimony I.12-01-007 at p. 15)

97. (p.50) The NTSB report described the initial defect on Pup 1, and the stages by which the defect grew to failure. The initial crack-like defect extended longitudinally along the entire length inside of the weld (the root) on Pup 1, resulting in a net intact seam thickness of 0.162 inches. With a nominal 0.375

inch wall thickness, the intact wall thickness was approximately 43% at the weld. There was also an angular misalignment on the inside of Pup 1). Given this initial defect, an additional 2.4 inch defect grew to failure. As noted in Figure 21 of the NTSB report, the initial crack-like defect first grew by ductile fracture (Stage 1). Then the crack grew by fatigue (Stage 2). The final stage was the rupture of the pipe, identified in the photo as quasi-cleavage fracture (Stage 3).

98. (p.40) PG&E increased the pressure on many lines, including Line 132 to a little over the system MAOP ("pressure spiking") so that it could eliminate the need to consider manufacturing and construction threats as unstable as a result of increasing the pressure above the 5 year maximum operating pressure (MOP).

99. PG&E asserted that it did so "to avoid [pressure testing] and any potential customer curtailments that may result," and therefore "PG&E has operated, within the applicable five-year period, some of its pipelines that would be difficult to take out of service at the maximum pressure experienced during the preceding five-year period in order to meet peak demand and preserve the line's operational flexibility." (CCSF Testimony I.12-01-007 at p. 14)

100. Identifying manufacturing and construction threats as unstable would mean that an assessment method capable of assessing seam, girth weld, and other manufacturing and construction anomalies would need to be used (hydro-testing or In-Line-Inspection).

101. (p.40) On two occasions, PG&E isolated Lines 132 and 109, and raised the pressure to a little over the Line 132 system MAOP (pressure spiking) of 400 psig. Within the City and County of San Francisco alone:

   a. On December 11, 2003, PG&E spiked the pressure on segments of Line 109 to 150.01 psi. (CCSF Testimony I.12-01-007 at p. 15)

   b. Prior to December 11, 2003, the five-year MOP for Line 109 segments 195.2 to 248 was 149.8 psi. (CCSF Testimony I.12-01-007 at p. 15)

c. Under 192.917(e), any pressure increase, regardless of amount, requires that the segment to be prioritized as high risk. (CCSF Testimony I.12-01-007 at p. 15)

d. Based on this spike, the segments on Line 109 in San Francisco with potential manufacturing defects should have been considered unstable, and should have been prioritized for a hydrostatic pressure test assessment. (CCSF Testimony I.12-01-007 at p. 15)

e. Despite the fact that the December 11, 2003 spike exceeded the five-year MOP for Line 109, PG&E did not identify the manufacturing and construction threats in these lines as unstable and a high risk. (CCSF Testimony I.12-01-007 at p. 15)

102. (p.41) PG&E's risk-ranking algorithm in Risk Management Protocol (RMP) -06 does not consider DSAW pipeline as having manufacturing defects, including seam and pipe body defects.

103. (p.41) A report entitled "Integrity Characteristics of Vintage Pipelines", referenced by PG&E in its first revision of RMP-06, identifies DSAW as having manufacturing defects, including seam and pipe body defects. Table E-6 in the "Vintage Characteristics of Pipelines" report identifies Consolidated Western as a manufacturer of DSAW pipe that has had incidents for both pipe body (1950 and 1954-56) and seam welds during certain years (1947, 1950, 1954-56).

104. (p.43) PG&E's implementation of the ECDA process along Line 132 shows that some high consequence areas (HCAs) were identified and designated as such by PG&E before December 2003.

105. (p.44) PG&E operated Line 132 to approximately 400 psig in order to establish a maximum baseline value on two occasions. PG&E operated the line at 402.37 psig on December 11, 2003; PG&E also operated Line 132 at 400.73 psig on December 8, 2008. The point on the system where these pressures were measured was identified as MMT_PT0083: MLPTS-TER L132 PRESS. This point is at the Milpitas Terminal.

106. (p.46) In the 2004 BAP, PG&E identified Segment 180 as not having any DSAW manufacturing threat.

107. PG&E did not evaluate or analyze the interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time). (CCSF Testimony I.12-01-007 at p. 19)

108. Interacting threats can result in otherwise stable defects becoming unstable, and necessitate assessment. (CCSF Testimony I.12-01-007 at p. 19)

109. PG&E assumed that the manufacturing and construction defects in its system were stable, and failed to consider the interactive nature of the threats on its lines, or how changing pressures could affect the stability of the manufacturing and construction defects. (CCSF Testimony I.12-01-007 at p. 19)

110. PG&E identified approximately 457 miles of HCA pipeline as having a potential manufacturing threat in its 2004 Baseline Assessment Plan. PG&E identified approximately 400 miles of HCA pipeline as having a manufacturing threat in its 2009 Baseline Assessment Plan. (TURN Direct Testimony, I. 12-01-007, April 24, 2012, p. 10-11.)

111. PG&E's Integrity Management Program plan stated the Company's "desire to inspect pipelines utilizing in-line inspection (ILI), whenever it is physically and economically feasible." [RPM 06, Sec. 5.4]

112. Notwithstanding this stated intention, of the 357 miles of pipeline with identified manufacturing threats that PG&E assessed between 2002 and 2010, PG&E assessed 323 miles using external corrosion direct assessment, 34.4 miles using in-line inspection, and 10.4 miles using pigging. [PG&E Response to TURN DR 001-03 in R.11-02-019].

113. When the grandfathering provision was enacted in 1970, there was an expectation that pipeline operators would have pressure test records to substantiate their pipelines' historic maximum operating pressure. (CCSF Testimony I. 11-02-016 at p. 4)

114. There was also an understanding that certain levels of safety were being provided by means of class location design factors that limited the maximum pressure based on test pressures and the population density of the route along the pipeline. The Department of Transportation believed operators had a working knowledge of the requirements of the industry safety code ANSI B31.8 applicable to gas pipelines and had applied these requirements to their design, construction and operating practices. (CCSF Testimony I. 11-02-016 at p. 4)

115. When the Department of Transportation enacted the regulations, it expected that operators would have detailed records of pipe and components be able to calculate MAOP based on the weakest element in the pipeline system, or that operators would have pressure test records to validate the MAOP. (CCSF Testimony I. 11-02-016 at p. 7)

116. The Department of Transportation allowed grandfathered pressures because it assumed the pipelines that would operate pursuant to the grandfather clause would primarily be those pipelines that had been installed from 1935 to 1951 and (a) either applied lower class location design factors than the industry applied since 1952 up until the 1968, or (b) only been tested to 50 psi above the MAOP. (CCSF Testimony I. 11-02-016 at p. 7)

117. If the operators lacked pressure test records and the operator could not determine the MAOP based on the weakest element, the Department of Transportation would not have considered the historic operating pressure to be safe. (CCSF Testimony I. 11-02-016 at p. 8)

118. Numerous records concerning the basis for PG&E's maximum operating pressures and code compliance activities are unaccounted for, misplaced or just missing. (CCSF Testimony I. 11-02-016 at p. 4)

119. Pressure test records for many pipelines are missing and instead PG&E relies upon statements about operating pressures (and not actual test pressure charts and related test pressure or operating pressure documents) to form the basis for establishing maximum pressures. (CCSF Testimony I. 11-02-016 at p. 4)

120. PG&E's witness in Rulemaking 11-02-019 stated that of its pipelines located in high consequence areas operated pursuant to the grandfather clause, the MAOP for 50-70% of those pipelines is established by affidavit. (CCSF Testimony I. 11-02-016 at p. 8)

121. Even though affidavit is acceptable at the discretion of regulatory agencies, using a notarized statement in lieu of pressure charts, or inspection reports increases the level of uncertainty associated with gas pipeline operations. (CCSF Testimony I. 12-01-007 at p. 4)

122. The fact that PG&E used affidavits to establish the MAOP for the majority of grandfathered pipelines located in high consequence areas is unusual, reflects poorly on the state of PG&E's records, and is an abuse of the regulation. (CCSF Testimony I. 12-01-007 at p. 4)

123. If PG&E had to use affidavits to establish the historic MAOP, it should have taken extra precautions to ensure the integrity of its pipeline system. (CCSF Testimony I. 11-02-016 at p. 9)

VI. PG&E Records for Line 132 and Segment 180

124. In 1956, PG&E followed ASA B.31-1.8 (1955) and API standards. PG&E so stated to the Commission in 1955. (CPSD DR 15 – A 6)

125. In 1956, as part of construction project number GM 13647; PG&E installed Segment 180 in pipeline Line 132, which is the segment that failed on September 9, 2010. (CPSD Ex. 2, p. 2)

126. PG&E's Geographic Information System (GIS) incorrectly identified the failed pipe segment as seamless pipe. (CPSD Ex. 2, p. 1)

127. PG&E cannot document the origin of the pipe used in the construction of Segment 180, the segment that failed. (PG&E Ex. 61)

128. PG&E has never verified that all of the pipe in Segment 180 met specifications for X42 or X52 pipe. (CPSD DR 3 A 11)

129. PG&E has identified no policies, standards or guidelines pertaining specifically to the "chemical composition required of a pipe…before it can be re-conditioned and/or re-used." (CPSD DR 2 A 5)

130. The lack of records about reused pipe is a safety issue in part because salvaged pipe may have longitudinal weld quality problems from original manufacturing or stress after installation. (CPSD Ex. 4, p. 3)

131. Operating a facility without the basic knowledge of its construction, including the source of pipe and the types of welds used in the manufacture of the pipe is inherently unsafe because it is impossible to accurately determine safe operating parameters such as the maximum operating pressure. (CPSD Ex. 4, p. 3)

132. The type and quality of the welds in Segment 180 project GM 136471 were unknown from 1956 until PG&E inspected the pipe in 2011, after the San Bruno explosion. (CPSD Ex. 4, p. 3)

133. PG&E records reveal that some of the pipe installed in the 1956 project GM 136471 was salvaged and reconditioned from other pipelines in PG&E's system, but do not reveal the previous locations of the pipe or its age. (CPSD Ex. 2, p. 44, Figure 5, fn. 181)

134. PG&E has not established that it knows the previous service or use, if any, of the failed pipe used in Segment 180. (PG&E p. 4-2)

135. Some of PG&E's early accounting and engineering documents kept track of salvaged and reused pipe. (CPSD Ex. 2, p. 43-44, fn. 178, CPSD Ex. 4, p. 2)

136. Accounting records for holding accounts created from 1951 through 1966 kept track of new and salvaged pipe. (CPSD Ex. 4, p. 2)

137. PG&E has located no records related to project GM 136471 on Segment 180 in its holding account records from the 1950's. (CPSD Ex. 4, pp. 2-3)

138. PG&E cannot explain why the records of the Segment 180 project are not included in the holding account records located from the 1950's. (CPSD Ex. 4, p. 3)

139. Some PG&E construction drawings include notes about pipe having been salvaged and abandoned and about small pieces of pipe having been welded together at Milpitas Storage Area before being delivered to a construction site. (CPSD Ex. 2, p. 44, fn 179)

140. Milpitas yard delivered pipe and equipment that had been received by and temporarily stored at the Milpitas terminal. (CPSD DR. 30, A 25)

141. Records show that PG&E accumulated miscellaneous sections of 30” OD pipe, including pups of a weight and length consistent with the pipe installed in Segment 180, in the Milpitas storage yard from 1954–1956. (CPSD Ex. 4, p. 3)

142. Records show that PG&E had at least one piece of 30” OD pipe in the Milpitas storage yard in 1955, identified as “short pups and scrap” and a note that it was “junked.” (CPSD Ex. 4, p. 3)

143. PG&E cannot determine from its records what happened to the piece of 30” OD pipe in the Milpitas storage yard in 1955 that was identified as “short pups and scrap.” (CPSD Ex. 4, p. 3)

144. PG&E’s policy for handling junk pieces of pipe intended for scrap included the option for reuse of the scrap pipe on jobs. (CPSD Ex. 4, p. 3)

145. PG&E’s records do not preclude the possibility that PG&E installed the piece of junk pipe from the Milpitas storage yard, identified as “short pups and scrap,” in Segment 180. (CPSD Ex. 4, p. 3)

146. A possible source of pipe for the 1956 construction project on Segment 180 is reuse of the pipe that had been spanning San Bruno Canyon. (CPSD Ex. 4, p. 4)

147. The possible reuse of the pipe from the section of Line 132 that had spanned San Bruno Canyon is troublesome because that span of pipe had been subject to external physical stresses. (CPSD Ex. 4, p. 4)

148. Records in Job Files include various types of accounting documents and notes on project documents and construction drawings that show the salvaging, reconditioning and abandoning of pipe. (CPSD Ex. 2, p. 44)

149. PG&E has located in its records no internal specifications for reconditioning pipe from 1948 to 1956. (CPSD DR 3, A 10)

150. PG&E states that some reconditioned pipe may have been used in Segment 180 construction in 1956, but PG&E's records do not permit it to conclusively establish whether this occurred. (CPSD DR. 3, A 10)

151. PG&E once had tracking capability for pipe because there are notes on project face sheets stating that pipe is to be salvaged or abandoned and also stating the original installation projects and date of the pipe. (CPSD Ex. 2, p. 44, fn. 180, Appendix 6 to CPSD Ex. 2 report; CPSD Ex. 4, p. 2)

152. A Job File created in the 1950's was for the sole purpose of tracking PG&E's pipe inventory, both new and reconditioned. (CPSD Ex. 2 pp. 2 and 44, see fns. 178 – 180; CPSD Ex. 4, p. 2)

153. PG&E does not have detailed construction records for the 1956 project GM 136471, installing the pipe segment that ultimately failed on September 9, 2010. (CPSD Ex. 4, p. 5)

154. Some Job Files for PG&E projects in the 1950 – 1960 period show that PG&E kept detailed construction records at that time. (CPSD Ex. 4, p. 5)

155. PG&E acknowledges that the construction records it has located for Segment 180 do not contain documents or drawings that depict the Segment 180 installation in granular detail. (PG&E Ex. 61 p. 4-4)

156. The Job File for GM 136471 is an accounting file that does not contain any of the typical records expected to be in a construction project file, such as construction drawings, plans, correspondence or details of the construction project. (CPSD Ex. 4, p. 5)

157. Job Files for PG&E pipeline projects, both before and after GM 136471, show installation of small pieces of pipe welded together and pups. (CPSD Ex. 4, p. 5)

158. The Job File for the GM 136471 project should show the small pieces of pipe welded together and pups that were installed in the project. (CPSD Ex. 4, p. 5)

159. PG&E should have created and retained detailed construction records for project GM 136471. (CPSD Ex. 4, p. 5)

160. If PG&E created a file that included detailed construction records for project GM 136471, the file has since been lost. (CPSD Ex. 2, p. 5)

161. PG&E does not believe that drawings depicting the existence and orientation of the pups in Segment 180 were ever created (CPSD DR 41 – A 10)

162. PG&E cannot explain how or when between 1952 and 1956, San Bruno Creek was filled. (CPSD Ex. 4, p. 6)

163. PG&E has no explanatory or supporting documentation regarding how or when the San Bruno Creek canyon was filled, although such records would typically have been added to the Job File for a construction project such as GM 136471. (CPSD Ex. 4, p. 6)

164. PG&E is required to retain pressure test records for the life of the facility. (CPSD Ex. 4, p. 6)

165. Pressure test records confirm that the pipe is fit for service at a specific operating pressure. (CPSD Ex. 4, p. 6)

166. Available records do not reveal whether PG&E conducted a post-installation pressure test on Segment 180. (CPSD Ex. 4, p. 6)

167. PG&E's GIS system shows that Segment 180 was pressure tested with gas in 1961, but PG&E has not located any records related to a 1961 gas test. (CPSD Ex. 2, pp. 20, 48, fn. 193; PG&E Ex. 61 p. 4-6)

168. Based on a 1956 PG&E Standard Form for Strength Test Pressure Reports, PG&E was creating pressure test records as a matter of policy in 1956. (CPSD Ex. 4, pp. 6 –7)

169. If PG&E conducted any pressure or leak test on Segment 180 and completed the standard form, PG&E has since then lost that form and all test results. (CPSD Ex. 4, p. 7)

170. The MAOP records for Line 132 are incomplete. (CPSD Ex. 2, p. 6)

171. PG&E had conflicting MAOP records for Line 132 from 1978 to 2004. (CPSD Ex. 4, p. 8, PG&E Ex. 61 p. 4-11)

172. PG&E cannot produce underlying records to explain why it set the MAOPs of some parts of Line 132 at 390 psi and other parts at 375 psi and operated its system with these values in place for at least 30 years. (CPSD Ex. 4, p. 8)

173. PG&E's Standard Practice 1606, dated August 1965, shows the MAOP of Line 132 to be 400 psi. (CPSD Ex. 2, p. 3)

174. The MAOP for Line 132 remained set at 400 psi until 1976. (CPSD Ex. 2, p. 3)

175. In an August 15, 1978 internal letter, PG&E corrected the Line 132 MAOP to 390 psi between Mile Posts 35.84 and 46.59. In PG&E's MAOP Binder, which served as the record for MAOPs of all PG&E transmission lines, this 390 psi MAOP was documented as the MAOP for this section of Line 132 from 1978 to 2003. (CPSD Ex. 2, p. 3)

176. In association with the 1978 letter, the revised MAOP of 390 psi was entered into a hand-written MAOP log for Line 132 between Mile Posts 35.84 and 46.59 and on the official MAOP list, drawing 086868. (CPSD Ex. 2, p. 3)

177. PG&E's 1978 action to lower the MAOP on one section of Line 132 effectively redefined Line 132 into two sections. (CPSD Ex. 2, p. 4)

178. On a second version of the hand-written MAOP log for Line 132, someone lined out the entry of 390 psi and wrote "400 psi," adding a note dated December 10, 2003 saying, "See note – based on 10/16/68 & 10/28/68 Milpitas Term Records." (CPSD Ex. 2, p. 3)

179. A list of revision numbers, includes Revision 15.4, and has the notation: "Updated Line 132 MAOP to 400 psig, RTA 12/10/03" in handwriting that matches the note found on the second version of the historical MAOP log that was edited. (CPSD Ex. 2, p. 5)

180. PG&E did not file a request with the CPUC to uprate the MAOP from 390 to 400 psi for the section of Line 132 between Mile Posts 35.84 and 46.59. (CPSD Ex. 2, p. 5)

181. The site of the 2010 San Bruno explosion, Segment 180, is within the section of Line 132 between Mile Posts 35.84 and 46.59. (CPSD Ex. 2, p. 4)

182. The MAOP for the section of Line 132 between Mile Posts 1 and 35.84 was 400 psi from (at least) 1965 to September 2010. (CPSD Ex. 2, p. 4)

183. PG&E has not explained the distinction between the two sections of the pipeline, as revealed in its historical records. (CPSD Ex. 2, p. 6)

184. PG&E should have validated the MAOP before changing it, but there is no record indicating that it did so. (CPSD Ex. 2, p. 6)

185. If PG&E had hydrotested line 132 to uprate the pressure to 400 psi on the section from MP 35.84 to MP 46.59, the line would have failed during the test, the pipe would have been replaced, and the San Bruno explosion would not have occurred. (CPSD Ex. 4, p. 8)

186. The "clearance process" is PG&E's detailed records procedure for conducting maintenance projects that could potentially disrupt service, such as the Milpitas work on September 9, 2010. (CPSD Ex. 2, p. 6)

187. PG&E's written clearance documentation prepared for the electrical work at Milpitas terminal for September 9, 2010 did not meet the written requirements of PG&E's clearance procedure. (CPSD Ex. 4, p. 9, PG&E Ex. 61 p. 4-15, lines 4-6)

188. The written clearance application prepared for the electrical work at Milpitas Terminal for September 9, 2010, did not designate a clearance supervisor or fully describe the work to be performed and the sequence of operations that would be undertaken. (CPSD Ex. 4, p. 9, PG&E, p. 4-13)

189. The only notes from the electrical procedure performed on September 9, 2010 are provided in a list of numbers hand-written on a couple of pages without context or

apparent order, written by the contract electrical engineer who was overseeing the work. (CPSD Ex. 4, p. 10)

190. On September 9, 2010, at the time the San Bruno pipe failed when it was over pressured, PG&E maintenance personnel were performing maintenance on the electronic systems of the fully operating Milpitas Terminal without the benefit of the required written step-by-step plan for the work that would be undertaken in the maintenance procedure. (CPSD Ex. 2, p. 6-7, CPSD Ex. 4, p. 9)

191. Subsequently, when problems occurred in the electrical system, personnel at Milpitas and in the San Francisco Control Room lacked the records of the maintenance sequence that could have helped them determine and resolve the cause of the problems. (CPSD Ex. 4, p. 9)

192. PG&E has stated that pressure readings at Milpitas on September 9, 2010 from approximately 1805 to 2100 were "potentially inaccurate" because of Milpitas work. (CPSD DR 5, A 2)

193. It is possible that an adequate Clearance Procedure could have prevented the electrical problem that led to the over pressuring of the Peninsula pipelines and, thus, could have prevented the San Bruno explosion from occurring. (CPSD Ex. 4, p. 9)

194. PG&E has listed approximately 14,600 documents, totaling approximately 121,000 pages scanned at Milpitas Terminal in April 2010. PG&E cannot state with certainty whether those scanned documents represent all the documents that were at Milpitas Terminal on September 9, 2010, nor can PG&E state whether the inventory of records is exhaustive of all categories of records that PG&E stored and maintained at Milpitas as of September 9, 2010. (CPSD DR 1, A 7)

195. When PG&E schedules work to be performed on its electrical system it is essential that personnel have up-to-date versions of all relevant records, including an Operating and Maintenance manual. (CPSD Ex. 2, p. 8)

196. In a summary inventory of documents at the Milpitas Terminal in 2011, PG&E listed a 1991 Operating and Maintenance manual described as "issued 1991, January 2011 update." (CPSD Ex. 2, p. 8 CPSD Ex. 4, p. 10)

197. Because the January 2011 update was not issued until 2011, the manual available at the terminal on September 9, 2010 would have been Version 0, the 1991 manual, without the 2011 update. (CPSD Ex. 4, p. 10)

198. Other than the manual noted in the records inventory, PG&E has produced no record of which manual was available at the terminal on September 9, 2010. (CPSD Ex. 4, p. 10)

199. When asked for copies of all records kept at the Milpitas Terminal as of September 9, 2010, PG&E did not include an operations manual in its response. (CPSD Ex. 4, p. 10)

200. PG&E cannot conclusively determine that the then-current version of the O&M manual was at the Milpitas Terminal on September 9, 2010. (CPSD Ex. 4, p. 10, PG&E Ex. 61, p. 4-17, line 31 through p. 4-18, line 2)

201. When trying to control pressure by manually opening or closing valves during the emergency at the Milpitas Terminal on September 9, 2010 PG&E personnel needed to have access to current and accurate drawings of the facility. (CPSD Ex. 2, p. 9)

202. Drawing #383510 is a drawing on paper that shows the general arrangement of piping, valves, flow meters and other equipment such as separators at the Milpitas Terminal. (CPSD Ex. 4, p. 11)

203. PG&E provided to NTSB a version of drawing # 383510 that was updated after September 9, 2010 to reflect the general arrangement, as it existed at the terminal on September 9, 2010. (CPSD Ex. 2, p.9, fn. 38, CPSD Ex. 4, p. 11)

204. The paper drawing that was available at the terminal on September 9, 2010 was an outdated version. (CPSD Ex. 2, p. 9, fn. 38, CPSD Ex. 4, p. 11)

205. The data transmission collection and display system that provides data to the control rooms for PG&E's gas transmission system is referred to as Supervisory Control And Data Acquisition (SCADA). (CPSD Ex. 2, p.11)

206. On September 9, 2010 San Francisco Control Room operators were alerted by SCADA alarms from instruments at the Milpitas Terminal and along the Peninsula pipelines indicating high pressures. (CPSD Ex. 2, p. 11)

207. The control room policy is for the operator to acknowledge all alarms and then analyze the problem and respond within 10 minutes. (CPSD Ex. 2, p. 11)

208. On September 9, 2010 there were long screens of repeating alarms and many went unacknowledged. (CPSD Ex. 2, p.11, fn. 50, PG&E Ex. 61, p. 4-26, lines 12-14 and p. 4-26, lines 18-19)

209. At 6:15, a few minutes after the pipeline ruptured in San Bruno, there was a low-pressure alarm from Martin Station, which indicated the pipe failure. (CPSD Ex. 2, p. 11.)

210. Even after finding the pressure drop, operators could not identify the location of the pipe failure using SCADA data. (CPSD Ex. 2, p. 12.)

211. The line schematic diagram for the Milpitas Terminal that was viewed by the San Francisco Control Room Operators on the SCADA display on September 9, 2010 was inaccurate and incomplete. (CPSD Ex. 2, p. 9, fn. 39, CPSD Ex. 4, p. 11)

212. The line schematic drawing on the SCADA display shows the pipelines, open/closed status of valves, and other information relevant for operating the gas system. (CPSD Ex. 4, p. 11)

213. The SCADA diagram of the Milpitas Terminal that is used by the San Francisco Control Room Operators has been revised three times since September 9, 2010. (CPSD Ex. 2, p. 9, fn. 39)

214. PG&E added the 30-300 By-pass line to the schematic SCADA display after September 9, 2010, but the bypass line should have been on the display diagram viewed by gas control operators on September 9, 2010. (CPSD Ex. 4, p. 11)

215. The 30-300 By-pass line was built in 1954 outside the Milpitas Terminal fence south of the terminal. (CPSD Ex. 4, p. 12)

216. The 30-300 By-pass line was installed for emergency purposes so that PG&E could completely by-pass the terminal and supply gas to the Peninsula in the event that the terminal became inoperative. (CPSD Ex. 4, p. 12)

217. Although the 30-300 By-pass line was installed for use when there was an emergency at Milpitas Terminal, it was not visible to control room operators on the SCADA display diagram on September 9, 2010. (CPSD Ex. 4, p. 12)

218. The diagrams available to Gas Control operators should include all lines designed and installed for use during emergencies. (CPSD Ex. 4, p. 12)

219. The absence of the By-pass line on the SCADA display diagram during the emergency of September 9, 2010 was a safety issue. (CPSD Ex. 4, p. 12)

220. Due to PG&E's recordkeeping shortfalls, operators may have lacked the data essential for fully understanding what was happening in its gas transmission system when things went wrong at the Milpitas Terminal. (CPSD Ex. 4, p. 14)

221. Control room operators did not know whether there were valves on Line 132 that could shut off the gas at the site of the San Bruno pipe explosion. (CPSD Ex. 2, p. 12)

222. Because they failed to detect the pipe failure, could not immediately determine its exact location and were unfamiliar with the location of valves, control room operators could not provide useful information to field personnel and managers. (CPSD Ex. 2, p. 12)

223. On September 9, 2010 the Milpitas Terminal lost programming to three controllers at 5:20 p.m. (CPSD Ex. 2, p. 10, 11)

224. Despite PG&E's then existing policy to keep back-up copies of the software programs on a floppy diskette at the terminal, on September 9, 2010, PG&E had no back-up copy of the program at the terminal. (CPSD Ex. 2, p. 10)

225. The PG&E maintenance person at the terminal could not reload the program from his laptop because his software was not compatible with the model number of the three controllers that lost programming. (CPSD Ex. 2, p. 10)

226. An engineer, called to the terminal to bring the software on his laptop computer, did not restore the system until midnight. (CPSD Ex. 2, p.11)

227. The gas technician at Milpitas Terminal on September 9, 2010 did not have the software needed to reprogram the three valve controllers that experienced problems. (CPSD Ex. 4, p. 14)

228. Records from the evening of September 9, 2010 show that operators at Gas Control and the maintenance personnel believed there was a relationship between the loss of controllers and the pressure increase, including on Line 132. (CPSD Ex. 4, p. 15)

229. The delay in restoring the programming to the controllers, may have delayed the resolution of the high-pressure problem. (CPSD Ex. 4, p. 15)

230. It is an unsafe and poor engineering practice to have the only accessible copy of critical software on a laptop stored remotely from the programmed equipment. (CPSD Ex. 2, p. 11)

231. Operating a safe gas transmission system requires emergency plans that can be readily understood and followed in an emergency. (CPSD Ex. 2, p. 13)

232. PG&E's Gas Control Room emergency plan published on September 30, 2011, provides the authority to control room operators to notify interconnects, independent storage providers, and large customers following a significant, abnormal, or emergency event. The same plan provides no authority or responsibility for control room operators to notify fire or police departments of such events. (CPSD DR 39 – A 4 Attach. 1, pp. 3 and 4)

233. PG&E's Emergency Response Plans were lengthy, difficult to use and were a source of confusion on September 9, 2010. (CPSD Ex. 2, pp. 12, 15)

234. The September 9, 2010 incident shows the emergency response plan to be ineffective in guiding personnel during the initial phases of the emergency. (CPSD Ex. 4, pp. 15 - 16)

235. The transcript of the audio recording made in the San Francisco Control Room during the emergency reveals that there was confusion about the Emergency Response Plan. (CPSD Ex. 2, p. 13)

236. In reviewing the summary reference pages of the Emergency Response Plan, it is not clear who in PG&E was supposed to be in charge of the response to the San Bruno incident, a level 4 emergency. (CPSD Ex. 2, p. 13)

237. The overpressure checklist is vague regarding the type of situation to which it applies. (CPSD Ex. 4, p. 16)

238. The overpressure checklist fails to give a timeframe for allowing the problem to continue before taking the first step to minimize danger. (CPSD Ex. 4, p. 16)

239. The fire/explosion checklist fails to identify who may or should shut off the gas. (CPSD Ex. 4, p. 16)

240. Only a person who knows exactly where the valves are and has the proper set of access keys can shut off the gas to a main gas line. Therefore it is imperative that someone be directed to contact the person with the knowledge and the keys immediately upon learning of a pipe failure. (CPSD Ex. 4, p. 16)

241. Based on the response time to turn off the gas and the fact that the responders only responded because they happened to see the situation on a TV news broadcast, it is evident that the emergency plan failed to serve the needs of PG&E employees and the public. (CPSD Ex. 4, pp. 16-17)

242. PG&E documented operating Line 132 in excess of 390 psi on December 11, 2003, December 9, 2008 and September 9, 2010. (CPSD Ex. 4, p. 17)

243. On December 11, 2003 and December 9, 2008 PG&E purposely pressured Line 132 to 400 psig and held it at this level for two hours each time to trigger a five-

year period in which it believed it could operate Line 132 at an MAOP of 400 psig. (CPSD Ex. 4 , p. 17)

244. On September 9, 2010 PG&E allowed Line 132 to be over pressured to at least 394 psig as a result of problems at the Milpitas Terminal. (CPSD Ex. 4, p. 17)

245. The September 9, 2010 high pressure event ended when the pipe in San Bruno failed. (CPSD Ex. 4, p. 17)

246. On September 11, 2010 PG&E's General Counsel issued instructions to preserve and retain all paper and electronic documents related to the September 10, 2010 incident and to prevent its DVR (Digital Video Recorder) from automatically deleting. (CPSD Ex. 3, p. 4 and Appendix A)

247. On September 13, 2010 the Commission's Executive Director ordered PG&E to preserve records related to the September 9, 2010 incident. (CPSD Ex. 3, p. 4)

248. On September 23, 2010 the Commission issued Resolution no. L-403 in which Mandate 7 required PG&E to preserve all records related to the September 9, 2010 incident. (CPSD Ex. 3, p. 4)

249. On October 10, 2011 PG&E stated that video records at the Brentwood facility were retained on a digital video recorder until automatically overwritten after about 60 days. (CPSD Ex. 3, p. 2, CPSD Ex. 4, p. 18)

250. On October 10, 2011 PG&E stated in a data response that the video recording from the Brentwood facility for September 9 and 10, 2010 had been automatically overwritten. (CPSD Ex. 3, p. 2, CPSD Ex. 4, p. 18)

251. On February 6, 2012 PG&E stated in a data response that it did not believe that any PG&E employee or agent reviewed, between September 9, 2010 and November 10, 2010, what was on the security videotape from the Brentwood facility. CPSD Ex. 3, p. 2)

252. On March 9, 2012 PG&E provided a revised response stating that it had "recently learned" that Camera 6, the video camera inside the Brentwood Terminal's Alternate Gas Control, was not configured properly and, therefore, did not record

onto the Digital Video Recorder, thus no video from Camera 6 had been recorded on September 9, 2010 or subsequently overwritten. (CPSD Ex. 4, p. 18)

253. On March 9, 2012 PG&E stated in its revised data response that it had "recently examined" the five outdoor cameras at Brentwood Terminal and found video from approximately 110 days before the examination. (CPSD Ex. 4, p. 19)

254. On March 9, 2012 PG&E stated in its revised data response that it had inspected Camera 6 and confirmed that no video was recorded onto the Digital Video Recorder. (CPSD Ex. 3, p. 4, CPSD Ex. 4, p. 19)

255. On March 9, 2012, PG&E stated that there was no video recording from Camera 6 at the Brentwood Terminal for September 9, 2010. (CPSD Ex. 3, p. 3 CPSD Ex. 4, p. 18)

256. PG&E does not assert in either of its data responses that it took any steps to comply with the preservation order of the Commission. (CPSD Ex. 4, p. 19)

257. PG&E did not take timely action to preserve any Brentwood Terminal video recording that may have existed pursuant to the September 11, 2010 instruction of its General Counsel. (CPSD Ex. 4, p. 18)

258. PG&E did not take timely action to preserve any Brentwood Terminal video recording that may have existed pursuant to the September 13, 2010 Commission Executive Director order. (CPSD Ex. 4, p. 18)

259. PG&E did not take timely action to preserve any Brentwood Terminal video recording that may have existed pursuant to the September 23, 2010 Commission Resolution no. L-403. (CPSD Ex. 4, p. 18)

260. PG&E made inaccurate and contradictory statements to the Commission regarding the video recording of Camera 6 at the Brentwood Terminal. (CPSD Ex. 4, p. 19-20)

261. The first data response suggests that PG&E knew as a certainty that the Camera 6 video was recording and overwriting, while the second response shows that PG&E made no attempt to check whether Camera 6 was recording, or whether

overwriting was preventable in order to preserve the video as evidence. (CPSD Ex. 4, p. 19)

262. Before the second response, and assuming no video recording had ever been made, PG&E made no first hand investigation to determine whether the Brentwood Camera 6 video recording had been destroyed. (CPSD Ex. 4, p. 19)

263. If PG&E's second response was accurate, then PG&E's first response was false and misled the Commission. (CPSD Ex. 4, p. 20)

264. When asked in CPSD DR 8 Q 8 (d) (PG&E Ex. 61 Exhibit 5-13) to identify personnel who had access to particular diagrams on September 9, 2010 PG&E's answer did not include all personnel who had access. (CPSD Ex. 4, pp. 21-22.)

265. When asked in CPSD DR 30, Q 2 to provide the names of maintenance personnel and the maintenance supervisor who were headquartered at the Milpitas Terminal in September 2010, along with their hours and the work they performed on September 9, 2010, PG&E named the supervisor, and indicated that he had been there earlier in the day, but did not say that he was also there in the evening. (CPSD Ex. 3, p. 8, fn. 11, CPSD DR 30, A 2)

266. According to the San Francisco Control Room transcript, the supervisor was present at Milpitas Terminal after 5 p.m. (CPSD Ex. 3, p. 8, fn. 12)

267. PG&E's responses to CPSD DR 8 Q8 (d) and CPSD DR 30, Q 2 were not complete because they did not identify all of the people in Milpitas handling the pressure problem on September 9, 2010. (CPSD Ex. 4, pp. 20 – 22)

268. From at least as early as 1929, PG&E retained its engineering documents from construction projects in Job Files. (CPSD Ex. 2, p. 32)

269. PG&E's Job Files are its primary source of data about the construction of its pipelines. (CPSD Ex. 2, p. 33)

270. An intact Job File should contain detailed records of individual construction projects. (CPSD Ex. 4, p. 23)

271. Job Files serve as PG&E's only contemporaneous source of records for individual segments of pipeline in its transmission system. (CPSD Ex. 4, p. 23)

272. The master Job File is the file of record. (CPSD Ex. 2, p. 32, fn. 126)

273. The Job Files should contain data and information that is required for successful risk assessment of PG&E's pipelines. (CPSD Ex. 2, p. 33)

274. The loss of, or the inability to locate or access, a Job File represents the loss of virtually all of the information about a particular construction project, which includes the physical characteristics and the status of that segment of pipe as of the date of the project. (CPSD Ex. 4, p. 23)

275. Many PG&E Job Files are missing. (CPSD Ex. 2, p. 32, fn. 128, CPSD Ex. 4, p. 23)

276. Many PG&E Job Files are incomplete. (CPSD Ex. 4, p. 23)

277. Incomplete Job Files are labeled with the project number but are lacking many of the records that must have been in the file at the time of construction, such as design and construction drawings, x-ray and pressure test reports. (CPSD Ex. 4, p. 23)

278. Many existing master Job Files are incomplete because they do not include records such as leak and pressure test results, x-ray results for field welds, field inspection logs and notes or specific information about how the pipe itself was constructed. (CPSD Ex. 2, p. 32, CPSD Ex. 4, pp. 22 – 23)

279. Some master Job Files lack a clear and unambiguous record or notation regarding the source of piping in the referenced job. (CPSD Ex. 2, p. 3)

280. If pipe has been previously used, its history and pipe characteristics are critically important to assessing its remaining life when it is placed back into service. (CPSD Ex. 2, p 32)

281. California regulations dating back to 1912 and Federal regulations dating back to 1970 require PG&E to retain facility records permanently. (CPSD Ex. 2, p. 32)

282. Many individual records that should have been preserved in Job Files were misplaced or destroyed from 1980 through 1996. (CPSD Ex. 2, p. 32)

283. PG&E cannot determine which records are missing or the time period in which they were lost. (CPSD Ex. 2, p.33, PG&E quote, fn. 130)

284. "Life of the pipeline" records may have been misplaced or discarded. (CPSD Ex. 2, p.33, PG&E quote, fn. 130)

285. Missing Job Files and missing Job File information are critical to safety, especially because PG&E has identified Job Files as its primary source of information about pipeline characteristics. (CPSD Ex. 4, p. 23)

286. PG&E has lost Job File records and has lost track of some Job File record numbers issued over time. (CPSD Ex. 4, p. 23)

287. PG&E did not keep a running record of Job File numbers with associated job titles. (CPSD Ex. 4, p. 24)

288. Some Job File numbers were used to name accounting files such as tracking piping and other capital assets. (CPSD Ex. 4, p. 24)

289. PG&E may have discarded or misplaced records designated to be kept for the life of the pipelines. (CPSD DR 4- A 4 and 5)

290. The Job File for the 1956 Crestmoor project that installed Line 132, Segment 180 has only two drawings, neither of which contains details about the construction of the segment. (CPSD Ex. 2, p. 29)

291. The Job File for the 1956 Crestmoor project that installed Line 132, Segment 180 contains no supporting documentation regarding the pipe used, the quality assurance/quality control performed or any other test or inspection performed. (CPSD Ex. 2 p. 29)

292. In 1967 PG&E submitted to the PUC, pursuant to General Order 112-B, a document titled "Pipeline Surveillance Procedures and Records, and History File Description." (CPSD Ex. 2, p. 28)

293. PG&E's "Pipeline Surveillance Procedures and Records, and History File Description" describes PG&E's method of keeping pipeline data. (CPSD Ex. 2, p. 29, quote, fn. 114)

294. Some of the drawings that pre-date the mid 1970's contain detailed information about pipelines. (CPSD Ex. 2, p. 29)

295. Many early drawings are missing and many others, including older drawings associated with projects performed in house by PG&E, lack detail and supporting documentation. (CPSD Ex. 2, p. 29)

296. In December 1969, PG&E formalized its pipeline history policy into Standard Practice 463.7, "Pipeline History File, Establishing and Maintaining." (CPSD Ex. 2, p. 29)

297. PG&E stated the purpose of the Pipeline History File was "to provide a current and uniform history record for pipelines (and mains) that have a Maximum Allowable Operating Pressure resulting in a hoop stress equal to or greater than 20% of the Specified Minimum Yield Strength. (CPSD Ex. 2, p. 29)

298. Standard Practice 463.7 included a detailed list of the records and reports to be included in the Pipeline History File. (CPSD Ex. 2, pp. 29 - 30)

299. Standard Practice 463.7 required the pipeline or main history file to include the date of original installation and dates of subsequent changes requiring work orders or GM estimates; and design and construction data covering the original installation and subsequent revisions requiring work orders or GM estimates. (CPSD Ex. 2, p. 30, Standard Practice 463.7, point 6)

300. Accurate and complete pipeline files would have provided a means to accurately and promptly prioritize pipe replacement using the risk assessment model approach. (CPSD Ex. 2, p. 30)

301. Standard Practice 463.7 was included in PG&E's 1986 Pipeline Survey Manual, which also included detailed instructions for creating records titled "pipeline Survey Sheets." (CPSD Ex. 2, pp. 30 - 31)

302. On October 9, 1987, PG&E issued an internal memo advising that Standard Practice 463.7 was cancelled. (CPSD DR 34, A 1, Atch 5). Based upon this memo, PG&E stated "It is PG&E's understanding that Standard Practice No. 463.7 was canceled no later than October 9, 1987." (CPSD DR 34, A 1).

303. PG&E states that it believes Standard Practice 463.7 became inoperative in the early 1990's when PG&E initiated the transition to its electronic Geographic Information System. (CPSD Ex. 2, p. 31)

304. Based upon its understanding that Standard Practice Number 463.7 was eliminated, PG&E stated that it "is unable to state what steps it took to ensure that all information kept and maintained pursuant to Standard Practice No. 463.7 would continue to be available. . ." (CPSD DR 34, A 1)

305. On February 14, 1996, PG&E issued a History File Requirements Manual. ("Manual") According to PG&E, "The attached manual is a revision to the old PLO HFR Manual that outlined record keeping requirements for all gas transmission facilities." This manual included Standard Practice 463.7, from 1969, in its entirety. (P2-1477, pp. 63-70)

306. PG&E no longer maintains Pipeline History Files. (CPSD Ex. 2, p. 31)

307. PG&E has not produced any Pipeline History Files in this proceeding. (CPSD Ex. 2, p. 31, PG&E Ex. 61 p. 1-1)

308. PG&E has not explained when or how it stored or disposed of the Pipeline History Files. (CPSD Ex. 2, p. 31)

309. PG&E is not able to provide a summary list with locations of all pipeline files that were kept and maintained pursuant to Standard Practice No. 463.7. (CPSD DR. 34 – A 1)

310. PG&E has concluded that some gas transmission records may have been misplaced, discarded, or destroyed in connection with moves, but that PG&E has been unable in all instances to conclusively determine which records are missing or the precise time period in which they were lost. (CPSD DR 34 – A 1)

311. PG&E excludes previous pipe history data from its risk assessment models. (CPSD Ex. 2, p. 32)

312. Design and pressure test records are vital to the successful implementation of PG&E's integrity management risk assessment model. (CPSD Ex. 2, p. 33)

313. PG&E cannot confirm whether pipes today for which PG&E cannot now locate verified strength pressure test records, were untested or whether they were tested and records cannot now be located (CPSD DR 13 – A 12).

314. PG&E is missing many of its design and pressure test records. (CPSD Ex. 2, p. 33 CPSD Ex. 4, p. 29, PG&E Ex. 61 p. 1-1)

315. As of December 28, 2011, PG&E had identified 1,935 transmission segments that had no record documentation in GIS of either test pressure, pressure test date, or both. PG&E assumes that these 1,935 segments were installed without a construction hydrostatic pressure test. (CPSD DR 194 –A 12)

316. Pressure testing was common at PG&E long before the 1950's. (CPSD Ex. 4, p. 30)

317. ASME B31.1.8, adopted in 1955, established as accepted industry practice the post-installation pressure testing of transmission pipeline segments and the retention of the pressure test records for the life of the segment. PG&E's failure to retain such records contrary to the accepted standards of ASME B31.1.8 was and is imprudent.

318. By 1956, PG&E had developed a standard form (Form #75-27) to record pressure tests – both gas and hydrotests. (CPSD Ex. 4, p. 30, footnote149)

319. General Order 112, effective July 1, 1961, required post-installation pressure testing of transmission pipeline segments and the retention of the pressure test records for the life of the segment.

320. PG&E incorporated design and test requirements for piping systems into its Standard Practices at least as early as 1965. (CPSD Ex. 2, p. 33)

321. PG&E also followed ASME and API guidelines. (CPSD Ex. 2, p. 33)

322. Standard Practice 1604, section 30 (1965) states "[t]he copy of the Strength Test Pressure Report filed with the completed foreman's copy of the estimate shall be retained for the life of the facility. (CPSD Ex. 2, p. 34, citing CPSD DR 18, A8, Atch. 1)

323. Standard Practice 1604 was updated in 1970 and renamed A-34, Drawing Number 087712. (CPSD Ex. 2, p. 34)

324. Federal regulations, 49 C.F.R. Part 192, Subpart J, adopted in August 1970, require post-installation pressure testing of transmission pipeline segments and the retention of the pressure test records for the life of the segment.

325. The 1983 A-34 policy cites 49 CFR 192.101 and 192.501, in addition to CPUC GO 112. (CPSD Ex. 2, p. 34)

326. Standard Practice A-34, section 25 requires that "a chart record shall be made of the pressure test for all lines or systems being uprated and for new or reinstated facilities to operate at or over 30% Specified Minimum Yield Strength." (CPSD Ex. 2, p. 34)

327. Standard Practice A-34, section 25.1 requires, "[t]he original of the test chart is to be attached to the original of the Test Report Form 62-4921. (CPSD Ex. 2, p. 34)

328. PG&E's latest Standard Practice A-34 policy, dated 2003, still includes a record retention clause with wording similar to that of the 1983 version requiring the record to be retained for the life of the facility. (CPSD Ex. 2, p. 34)

329. Notwithstanding the provisions of ASME B31.1.8, GO 112 and 49 C.F.R. Part 192, Subpart J, PG&E does not have pressure test records for many segments installed from 1955 to the present.

330. On August 30, 2012, PG&E identified 23,760 of its pipe segments, constituting approximately 435.7 miles, within Class 3 and 4 High Consequence Areas, which lacked strength test records required by law and sound engineering practice. (CPSD and TURN Joint DR 1, A 1, Atch 1, August 30, 2012)

331. PG&E has no procedure to create and maintain records of pipe repaired or replaced after the pipe fails a hydrotest. (CPSD DR 14 – A 5)

332. Weld records are an integral part of the construction record for any pipeline installation project and should be kept in the Job File. (CPSD Ex. 4, p. 31)

333. Because weld inspection data is reported based on weld number, the only way to locate the weld at a later time is to have a weld map that shows the location of each weld identified by weld number. (CPSD Ex. 4, p. 31)

334. Weld maps and inspection records for PG&E's transmission pipelines would normally be a source of key pipeline data for the integrity management risk assessment model, but are mostly missing. (CPSD Ex. 2, p. 34)

335. Weld inspection records would serve as an alternative source of information in situations where other source records were not made or not retained. (CPSD Ex. 4, p. 31)

336. Weld inspection reports are an important source of information about the quality of welds. (CPSD Ex. 2, p. 36)

337. Weld information on a joint-by-joint basis would be a good source of information to identify potential weak links in pipeline segments, thus would provide a basis for conservative assumptions about welds in the integrity management model. (CPSD Ex. 4, p. 31)

338. PG&E's records retention policy calls for retaining weld inspection reports for the life of the facility. (CPSD Ex. 2, p. 34)

339. In practice, PG&E does not retain x-ray films beyond about 5 years. (CPSD Ex. 2, p. 34)

340. A thorough review of many Job Files in PG&E's new Enterprise Compliance Tracking System database revealed that PG&E has very few weld maps, although they should have been retained in the master Job File according to PG&E's policies. (CPSD Ex. 2, p. 35)

341. Each Job File for transmission piping should include a weld inspection report that summarizes the results of an inspection when the pipe was installed. (CPSD Ex. 4, p. 32)

342. PG&E has not retained many weld inspection reports. (CPSD Ex. 2, p. 36)

343. Some weld records are missing entirely. (CPSD Ex. 4, p. 32)

344. The operating pressure history, showing high and low pressures under normal operating conditions, is a critical record for natural gas pipelines. (CPSD Ex. 2, p. 37)

345. PG&E's Risk Management Procedure requires pipeline operating pressure records for risk assessment. (CPSD Ex. 2, p. 37)

346. Pressure history recordkeeping is crucial to other considerations in integrity management, such as weld integrity. (CPSD Ex. 2, p. 38)

347. PG&E keeps some pressure excursion information in abnormal incident reports, but these reports are not integrated into a particular historical record of operating pressures. (CPSD Ex. 2, p. 38)

348. PG&E has no "life of the plant" history of operating pressures. (CPSD Ex. 2, p. 38)

349. PG&E has only pressure data from 1998 through the present day, except that 1999 pressure records are lost. (CPSD Ex. 4, p. 32)

350. PG&E recently lost pressure records for all of 1999 for all pipelines in its system. (CPSD Ex. 2, p. 38)

351. Because it lost all 1999 pressure records, PG&E cannot give an accurate accounting of pressure excursions above MAOP for any pipeline in its system, which means the company cannot accurately assess the condition of any of its pipelines. (CPSD Ex. 2, p. 38)

352. Specific missing pressure records are needed for PG&E to operate a meaningful and useful Integrity Management program. (CPSD Ex. 4, p. 32)

353. PG&E's Integrity Management procedure requires historic pressure records to determine the risk related to internal corrosion. (CPSD Ex. 4, p. 32)

354. The Pipeline Engineer must consider operating pressure history in flow model calculations. (CPSD Ex. 4, p. 32)

355. The absence of complete lifetime historical pipeline pressure data makes it impossible for the pipeline engineer to consider this history in performing flow model calculations associated with identifying Dry Gas Internal Corrosion Direct Assessment regions. (CPSD Ex. 4, pp. 32 – 33)

356. Recordkeeping requirements throughout PG&E's history apply to PG&E's records, whether or not the records are used in the new Integrity Management program. (CPSD Ex. 4, p. 32)

357. Information about past leaks in existing pipelines is a category of data fundamental to predicting likely leaks in those pipelines in the future. (CPSD Ex. 2 p. 39)

358. PG&E's policy for A-forms (leaks) is to keep them for the life of the asset (CPSD DR 4 – A 2)

359. PG&E cannot retrieve transmission pipeline leak data prior to 1970. (CPSD Ex. 2, p. 39)

360. PG&E has failed to maintain leak records in a manner that makes the information readily accessible. (CPSD Ex. 2, p. 39) (PG&E Ex. 61 3-64)

361. For pipelines that have not had a post construction pressure test, it is essential that the number and type of leaks on that pipeline be known. (CPSD Ex. 2, p. 39)

362. Leak data is critical to determining stability. (CPSD Ex. 2, p. 39)

363. The risk of allowing leaks to go unattended include exposing people to harmful gas, the potential for explosions and total pipe failures such as the San Bruno incident in September 2010. (CPSD Ex. 2, p. 41)

364. PG&E has had a leak detection program since at least 1958. (CPSD Ex. 2, p. 41, CPSD Ex. 4, p. 33)

365. Leaks on pipeline segments were recorded and PG&E was keeping track of the leaks at one time because there are references to tallies of the number of leaks on a pipeline. (CPSD Ex. 4, p. 33)

366. Generally, Job Files do not contain A-Forms or other leak report forms. (CPSD Ex. 4, p. 33)

367. Even though it had a leak detection program, PG&E failed to document and save the data in a way that made the data retrievable. (CPSD Ex. 2, p. 41)(PG&E Ex. 61 3-64)

368. A review of PG&E's various "A-Forms," used to collect leak information, reveals inconsistent reporting, incomplete reports and poor follow up. (CPSD Ex. 2, p. 39)

369. Incomplete A-Forms are equivalent to missing records. (CPSD Ex. 4, p. 33)

370. PG&E's leak records and databases are not fully integrated, so that in January 2012 PG&E could not count the total number of leaks classified by status/grade across its entire transmission system or along any transmission pipeline in the system. (CPSD DR 40 – A 2 and A 3, and CPSD DR 23 A 15 Supplement 1)

371. When the data from the A Forms was uploaded to databases, PG&E found that it was unable to include the historical data from one database to the next and thus ended up with at least three different databases containing different sets of leak data, in addition to paper records. (CPSD Ex. 2, p. 40)

372. PG&E's A-Form reports are poorly managed, inconsistent and incomplete. (CPSD Ex. 2, p. 40)

373. ECDA pre-assessment data base only lists a leak cause for one out of 13 leaks. (CPSD Ex. 2 p. 39)

374. Leak data is relevant to Integrity Management processes generally. (CPSD Ex. 4, p. 34)

375. PG&E reduced the significance of leak data in the Integrity Management process from 1984 to the present day. (CPSD Ex. 4, p. 34)

376. Beginning in 1984, leak history made up 15% of the weighted data in the Integrity Management Model risk calculation. (CPSD Ex. 4, p. 34)

377. In 2009, leak history made up 0.5% of the weighted data in the Integrity Management Model risk calculation. (CPSD Ex. 4, p. 34)

378. PG&E has been unable to locate valid leak data to use in its risk assessments. (CPSD Ex. 4, p. 34)

379. PG&E does not consider leaks on other segments more distant than a mile from the leak, regardless of whether those more distant pipe segments have the same vintage pipe, same characteristics, and same manufacturer as the leaking pipe. (CPSD DR 12 – A 5)

380. PG&E does not maintain a comprehensive master list of all repaired leaks of its transmission system. (CPSD DR. 23 – A 25)

381. PG&E has identified more than 65 leaks in line 132 that occurred between pipeline installation and through September 13, 2011. (CPSD DR CPUC 180 –A 1, and Supplement 1)

382. The 2008 PG&E audit found that PG&E's "leak per mile performance metric creates a disincentive to maximize the number of leaks found on survey." (CPSD DR 42–A6, Attach.1)

383. PG&E is not aware of any program under which it paid bonuses to employees solely on the number of identified leaks per mile or other similar metric. In the past PG&E used leaks and leak repairs per mile as among numerous metrics that were tracked and considered in computing incentive pay or salary. Leaks repaired per mile were weighted as 5-7% or less of the total score, depending on year, and the total score was used in incentive pay. (CPSD DR 42–A 6)

384. PG&E states it never intended leak count performance metrics to be a potential disincentive for reporting leaks. To avoid any potential disincentive to report leaks, in 2008 PG&E eliminated this performance metric. (CPSD DR 42–A 6)

385. It is always prudent to keep track of where older pipe is within a gas transmission system. (CPSD Ex. 2, p. 43)

386. PG&E has located no written policies in place prior to September 2010 for tracking salvaged or reused transmission pipe. (CPSD DR 16 – A 1)

387. Over the years, PG&E has moved pipe from one location to another within its system without keeping records of where the pipe was reinstalled; therefore, it is now impossible to determine the age of pipe in any segment. (CPSD Ex. 2, p. 42, PG&E Ex. 61 p. 3-32)

388. PG&E now has pipe operating in its system that may not be satisfactory for continued service. (CPSD Ex. 2, p. 43)

389. In order to re-use pipe safely PG&E would need to have conducted proper inspection, repair and testing prior to re-use. (CPSD Ex. 2, p. 42, fn. 172 quoting PG&E)

390. PG&E never implemented a program to inspect, repair and test used pipeline prior to re-use. (CPSD Ex. 2, p. 43)

391. PG&E states that it never has had policies to track salvaged, reused and/or reconditioned pipe within its system. (CPSD Ex. 2, p. 43, fn. 177 – 179)

392. It appears that PG&E's early accounting and engineering documents did keep track of salvaged and reused pipe. (CPSD Ex. 2, p. 43, fn. 177 – 179)

393. Because of early accounting and engineering documents that recorded salvaged and reused pipe, PG&E had tracking capability, but at some time in the past lost track of these records. (CPSD Ex. 2, p. 44)

394. PG&E should have maintained the detailed accounting records that could have been used to determine where salvaged pipe was reused within the pipeline system. (CPSD Ex. 4, p. 35)

395. PG&E sent a letter to the Commission in 1944 stating that it had retained permanently the original copy of records recording each material and

disbursement requisition covering withdrawal of material and return of salvage material. (CPSD Ex. 4, p. 35, footnote 172)

396. PG&E acknowledged in the 1944 letter to the Commission that it was required, as of 1912, to permanently retain the records. (CPSD Ex. 2, p. 35)

397. The detailed records described in the 1944 letter to the Commission are missing. (CPSD Ex. 4, p. 35)

398. Because PG&E was creating detailed records of where pipe was reused within its system, it should still have them. (CPSD Ex. 4, p. 35)

399. The records described in PG&E's 1944 letter to the Commission could have been used to trace the location of the installation of salvaged pipe that was reused within PG&E's pipeline system. (CPSD Ex. 4, p. 35)

400. Based on review of thousands of documents in the Enterprise Compliance Tracking System database, it appears that sometime in the 1980's PG&E lost the ability to track salvaged pipe. (CPSD Ex. 2, p. 45)

401. Because of the lack of records about the location of salvaged pipe, PG&E cannot determine that pipe specifications data entered into its integrity management risk assessment model is accurate for every pipe segment, therefore, creating an ongoing safety risk associated with using the model to prioritize pipe projects based on likelihood of failure or highest risk. (CPSD Ex. 2, p. 47)

402. Since 1999, PG&E's Geographic Information System (GIS) replaced most of PG&E's paper records for documenting facility data. (CPSD Ex. 2, p. 47)

403. PG&E used pipeline survey sheet information to populate GIS. (CPSD DR 23–A 3)

404. PG&E does not maintain records indicating when it relied only on pipeline survey sheets to populate GIS, and when it used other sources of information. (CPSD DR 23–A4)

405. In limited instances PG&E also used Job Files to populate GIS. When information was on the pipeline survey sheets, PG&E did not use other source data to corroborate the pipeline survey sheets. (CPSD DR. 23–A 4)

406. The database for PG&E's Geographic Information System was populated with faulty data, including assumed and missing elements from earlier databases. (CPSD Ex. 2, p. 47, PG&E Ex. 61 p. 3-66)

407. GIS is the only ready and easily accessible source of data for gas control room operators and for engineers, and so it is important that GIS information be accurate. (CPSD Ex. 4, p. 37)

408. PG&E states ". . . we are aware that data errors exist within the current GIS system (either from original pipeline data or introduced during the transfer), and have established a process by which field personnel can identify data inaccuracies and update that information in GIS."(PG&E Ex. 61, p. 3-66, lines 26-29)

409. The data for the Integrity Management model is drawn from GIS. (CPSD Ex. 4, p. 37)

410. Errors in PG&E's records have been carried forward from one system to the next without checks for accuracy or, in some cases, even reasonableness. (CPSD Ex. 2, p. 48)

411. PG&E's GIS data and pipeline survey sheets include and reflect assumed, unknown, or blank values for each mile of its approximately 5,324 miles of transmission pipeline system. (CPSD DR 27 A 10, A 11, A 13)

412. Assumed, unknown, and blank values exist in GIS or pipeline survey sheets for transmission pipe characteristics of pipe wall thickness, minimum depth cover, pipe diameter, length of segment, seam type, presence of pups, pipe manufacturer, depth of ground cover over the pipeline, SMYS, and whether pipe is seamless. (CPSD DR 27 A 12, and Atch. 1)

413. PG&E has developed a process to identify potential discrepancies between entries in the current GIS and data gained from other sources, such as Job Files or filed inspections. (PG&E Ex. 61 p. 3-66)

414. Information from sources other than GIS is transmitted to the gas transmission mapping group to facilitate the updating of the current GIS. (PG&E Supplemental Response to Joint DR 1 A2, September 28, 2012)

415. Leaks identified in GIS are not placed in geographical location with perfect precision, especially in congested areas. (CPSD DR 40 A2)

416. Changes made to certain data elements in the current GIS database are automatically captured in an audit change log, which is used to track changes that may affect High-Consequence Areas (HCA) identification. (PG&E Supplemental Response to Joint DR 1 A2, September 28, 2012)

417. A PG&E spreadsheet lists records "issues and errors" that PG&E discovered during MAOP validation. They include: GIS inaccurate (cell 145), pipe segment changed (146), lack of information (148), class location inaccurate (149), material specifications inaccurate (150), map/diagram inaccurate (151), no engineer sign off (153), mile point error (154), spreadsheet version error (155), station error (156), line error (157), segment error (158), feature error (159), image error (160), reference map error (161), strength test error (162), current MAOP error (163), job number or installation date error (164), branchy name error (165), ID error (167), PLF name error (168), mainline missing error (169), pressure reports not identified (170). (CPSD DR 16 A 6 Atch 1)

418. The changes captured in the audit change log may reflect new pipe installation data, changes made to more precisely reflect the location of the pipeline, and changes to pipe attribute information, including data discrepancy corrections. (PG&E Supplemental Response to Joint DR 1 A2, September 28, 2012)

419. The change log, which contains 88,038 entries, does not categorize the reason that the change was made, but includes a comment section that may contain comments made by Risk management engineers that could provide additional information on

the reason for the change. (PG&E Supplemental Response to Joint DR 1 A2, September 28, 2012)

420. PG&E's Integrity Management group ran queries on the GIS database and identified various inaccuracies in data categories relevant to the manufacturing threat identification process on HCA pipe segments. (PG&E Supplemental Response to Joint DR 1 A2, August 1, 2012)

421. The query run on the entire GIS database identified various inaccuracies in data categories relevant to the manufacturing threat identification process on HCA pipe segments, including 203 instances of the Maximum Allowable Operating Pressure (MAOP) being listed as less than the Maximum Operating Pressure (MOP), 1271 instances where the seam type was not identified, but joint efficiency was set at 1.0, and 103 instances where the seam type was SSAW, A O.Smith, LAP, or Flash welds and the Joint Efficiency was not 0.8. (PG&E Supplemental Response to Joint DR 1 A2, August 1, 2012)

422. PG&E is not investigating the potential discrepancies identified through the query run on the entire GIS database that identified various inaccuracies in data categories relevant to the manufacturing threat identification process on HCA pipe segments.(PG&E Supplemental Response to Joint DR 1 A2, August 1, 2012)

423. PG&E cannot provide a list of all errors in its GIS database. (PG&E Supplemental Response to Joint DR 1 A2, August 1, 2012)

424. PG&E has no comprehensive effort or plan to validate the data contained in Gas View 2.0/Gas Map 2.0 or tally errors contained in it. (PG&E Supplemental Response to Joint DR 1 A2, August 1, 2012)

425. PG&E's GIS is an unreliable source of data for the integrity management risk assessment models. (CPSD Ex. 2, p. 47)

426. To the extent that the data in GIS is erroneous, the data in the Integrity Management model is also erroneous. (CPSD Ex. 4, p. 37)

427. PG&E cannot locate or identify any documentation or formal procedures relating to quality control and/or quality assurance of the data transfer from hardcopies to pipeline survey sheets, and from pipeline survey sheets to GIS. (CPSD Ex. 2 pp. 47 – 48, quote and fn. 193 citing data responses, PG&E Ex. 61 p. 3-66)

428. In the 1980's PG&E hired Bechtel to develop a model that was essentially an Integrity Management model to create a systematic mathematical approach to identifying segments of pipe that needed to be replaced. (CPSD Ex. 4, p. 37)

429. In August 1983, PG&E contracted with Bechtel to develop a pipeline replacement program "to replace major gas transmission and distribution pipelines which have a higher potential for failure, and where there would be high potential for injury and/or property damage should a failure occur. These pipelines were constructed with either oxygen – acetylene, bell-bell and chill ring, or bell and spigot girth welds, and are located in populated areas." (CPSD DR 34 A 2, Attachment 1, October 1, 1987 letter to PG&E from Bechtel – G. R Mayer)

430. In 1983, and for the pipeline replacement project, PG&E and Bechtel expected to research and review approximately 80,000 project files to categorize transmission and distribution systems by location, year of operation, type of pipe by manufacturer, specification (size, wall thickness, grade, longitudinal weld type, type of girth weld, failure and repair history, MAOP and MOP, class location defined by G.O. 112, pipe test history, condition of pipe from records, proximity of other pipeline systems, future expansion plans, local PG&E recommendations for replacement, SMYS, and certain kinds of pipes built before 1947. (CPSD DR 34 A 2, Atch 1, October 1, 1987 letter to PG&E from Bechtel – G. R Mayer)

431. After a review at PG&E, Bechtel advised PG&E that "information on the manufacturer, type of soil and condition of pipe would be hard to obtain unless the pipe is uncovered." (CPSD DR 34 A 2, Atch 1, October 1, 1987 letter to PG&E from Bechtel – G. R Mayer)

432. In 1983 Bechtel informed PG&E that "hydrostatic test duration information was extremely difficult to obtain accurately". PG&E explained to Bechtel that "this

information was required to determine where retesting to comply with the present law was necessary. Bechtel was instructed to find as much information as possible." (CPSD DR 34 A 2, Atch 1, October 1, 1987 letter to PG&E from Bechtel – G. R Mayer at 01-000008763)

433. Bechtel proposed to include factors in risk analysis pertaining to pipe diameters with a history of failure and year of pipe installation. PG&E "considered these proposals unnecessarily complicated and requested work to be directed towards a more simplified approach." (CPSD DR 34 A 2, Atch 1, October 1, 1987 letter to PG&E from Bechtel – G. R Mayer at 01-000008766)

434. In December 1984, PG&E "also requested the divisions to review the data base output and try to fill in the many openings where no information had been found by the Bechtel field engineers. This was a last effort to complete the data base without having to uncover the pipe in the filed." (CPSD DR 34 A 2, Atch 1, October 1, 1987 letter to PG&E from Bechtel – G. R Mayer at 01-000008765)

435. The 1984 study and report, and successor studies and reports, done by Bechtel led to PG&E's later transmission line priority analysis algorithm. (CPSD DR 5-11)

436. PG&E's IM model is unreliable because PG&E lacks a complete set of good data to put into the model. (CPSD Ex. 4, p. 38)

437. PG&E cannot have a feasible or useful integrity management program without critical data from necessary records systems. (CPSD Ex. 2, p. 27)

438. The categories in which PG&E is missing critical data from its records systems are: 1) pipeline history files, 2) Job Files, 3) pipeline design and pressure test records, 4) weld maps and inspection reports, 5) operational history records, 6) leak records, and 7) salvaged and reused pipe records. (CPSD Ex. 2, p. 27)

439. PG&E maintains information regarding the dates it installed pipes rather than the dates and locations the pipes were manufactured. (CPSD DR 42 – A 4 Atch. 1)

440. PG&E has developed and modified its Integrity Management model in a way that emphasizes PG&E's risk related to third party damage to the extent that those segments rise to the top of the rankings. (CPSD Ex. 4, p. 38)

441. PG&E's model has rendered manufacturing threats, for instance bad welds, to such a low risk factor that a pipe segment with bad welds would never rise into the top 100 segments for replacement. (CPSD Ex. 4, p. 38)

442. Even if all of the data for Segment 180 in PG&E's model had been accurate prior to the San Bruno explosion, PG&E would not have inspected or replaced L:ine 132, Segment 180, as a result of its IM prioritization. (CPSD Ex. 4, p. 38)

443. The priorities that result from running the Integrity Management model with inaccurate data are erroneous, thus, it cannot be determined whether PG&E is replacing pipe that presents the highest risk. (CPSD Ex. 4, p. 38)

444. PG&E's reliance on its model for risk management of its pipelines is inherently unsafe. (CPSD Ex. 4, p. 38)

445. In 1963 there was a fire and explosion on Line 109 near the intersection of Alemany Boulevard and Nevada Street in San Francisco. (CPSD Ex. 3, p. 17, see text to footnote 154 on p. 37 of CPSD Ex. 2)

446. PG&E cannot locate the metallurgical report relating to the 1963 explosion on Line 109. (CPSD Ex. 4, p. 40)

447. In 1988 there was a weld failure on Line 132. (PG&E 61, p. 41-48)

448. PG&E did not produce the metallurgical report from the 1988 incident. CPSD Ex. 4, p. 38-40)

449. The March 5, 1989, letter about the 1988 leak shows that it had an attachment. (CPSD Ex. 4, p. 39)

450. Records indicate that in a situation where a pipe section is removed and sent to an organization for weld analysis, a complete report of tests, images and test results is produced and sent under a cover letter to the requesting organization. (CPSD Ex. 4, p. 39)

451. The March 5, 1989 letter from PG&E provided is similar to other cover letters used to transmit complete weld analysis reports that are found in PG&E's records and indicates that there is an "attachment." (CPSD Ex. 4, p. 39)

452. PG&E has not produced the attachment indicated in the March 5, 1989 letter. (CPSD Ex. 4, p. 39)

453. The attachment to the March 5, 1989 letter has been lost or discarded. (CPSD Ex. 4, p. 39)

454. Records management is inextricably tied to the governance of a business, its ability to operate legally, efficiently, and effectively, and provide traceable, verifiable and complete records. (CPSD Ex. 6, p. 4-19)

455. In the case of a utility transporting potentially flammable and explosive gas in pipes, good records management is vital to help achieve safety. (CPSD Ex. 6, p. 4-19)

456. Records management is a "professional management discipline that provides for well-structured record keeping system(s) to ensure quick and efficient access to complete, reliable, authentic and usable information when it is needed." (CPSD Ex. 6, p. 4-19, footnote 34)

457. Every member of an organization's staff should understand the principles, policies and controls that govern the maintenance, retention and disposition of their information, and be responsible for managing their information in accordance with the regulations and business requirements. (CPSD Ex. 6, p. 4-20)

458. The Generally Accepted Recordkeeping Principles referenced by Duller and North are firmly rooted in long-standing and understood information management best practices and US Federal law and case law. (CPSD Ex. 8, pp. 26 of 72 and 30 of 72)

459. As of September 10, 2010, PG&E did not have a company-wide strategy for managing its records. (CPSD Ex. 6, p. 6-26.)

460. The state of PG&E's records in September 2010 was a culmination of PG&E's recordkeeping activities over the prior six decades. (CPSD Ex. 8, p. 30 of 72)

461. Although PG&E issued Record Retention Standard Practices from the 1950s to the present day, there is no evidence of a commitment to implement, monitor or audit compliance with the standards. (CPSD Ex. 6, p. 6-26)

462. Although PG&E issued Record Retention Standard Practices from the 1950s to the present day, there is no evidence of a commitment to train people to undertake the duties related to them. (CPSD Ex. 6, p. 6-26)

463. Its historical lack of control regarding how pipeline records were managed has been a major source of risk for PG&E. (CPSD Ex. 6, p. 6-26)

464. Prior to the San Bruno pipeline rupture and fire, PG&E did not have a company-wide strategy for managing its records. Instead, the responsibility for managing records resided within each Division, and was undertaken locally by engineers and a number of document control clerks or their equivalent. (CPSD Ex. 6, p. 6-26)

465. At the time of the San Bruno pipeline rupture and fire, PG&E had a number of employees managing specific gas records in different areas of the organization, but did not have a centralized records management function. (CPSD Ex. 6, p. 6-27)

466. At the time of the San Bruno pipeline rupture and fire, no-one in PG&E's Gas Transmission Division had formal responsibility for coordinating records management across all of that Division's different business units/offices. (CPSD Ex. 6, p. 6-27)

467. As of January 3, 2012, PG&E was not able to provide full details of the staff responsible for its record-keeping across the organization between 1948 and 1967. (CPSD Ex. 6, p. 6-29, CPSD DR 25)

468. Regarding staff responsible for record-keeping during the period from 1968 to 2010, PG&E provided a list of relatively junior staff, each of whom had some responsibility. (CPSD Ex. 6, p. 6-29, CPSD DR 25)

469. Prior to 2010, PG&E does not have an infrastructure to provide staff with education and training in records management and practices such as mentoring, skills transfer or support for staff with record-keeping responsibilities. (CPSD Ex. 6, p. 6-30)

470. As of January 2012, PG&E employees lacked sufficient training on records retention requirements and processes. (CPSD Ex. 6, p. 6-30, footnote 73)

471. As of January 2012, some PG&E employees were not aware of how long to keep specific records, where to find this information, or whether a record retention schedule existed. (CPSD Ex. 6, p. 6-30, footnote 73)

472. As of January 2012, most PG&E employees were unaware of specific record retention guidelines. (CPSD Ex. 6, p. 6-30, footnote 73)

473. PG&E's record keeping practices have been deficient and have diminished pipeline safety. (CPSD Ex. 6, pp. 4 of 72 and 7 of 72)

474. PG&E failed to employ adequate records management practices to safeguard the pipeline records in its care. (CPSD Ex. 6, p. 6 of 72)

475. In 1956, it was PG&E's practice to follow the 1955 ASA B31.1.8. (CPSD DR 15 A 6)

476. In 1960, PG&E testified and represented to the California Public Utilities Commission, "that the gas utilities in California voluntarily follow the ("ASME B31.8 standards) and that the Commission did not need to make these standards mandatory. (Decision 61269, p. 4)

477. If PG&E ever ceased following ASME B31.8 standards, PG&E did not inform the Commission of that fact before this proceeding. (CPSD DR 71, A 1c)

478. PG&E established records retention requirements in 1964, 1994 and 2005 to keep line inspection reports for 3 years, although ASME standards required keeping

these inspection records for the life of the facility and, from August 1970 to June 1996, CFR also required keeping them for the life of the facility. (CPSD Ex. 6, p. 6-35, CPSD Ex. 7, p. 3 of 5)

479. In 1994, 2005, and 2008, PG&E established record retention requirements to keep line inspection reports for all non-numbered gas transmission lines for three years, although ASME standards , through 2010, required keeping them for the life of the facility. (CPSD Ex. 6, p. 6-35, CPSD Ex. 7, p. 3 of 5)

480. In 1994, 2005 and 2008, PG&E established record retention requirements to keep line patrol reports for all non-numbered gas transmission lines for three years, although ASME standards required keeping all line patrol reports for the life of the facility continuously through 2010. (CPSD Ex. 6, p. 6-35, CPSD Ex. 7, p. 3 of 5)

481. In 1964, PG&E established a record retention requirement to keep line patrol reports for three years, although the ASME standard required keeping them for the life of the facility. (CPSD Ex. 6, p. 6-36)

482. On April 16, 2010, PG&E established a records retention requirement to keep leak survey maps for nine years, although the ASME standard required keeping the maps for the life of the facility. (CPSD Ex. 6, p. 6-34)

483. In 1994, 2005 and 2008 PG&E established record retention requirements to retain gas high pressure test records for three years, although ASME standards required keeping test pressure records showing procedures used and data developed in establishing MAOP for the life of the facility. (CPSD Ex. 6, p. 6-36, CPSD Ex. 7, p. 3 of 5)

484. PG&E has not provided evidence to demonstrate that its employees received, read, and understood the retention policies and procedures given to them. (CPSD Ex. 8, p. 60 of 72)

485. PG&E reports finding weld records in 5000 Job Files, which represents only 5.7% of the 87,018 transmission Job Files held in Emeryville as reported in CPSD Ex. 6. (CPSD Ex. 8, p. 36 of 72)

486. Between 1950 and 2010 PG&E failed to implement its retention standards fully. (CPSD Ex. 6, p. 6-37, CPSD Ex. 7, p. 4 of 5)

487. Between 1950 and 2010 PG&E's Gas Transmission Division failed to educate and communicate with staff regarding retention periods and schedules. (CPSD Ex. 6, p. 6-37)

488. PG&E's pipeline integrity management program, which should have ensured the safety of the system, was deficient and ineffective because it was based on incomplete, assumed, and inaccurate pipeline information. (CPSD Ex. 8, p. 7 of 72)

489. There are thousands of Job Files missing from PG&E's master collection of job folders held in Emeryville. (CPSD Ex. 8, pp. 39 of 72 and 41 of 72)

490. The current GIS was populated with data from a secondary/tertiary source, namely the Pipeline Survey Sheets, which themselves were derived from Pipeline Density Survey Sheets, which in turn were compiled from job file information. (CPSD Ex. 8, p. 48 of 72)

491. PG&E made no attempt to validate the content of the Pipeline Survey Sheets against original data sources as part of its GIS data population exercise. (CPSD Ex. 8, p. 48 of 72)

492. A recent internal PG&E audit concluded that PG&E's controls for investigating gas leaks and odors need strengthening and recommended that PG&E improve controls over the quality of its records. (CPSD Ex. 8, p. 53 of 72)

493. The lack of required routine review of gas leak and odor investigation records inhibits PG&E's ability to detect and correct ineffective investigations. (CPSD Ex. 8, p. 53 of 72)

494. The lack of required routine review of gas leak and odor investigation records inhibits PG&E's ability to identify potentially incomplete or inaccurate documentation. (CPSD Ex. 8, p. 53 of 72)

495. As of September 2012, much of the information in the Gas Transmission Division systems was inaccurate, incomplete, or both. (CPSD DR 25 A 2(i) Supplement - Summary of Information Management Key Themes: PG&E Gas Mapping Organization , Internal PG&E report produced by PwC. [Preliminary Draft as of January 18, 2012])

496. On December 15, 1969, PG&E issued Standard Practice 463.7, titled "Pipeline History Files"(CPSD DR 7 A 9, CPSD DR 4 A 6, CPSD DR 34 A 1, CPSD DR 66 A 1, CPSD DR 67 A 11, Ex. 6, p. 6-37)

497. Standard practice 463.7 required, "History records for numbered transmission lines shall be filed by line number, with all pertinent inclusions of data shown (as required to be included as part of the history file) . . . indexed for ready reference, and cross-referenced to other permanent files, such as GM or Work Order files. (P2-1336 and Supplement P2-1337, P2-1477, p. 566)

498. Standard practice 463.7 required that "The complete pipeline and main history files shall be maintained up to date by the Division or department for the life of the operating facility."(P2-1336)

499. PG&E is not aware of any policies, standard practices, or other guidance that orders the destruction of pipeline history files. (CPSD DR 66 A 1)

500. PG&E does not know if its pipeline history files, kept pursuant to Standard Practice 463.7, were discarded or destroyed. (CPSD DR 34 A1)

501. PG&E cannot find any of its pipeline history files. (CPSD DR 34 A1).

502. If a metal failure analysis was conducted by an outside company rather than at PG&E's San Ramon facility, the report would not be deposited and kept at PG&E's metallurgical laboratory in San Ramon. It may be held at a local office, outside the company, or be missing. (CPSD DR 4 A 12; Exhibit 6, p. 6-80)

503. PG &E did not maintain control of its distributed records in its offices, and has a significant number of missing and incomplete job folders and engineering records that are unaccounted for. (Ex. 6, pp. 6-75 to 6-77)

504. The only way to access records from the period 1915 to 1995 in PG&E's analytical reports in the San Ramon library is via a manual search. (Ex. 6, p. 6-81)

505. Key metadata from 1915 to 1995 has not been digitized and such records are only accessible via a manual search. (CPSD Ex. 6, p. 6-81)

506. There is no policing of the completeness of the records held in the ATS library. (CPSD Ex. 6, p. 6-81)

507. The failure to keep and maintain all gas pipe failure metallurgical reports in San Ramon, regardless of whether the report was written in-house or by outside vendor, creates a record-keeping deficiency. (CPSD Ex. 6, p. 6-81)

508. The parties agree to the following definitions of terms and explanations of relationships for purposes of this agreement:

a. Job - Within PG&E's Gas Transmission Division the primary construction project, maintenance and other activities performed on any pipeline are grouped into discrete work packages, referred to as "Jobs".(Ex. 6, p. 6-42)

b. Job Number - Each work package or "Job" is allocated a unique "job number."(Ex. 6, p. 6-42)

c. Job Folder - Each "job's" records are stored in one or more "job folders." (Ex. 6, p. 6-42)

d. Job File – A collection of Job Folders related to the same Job Number is a Job File. PG&E also uses the term "Job File" to refer to the collection of documents related to a particular capital job number. (CPSD DR 25, A 1, p. 3)

509. PG&E's lack of records management control over the production, duplication, maintenance and control of job folders has meant that there was no complete and definitive master set of pipeline-related records that could be readily identified and located relating to any given capital project. (CPSD Ex. 6, p. 6-45.)

510. Not all job-related information is actually placed in a single job folder. Different disciplines maintain different sets of job related information in their own job folders held within their own working areas. In addition, some job information may be retained in personal files and e-mails. (CPSD Ex. 6, p. 6-61)

511. The term, "Job number" refers to a one to fourteen digit alphanumeric reference that forms the unique primary key and link between the pipeline and the documentation detailing the work undertaken on it. (CPSD Ex. 6, p. 6-43; CPSD DR 25, A1, Atch 01)

512. On December 15, 2011, PG&E stated that the master job file is the file of record. (CPSD DR 17, A5, p. 1)

513. On December 15, 2011, PG&E stated that "Job packages are the drawings, face sheets, strength test pressure reports, financial records, and other documents created or assembled by PG&E's estimating group prior to construction of the job. Copies of these records are retained in the job file." (CPSD DR 17, A5, p. 1)

514. On December 15, 2011, PG&E stated that as a general matter, the job package is included in its entirety within the master job file. (CPSD DR 17, A 5, p. 1)

515. On February 15, 2012, PG&E stated that, prior to its MAOP validation review efforts, it considered completed Job Files stored in its Walnut Creek engineering library, also called the Walnut Creek Records Office, to be the official files. (CPSD DR 51, A 5, p. 2)

516. On February 15, 2012, PG&E stated that, prior to its MAOP validation review efforts, the records filed in its Walnut Creek Records Office and subjected to document control procedures were its master files. (CPSD DR 51, A 5, p. 2)

517. On February 15, 2012, PG&E stated that "A copy of the documents in the Job Package is maintained in the master Job File." (CPSD DR 51, A 5, p. 2)

518. As of February 15, 2012, PG&E's official files in its Walnut Creek Office did not contain a complete, consistent and comprehensive set of pipeline related job folders. (Ex.6, p. 6-75; PG CPSD DR 48, A 1)

519. As part of its post San Bruno, MAOP Records Validation Project, PG&E accumulated a set of more than 132,000 job folders that it provided CPSD on February 15, 2012, of which 63.3% were from its Bayshore facility, only 30.3%

were from Walnut Creek, and the remaining 6.4% were distributed across 42 other PG&E locations. (CPSD DR 48, A 1, Atch1)

520. One product of that MAOP Validation process will be comprehensive Pipeline Features Lists that identify item-by-item the pipes, valves and other pipeline assets that comprise each pipeline located in an HCA, including Line 132. PG&E expects to complete Pipeline Features Lists for all non-HCA transmission pipelines in 2013. (CPSD DR 41 A 11)

521. Commonly, multiple duplicate versions of the same job folder or document were stored in one or more locations and across Gas Transmission Records, Division Offices, Engineering, Construction and Billing. (CPSD DR 51 A5, Ex. 6, pp. 6-40 and 6-41)

522. As of February 2012, and prior to completion of the MAOP project, PG&E had:

a. 12,446 jobs with their job folders stored across 2 locations,
b. 1711 jobs with their job folders stored across 3 locations,
c. 293 jobs with their job folders stored across 4 locations,
d. 8 jobs with their job folders stored across 6 locations,
e. 4 jobs with their job folders stored across 7 locations, and
f. 1 job with its job folders stored across 10 locations.

(Ex. 6, p. 6-64; CPSD DR 48, A1. (February, 2012))

523. As of December 2011, PG&E was unable to identify exactly how many duplicate Job Files or job folders it had. (Ex. 6, p. 6-61; CPSD DR 25, A1 (December 19, 2011))

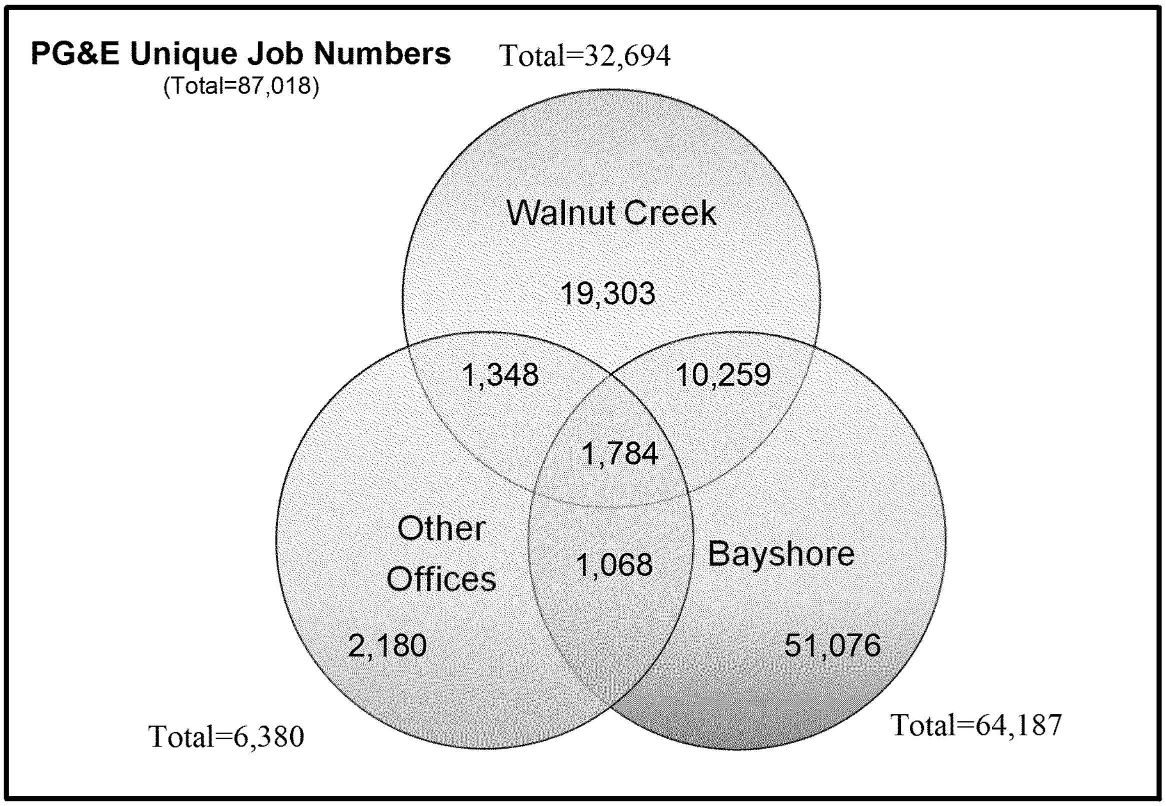
524. At the time PG&E began its MAOP validation effort, PG&E did not know how many total jobs or job folders it had, (Ex. 6, p. 6-53) nor did PG&E know how many job folders it had stored in each of its local sites. (CPSD DR 25, A1)

525. As of December 2011, PG&E could not provide an estimate of the number of job folders located outside of its Emeryville facility because the MAOP Validation and Verification Project was still underway. (CPSD Ex. 6, p. 6-71.)

526. More than one year after PG&E began its MAOP Records Validation Project it still had approximately 875 boxes in Emeryville containing an unknown number of job folders to be processed and inventoried. (CPSD DR 25, A1)

527. In February 2012, PG&E's Emeryville data catalog showed 146,227 job folder records relating to 87,018unique job numbers. (Ex. 6, p. 6-70)

528. As of February 2012, out of the 87,018 unique job numbers defined in PG&E's Emeryville Data Catalog, the following Venn Diagram shows where each of the job folders was originally stored.



a. 51,076 (58.7%) jobs were stored in Bayshore only.
b. 19,303 (22.2%) jobs were stored in Walnut Creek only.
c. 10,259 (11.8%) jobs were stored in Walnut Creek and Bayshore.
d. 2180 (2.5%) jobs were stored in other offices only (not in Walnut Creek or Bayshore or both).
e. 1784 (2.1%) jobs were stored in Walnut Creek, Bayshore and at least one other office.

f. 1348 (1.5%) jobs were stored in Walnut Creek and at least one other office (excluding Bayshore).

g. 1068 (1.2%) jobs were stored in Bayshore and at least one other office (excluding Walnut Creek).

(Exhibit 2, p. 6-63)

529. PG&E has job folders that contain documents, but that are allocated to an incorrect job number. (Ex. 6, p. 6-71)

530. Prior to August 2010, PG&E did not have a complete and comprehensive master index of pipeline related Job Files or of job folders associated with each job. (Ex.6, pp. 6-42, 6-56, 6-53, 6-41, 6-55, 6-69, 6-79 and 6-49; CPSD DR 25, A1, p. 10 (December 19, 2011))

531. Reliable, traceable, verifiable and complete records are necessary for PG&E to promote the safety of its gas transmission system. (CPSD Ex. 8, p. 16 of 72.

532. "On January 10, 2011, PHMSA issued Advisory Bulletin 11–01.1 This Advisory Bulletin reminded operators that if they are relying on the review of design, construction, inspection, testing and other related data to establish MAOP and MOP, they must ensure that the records used are reliable, traceable, verifiable, and complete." (Federal Register / Vol. 77, No. 88 / Monday, May 7, 2012, 26822.)

533. "PHMSA and federal regulations recognize that requirements as of January 2011 to keep traceable, verifiable and complete records were reminders to natural gas pipeline transmission operators." (Duller/North Supp Data Response to PG&E DR 6 Q 4)

534. Prior to the San Bruno disaster, PG&E did not have electronic access to the job start dates for projects earlier than 1996. (CPSD Ex. 6, p. 6-49; CPSD DR 25 A 1).

535. Before the San Bruno incident, PG&E did not have a control system in place to monitor the location of all of their job folders, or the location of job folders for any given job. (CPSD Ex. 8, p. 38 of 72.)

536. Before the San Bruno incident, no "master" index existed to steer safety engineers to the proper files to review. (CPSD Ex. 8, p. 38 of 72.)

537. Prior to the San Bruno disaster, PG&E had to manually extract job start dates from its microfiche collection of job folders for jobs starting between 1983 and 1996. (CPSD Ex. 6, p. 6-49; CPSD DR 25 A 1)

538. Prior to the San Bruno disaster, PG&E had to manually review the relevant job folders for jobs with start dates prior to 1983. (Ex. 6, p. 6-49; CPSD DR 025, A1, p. 10 (December 19, 2011))

539. As of September 2010, PG&E' Gas Transmission Division managed its physical and electronic records using multiple systems that were not well integrated, and contained duplicate information. (Ex. 6, p. 6-79; CPSD 25 A 2(i))

540. PG&E states that it performed a 2008 internal audit of electronic data management practices and found several issues regarding retention, however, PG&E has not shown that it acted upon these audit results. (CPSD Ex. 8, pp. 33 of 72 and 34 of 72.)

541. Prior to 2010, each of PG&E's job folders lacked a definitive pipeline features list that could be used as a checklist to determine the presence or absence of key document types. (Ex. 6, p. 6-43)

542. Prior to 2010, PG&E used both FoxPro and Filemaker to track some of the physical boxes and folder of gas transmission records, but neither tracking system had comprehensive indexes or catalogs. (Ex. 6, p. 6-53)

543. Before the San Bruno pipeline rupture and gas fire, there was no single, central document storage facility that held a complete and comprehensive collection of all pipeline-related Job Files and folders. (CPSD Ex. 6, p. 6-69.)

544. Both the lack of any form of central index and the number of different office locations where job folder records were stored were major barriers to efficient retrieval of pipeline records. (CPSD Ex. 6, p. 6-69.)

545. The absence of a central index or records catalog meant that it was not clear what pipeline-related documentation was held, where or by whom, or more importantly, where the master set of documentation was held. (CPSD Ex. 6, p. 6-69.)

546. On August 17, 2012, PG&E identified approximately 107,700 boxes of records it had transferred to the Iron Mountain storage facility and stated that the records might pertain to some or all of 15,045 unique job numbers PG&E had previously identified by PG&E on July 10, 2012. (CPSD DR 84, A1)

547. As of August 2012, PG&E stated it had recently identified an additional 15,045 Job numbers within the 107,700 boxes that had been transferred to Iron Mountain following the Cow Palace review. (CPSD Ex. 8, p. 59 of 72.)

548. As of August 29, 2012, of the 15,045 additional unique job numbers identified by PG&E on July 10, 2012, 2,149 of these job numbers were not located in the ECTS database and fell into the following groups. (CPSD DR 85, p. 3)

a. 711 of the job numbers were jobs that were not located during the MAOP field office retrieval efforts and could potentially be located in Iron Mountain.
b. 1,165 of the job numbers had erroneous values that were not job numbers.
c. 61 of the job numbers were not job numbers at all, but rather, Project Status Reporting System identification numbers that correlated to actual job numbers.
d. 162 of the job numbers were recently completed jobs which would therefore not be at Iron Mountain or in ECTS.
e. 50 of the job numbers were jobs constructed using a different numbering system that had been linked to current job numbers in ECTS.

549. The count of job file numbers reported to CPSD exceeds the total number of Job Files associated with particular projects. (Supp. to CPSD DR 25, A1, January 31, 2012)

550. PG&E's lack of standardization and consistency in its numbering system has served as a barrier to information retrieval. (Ex. 6, p. 6-58)

551. PG&E has failed to maintain a definitive, complete and readily accessible database of all gas leaks for its pipeline system because it has failed to routinely migrate all historical leak information from management system to management system. (CPSD Ex. 6, p. 6-88, CPSD Ex. 7, p. 5 of 5)

552. PG&E maintained leak and leak repair data collected from 1970 to 1999 in its Mainframe Leaks system. (CPSD DR 69, A6)

553. In 1999, PG&E developed a new leak and repair tracking database called the Integrated Gas Information System (IGIS). (PG&E Ex. 61 p. 3-61)

554. PG&E did not migrate approximately one million (1,000,000) leak records from its Mainframe Leaks system into IGIS. (CPSD DR 69, A6)

555. PG&E maintained a subset of leak information from its Mainframe Leaks system in another system it called “PC Leaks System.” (CPSD DR 69, A6)

556. When PG&E adopted the IGIS application, it decided to migrate data only from its PC Leaks system, but not from its Mainframe Leaks system. (CPSD DR 69, A6)

557. PG&E is unable to locate any internal documents or memos to explain or justify why certain information was not migrated to IGIS. (CPSD DR 69, A6)

558. PG&E’s “System Active Grading” report encouraged downgrading leaks instead of making repairs. (CPSD DR 69 A2, Atch 1)

559. PG&E’s 1985 and 1995 Gas Pipeline Replacement Programs and records failed to include Lines 132 and 151 for replacement because PG&E had incorrectly classified the weld/joint types. (CPSD DR, Q 1(a) Atch 32)

560. In 2007 PG&E was informed that in 1995 it had selected the wrong year as the upper limit for its Gas Pipeline Replacement Program (1947 rather than 1948), therefore, both lines 132 and 151 were excluded from the program. (CPSD Ex. 6, p. 6-50, CPSD Ex. 7, p. 4 of 5)

561. In 1992, Federal Emergency Management Agency (FEMA) issued a report on the earthquake resistant construction of gas and liquid pipeline systems, noting that,

"Older pipelines, including welded pipelines built before 1950 in accordance with quality control standards less stringent than those used currently, as well as segmented case iron pipelines, have been severely damaged."(FEMA Report). (CPSD Ex. 6, p. 6-91); http://www.fema.gov/library/file?type=publishedFile&file=fema-233.pdf&fileid=e5633860-1e55-11db-b486-000bdba87d5b.

562. PG&E's lack of necessary accurate and readily locatable gas transmission line records meant that it has been unable to precisely identify which of its pipelines were more prone to extensive damage during some earthquakes and thereby ensure safe pipeline operation. (CPSD Ex. 6, p. 6-91, CPSD Ex. 7, p. 5 of 5)

563. Accurate, comprehensive and quickly accessible records are essential in order for PG&E to identify similar kinds of pipelines to those identified by FEMA as earthquake prone. (CPSD Ex. 6, p. 6-92)

VII. Description of PG&E's SCADA system and Gas Control Work at the Milpitas Terminal

564. (p.71) PG&E's gas SCADA system is one of the largest in the U.S., providing remote control of 6,438 miles of transmission pipeline. Parts of PG&E's 42,141 miles of gas distribution pipeline are also monitored by SCADA. About 9,000 sensors and devices are installed along the length of the pipelines to enable the display of flow rates, equipment status, valve position status, pressure set points, and pressure control among other data. The current generation of SCADA used by PG&E is based on Citect software from Schneider Electric.

565. (p.72) The entire pipeline is controlled and managed from the Primary Gas Control Center located in San Francisco. An alternate control center is located in Brentwood. Several compressor stations and local control stations such as the Milpitas Terminal are situated along the pipelines, each with a separate local control system. Although PG&E excludes separate local control systems from the SCADA system, for the purpose of this report the local control systems are included and considered to be a part of the entire SCADA system.

566. (p.72) PG&E's SCADA system is separate from its GIS. The GIS data is displayed on separate computer screens at each of the operator consoles at both the primary and alternate gas control centers.

567. (p.73) The PG&E SCADA system is programmed to register alarms when the pressure exceeds the MAOP or if the value is less than a preset low level. It does not provide automatic control or intelligent alarming functions such as high rate of change alarms. The operational decisions are made by PG&E Gas Operators in charge of the five consoles at the Gas Control Center.

568. (p.74) Monitor valves act as limiting devices to protect against accidental overpressure for the outgoing gas pipelines. Regulator valve set points for outgoing lines can either be manually set at Milpitas Terminal or remotely set through SCADA by PG&E Gas Control.

569. (p.75) Each of the incoming pipelines to Milpitas Terminal has a regulating valve and a monitor valve to limit the pressure within the terminal. Pressure is further reduced with a second regulating valve and a monitor valve for overpressure protection before it is sent through the outgoing lines. The monitor valves are normally left fully open. When the downstream pressure starts to increase and exceed a pressure set point, the monitor valve moves to control the downstream pressure.

570. (p.78) PG&E's gas control system consists of Programmable Logic Controllers (PLCs), pressure controllers and related instrumentation which communicate with the SCADA computers in San Francisco. Redundant PLCs are provided with a fail-over switch so if one fails the other will pick up. The PLCs communicate with the 26 pressure controllers over a local Ethernet network. The PLCs execute a large program that calculates the flows and processes the inputs from many valve position sensors. The PLCs manage communication with the 26 pressure controllers and generates controller error alarms should a controller fail or lose communication. The PLCs also communicate commands issued by the Gas Operators located at Gas Control Center in San Francisco to control valves and to

change pressure set points. Communication between the PLC software and the equipment is transmitted over individual wires connected to the PLC Input/Output (I/O) devices (also referred to as Genius Blocks).

571. (p.79) At Milpitas Terminal, all of the pressure instruments have a full scale range of 0 to 800 psig. The pipeline at Milpitas Terminal is rated up to 720 psig, therefore no pressure greater than 800 psig should ever occur.

572. (p.80) PG&E installed an Uninterruptible Power Supply (UPS) at Milpitas Terminal to power the SCADA and control equipment for a short period of time during a line power outage and before the emergency generators start delivering power.

573. (p.81) In February 2010, PG&E asked a Contract Engineer to offer a proposal to investigate and provide recommendations for UPS/battery problems at Milpitas Terminal. In mid-March 2010, a Contract Work Authorization was approved for the Contract Engineer to perform the proposed work on the UPS at Milpitas Terminal.

574. (p.81) On March 31, 2010, the UPS at Milpitas Terminal failed, exposing the gas control system to a short interruption of power and potential loss of pressure control.

575. (p.81) The UPS at Milpitas Terminal had been in service since the 1980s with a three-phase system that was no longer needed and for which parts were no longer available. In 2010 PG&E decided to replace the entire UPS system with a new one.

576. (p.81) PG&E installed at Milpitas Terminal three mini-UPS units on April 1-2, 2010, to provide temporary power.

577. (p.82) PG&E Work Procedure (WP) 4100-10 governs system clearances in advance of work. A system clearance is required for work that affects gas flow, gas quality, or the ability to monitor the flow of gas. All system clearances require authorization from PG&E's Gas System Operations (GSO).

578. (p.82) The clearance documents must include the application for gas clearance, special instructions, sequence of operations, up-to-date and correct operating maps and diagrams, and any other drawing used to prepare for the clearance. New clearances require start and end times, dates, and a designated Clearance Supervisor. The clearance application must also completely describe the work to be performed.

579. (p.83) A clearance application for the UPS work at Milpitas Terminal was submitted on August 19, 2010, as Clearance Number MIL-10-09 and approved by PG&E Gas Control on August 27, 2010.

580. (p.83-84) MIL-10-09 marked the Clearance Supervisor as "TBD". The checkbox on MIL-10-09 which asks if normal function of the facility will be maintained was checked "No". However, there was no explanation provided on the clearance application as to how the work will affect normal function of Milpitas Terminal. Under the Sequence of Operations, MIL-10-09 did not list any specific operations or key communication steps to be reported to Gas Control. There is no record provided by PG&E showing the specific steps taken and the time, date, and initials of the person completing each step in the system clearance.

581. (p.86) On the afternoon of September 9, 2010, the Contract Engineer with assistance from the Gas Technician, Apprentice Gas Technician 1 and the Construction Lead were reconnecting all remaining circuits after completing their work.

582. (p.86) At 4:46pm the Gas Technician at Milpitas called Gas Operator 2 to let him know SCADA communication with Milpitas Terminal would be interrupted for a few minutes while they installed Mini-UPS unit 7.

583. (p.86) After the Contract Engineer and his team had transferred what they thought was the last circuit, they discovered an unidentified active circuit breaker remained in the UDP panel. The Contract Engineer switched it off and the mimic panel went dead.

584. (p.86) At that time, the system appeared to be operating normally. Alarm records show no activity from 5:09pm to 5:21pm. The crew working in Milpitas was getting ready to wrap up believing they had successfully completed the planned activities for the day.

585. (p.87) At 5:23pm, records of SCADA alarms and pressure readings indicate valves opening and pressure increasing. The pressure readings measured at flow meters M31, M32 and M38 on Lines 132, 101 and 109 respectively, increased from 370 psig to 380 psig in about 90 seconds.

586. (p.87) The alarms were likely cause by an intermittent short circuit on a piece of wire in the pressure feedback circuit in the Control System equipment enclosure which contains hundreds of wires. The short circuit started a cascade of failures in the gas pressure sensors and pressure controls which lasted for over 3 hours. The Contract Engineer and Construction Lead began disconnecting and reconnecting circuits to find where the shorted wires or other load on the 24 volt current loops. At about 8:40pm, they eliminated the short and all the instruments and controls then resumed normal operation. The shorted connection was at a terminal block near the PS-A and PS-B where wires were possibly jostled during connection of the mini-UPS.

587. (p.95) Because of the malfunctions at Milpitas, PG&E's Gas Operators in San Francisco lost the ability to monitor and control the valves at Milpitas Terminal with the SCADA system displaying inaccurate information. The Gas Technician at Milpitas began to manually apply valve pressure gauges to verify and report pressure readings and positions of regulating and monitoring valves to Gas Operators at Gas Control Center. The Gas Technician was instructed to manually close certain valves and lower monitor valve set points. About 40 minutes after pressures began rising in the gas discharge header at Milpitas Terminal, Line 132 ruptured.

588. (p.87) It was after 10:30pm when the Sr. Gas Engineer was able to restore operation to the three PLCs which had malfunctioned. Those units suffered a rare

type of malfunction and the manufacturer had to be contacted to advise how to correct it. PG&E did not determine if this malfunction was indicative of failing or defective units and they are still in service.

VIII. Post-Incident Drug and Alcohol Testing

589. (p.99) PG&E performed post-incident drug testing of three PG&E employees and a PG&E contractor working on the UPS Clearance at the Milpitas Terminal. The drug testing was administered by a third party independent laboratory on September 10, 2011 between 3:36am and 5:21am and all four individuals tested negative.

590. (p.99) The post-incident alcohol test of the same four individuals was performed on September 10, 2011 between 3:10am and 5:02am.

IX. Emergency Response

591. (p.102) PG&E first responders at the scene of the incident could not identify the cause of the fire.

592. (p.102) PG&E offered no specific training for its first responders on how to recognize the differences between fires of low-pressure natural gas, high-pressure natural gas, gasoline fuel, or jet fuel.

593. (p.102) PG&E's procedures did not assign its control room operators specific regions to monitor. Each operator decided which regions he or she preferred to look at, making duplicative efforts and neglect of certain regions possible. Duplicate and/or incorrect information to the Control Room, Dispatch, and others was repeatedly transmitted and acknowledged. PG&E did not notify emergency officials (call 911) upon recognition of a potential line rupture. The operating supervisor and control room operators had the authority to make the decision to dispatch crews to shut valves, yet no decision was made by either.

594. (p.102) PG&E took 95 minutes to isolate the rupture. The time for isolation could have been reduced had PG&E installed remote control valves (RCVs), automatic shut-off valves (ASVs), and/or appropriately spaced pressure and flow

transmitters throughout its system to allow them to quickly identify and isolate line breaks.

A. Line Break Recognition

a. By 6:18pm, Gas Operator 1 concluded there had been a rupture on a transmission line within a 12-mile corridor of the peninsula, but could not pinpoint its location.

b. As of 6:31pm, Gas Control and Dispatch were still discussing the "gas station" that had blown up, a recurring rumor at the time. The location of the "gas station", i.e. the incident location, had yet to be determined, and was to be determined by the dispatched GSR.

c. At around 6:51pm a gas control operator claimed, "it looks like it might [be transmission], if anything, distribution ".

d. At 6:53pm, the San Francisco T&R Supervisor communicated to Gas Control that he had crews responding, but they might be heading to Martin Station.

e. At around 7:20pm, the Senior Distribution Specialist told Dispatch that the incident was reportable. In a post-accident interview, he explained, "So, early on, people are running around saying, you know, they think it's a plane. So -- until we were completely sure, that's when I made the call."

f. PG&E did not close the remotely operated Martin Station valves on L-132 until 7:29pm.

B. Coordination with External Agencies

a. At 6:54pm, San Bruno Police called Dispatch indicating their need for gas personnel.

b. At 7:02pm, San Mateo County Sheriff inquired whether the power in the area had been shut off. They also asked PG&E if they knew about the plane crash.

c. At 7:59pm the first call to Dispatch from San Mateo County Fire Department came in. The message was to inform PG&E of their command post being set up at Lunardi's Market.

595. (p.108) At 6:12pm, SCADA showed the upstream pressure at Martin Station on L-132 had decreased from 361.4 psig to 289.9 psig. At 6:15pm, SCADA showed a low-low alarm at Martin Station that indicated a pressure of 144 psig on L-132. Per PG&E's procedure, members of Gas Control attempted to troubleshoot the alarms by examining the pressures and conditions at different stations.

596. (p.108) At 6:18pm, PG&E Dispatch was notified of a fire in San Bruno by an off duty PG&E employee who speculated a jet crash. The dispatcher responded that they would notify a supervisor.

597. (p.108) At 6:21pm, an off-duty GSR called into Dispatch alerting them that there was a fire in San Bruno that appeared to be gas fed. The dispatcher responded that he would send a GSR out to investigate.

598. (p.108) At 6:23pm, the Senior Distribution Specialist called Dispatch, reporting that he was heading to the reported explosion. At about the same time, Dispatch called a GSR working in the San Bruno area and instructed him to go to Sneath and Skyline in San Bruno to investigate the reported explosion.

599. (p.108) At 6:25pm, Dispatch called the Peninsula On-Call Supervisor to give him a heads up about the incident. He responded, "I'm probably on my way."

600. (p.108) At 6:27pm, while Gas Operators 1 and 2 were still in the process of determining the cause of the alarm, Dispatch called Gas Operator 3 to inquire if they noticed a loss of pressure in San Bruno. Dispatch advised about large flames and that a GSR and a Supervisor were heading to the scene. Gas Operator 3 responded that they had not received any calls yet.

601. (p.109) At 6:28pm, the Gas Controllers discussed the low-low pressure alarms amongst themselves and associated the reports of the fire at San Bruno with the pressure drop at Martin Station. At 6:29pm, a Gas Controller had mentioned to a

caller that pressure on L-132 had dropped from 396 psig to 56 psig and that "we have a line break in San Bruno… while we have Milpitas going down."

602. (p.109) At 6:30pm, Dispatch called the GSR to check on his status. The GSR was still in traffic at the time. The Measurement and Control (M&C) Superintendent of the Bay Area, who claimed to be on-call 24/7 to respond to any gas event within his area, arrived at the rupture site just after 6:30pm after seeing it on the news.

603. (p.109) At 6:31pm, Gas Operator 1 called Dispatch regarding the previous inquiry about the loss of pressure and speculated that PG&E's gas facilities may be involved in the incident. Dispatch responded to Gas Control that a radio news report claimed the fire was due to a gasoline station explosion.

604. (p.109) At 6:32pm, Gas Control left a message for San Francisco Transmission and Regulation Supervisor about the low-low alarm at Martin Station, and the possibility of a leak.

605. (p.109) At 6:35pm, the M&C Superintendent of the Bay Area called Gas Control to inquire about the fire and told them to call the superintendent of the region. He then proceeded to the incident site. At about the same time, Mechanic 1 called Dispatch, saying that PG&E's transmission line ran through the scene of the fire and that the flame was consistent with ignited gas from a transmission line. As Mechanic 1 headed to the Colma yard (Yard), he was called by Mechanic 2, who was then told to head to the Yard.

606. (p.110) At 6:36pm, the San Francisco T&R Supervisor returned the Gas Control's call and told them to contact the Peninsula Division T&R Supervisor. The gas controllers had been coordinating with the Sr. Gas Coordinator to make the appropriate contacts.

607. (p.110) At 6:40pm, after confirming the involvement of PG&E's facilities with Dispatch and Gas Control, the Peninsula On-Call Supervisor called M&C Mechanics 1 and 2 and told them to "get to the yard, get their vehicles and head in that direction (of the valves)."

608. (p.110) At 6:41pm, the GSR and the Senior Distribution Specialist were at the scene of the incident and reported to Dispatch that the fire department did not yet know the cause of the flames. The GSR made Dispatch aware that there were gas transmission lines in the area. Dispatch conveyed to the GSR that a jet might have struck a gasoline station which in turn caused the gas line to blow with it. The GSR called the Gas Service On-Call Supervisor, and the Gas Service Night Supervisor, to let them know he was on site. The Gas Service Night Supervisor arrived on site later.

609. (p.110) At 6:48pm, the Senior Distribution Specialist told Dispatch, "We've got a plane crash" and "we need a couple of gas crews and electric crews." Dispatch acknowledged the request.

610. (p.110) Mechanic 1 arrived at the Yard at 6:50pm. Mechanic 2 arrived soon after. More internal contacts ensued. At 6:51pm, a Gas Control Operator claimed, "it looks like it might [be transmission], if anything, distribution."

611. (p.110) At 6:53pm, the San Francisco Division T&R Supervisor communicated to Gas Control that he had crews responding, but they might be heading to Martin Station. At 6:54pm, San Bruno Police called Dispatch requesting gas support. Dispatch replied, "We know, they're out there already." Dispatch then told the Troublemen Supervisor about a plane that had crashed into a gas station, and asked for gas and electric utilities in the area to be turned off. The Troublemen Supervisor replied that he was notifying troublemen.

612. (p.110) At 6:57pm, PG&E's Operations Emergency Center (OEC) was opened. While watching the news on a television at the Yard, Mechanic 1 identified the location of the incident site and the nearest valves to be shut to cut off fuel to the fire.

613. At 7:02pm, the San Mateo County Sheriff asked Dispatch if they were aware of the plane crash; Dispatch responded, "I'll go ahead and relay that message". At around the same time, Mechanic 1 called Dispatch and notified them of his plan to shut valves to isolate the rupture.

614. (p.111) At 7:06pm, Mechanic 1 called the Peninsula Division T&R Supervisor for authorization to shut the valves. The Peninsula Division T&R Supervisor approved. Mechanics 1 and 2 proceeded to the first valve location (containing valve V-39.49). Gas Control was continuously making and receiving calls to gather and relay information.

615. (p.111) At around 7:07pm, a Gas Control Operator mentioned that the M&C Superintendent of the Bay Area was on site but couldn't get close enough to the actual location itself because of the extent of the fire and that "until the crew arrives, secures it and comes up with a plan, we're just going to continue to feed it."

616. (p.111) At 7:12pm, the Troublemen Supervisor told Dispatch about his plan to order a mandatory call out requiring all Colma Yard employees to report in.

617. (p.111) At 7:15pm, a Gas Control operator was noted saying, "The fire is so big I guess they can't determine anything right now." At approximately 7:15pm, an FAA representative informed the M&C Superintendent of the Bay Area that there was no plane involved in the incident.

618. (p.111) At 7:16pm, Dispatch began to relay the Troublemen Supervisor's plan. Minutes later, the M&C Superintendent of the Bay Area instructed the Senior Distribution Specialist, who was with him at the time, to call Gas Control and tell them the fire was gas related and to declare it a reportable incident.

619. (p.112) Mechanics 1 and 2 arrived at the first valve location at 7:20pm. At 7:22pm, the Senior Distribution Specialist contacted Dispatch and said that while unconfirmed, it looked like gas was involved. At 7:22pm, Gas Control told the Senior Vice President that the incident was likely to be an L-132 break although nothing had been confirmed. At 7:25pm, Dispatch informed Gas Control that the M&C Superintendent of the Bay Area was on scene and confirmed that the incident was a reportable gas fire. Gas Control confirmed that L-132 was the involved line. At 7:27pm, the SF Division T&R Supervisor requested that Gas

Control lower the pressure set points as low as possible at Martin Station to isolate L-132 from the north.

620. (p.112) At 7:29pm, Gas Control remotely closed the involved L-132 valves at Martin Station to cut off the feed of gas north of the rupture. By 7:46pm, Mechanics 1 and 2 had traveled north of the rupture and closed valves V-40.05 and V-40.05-2 at Healy Station to isolate the rupture.

X. Safety Culture

621. (p.131) Over the period 1997 to 2010, PG&E spent 4.9% (a total of $39 million) less than the Commission authorized for pipeline transmission operations and maintenance,

622. (p.131) PG&E cannot identify any PG&E requests for the recovery of costs for safety improvements to the natural gas transmission pipeline system that were denied by the Commission.

623. (p.132) Over the past 15 years PG&E has focused on decreasing operational costs.

624. (p.133) Between 1999 and 2010, gas transmission and storage revenues were $430 million higher than the amounts needed to earn the authorized return on equity.

625. (p.133) Between 1999 and 2010, PG&E's actual revenues exceeded authorized revenue requirements by $224 million.

626. (p.133) Between 2001 and 2010, actual functional operations and maintenance expenditures were $43 million lower than adopted.

627. (p.133) Capital expenditures were $94 million lower than adopted between 1997 and 2000.

628. (p.133) Gas transmission and storage rates were not reduced in 2008 through 2010 to reflect the federal bonus tax depreciation adopted as part of the federal economic stimulus measures.

629. (p.133) The adopted rate base exceeded the actual rate base by an average of $67 million per year during 1998 to 2010.

630. (p.134) As of 2010, approximately 17% of PG&E's overall pipeline transmission system could accommodate ILI tools and slightly more than 21% of its transmission pipeline system located in high-consequence areas could be inspected using ILI tools. At the same time, about 50% of the combined Sempra Energy utilities' natural gas transmission pipelines could accommodate ILI tools, and approximately 80% of Southern California Gas Company's transmission pipeline located in high-consequence areas has been inspected using ILI tools.

631. (p.134) PG&E changed assessment methods for some projects from in-line inspections to ECDA to reduce costs.

632. (p.135) PG&E deferred some integrity management expense projects to future years.

633. (p.135) PG&E changed the definition of the pipelines covered by integrity management rules in 2010 to reduce the scope of the integrity management program.

634. (p.135) PG&E's 2009 Investor Conference presentation included a slide on "Expenditures," which showed decreasing investments in gas transmission infrastructure; from $250 million in 2009 to $200 million in 2010.

635. (p.135) On February 16, 2005, the Chairman of the Board, Chief Executive Officer and President (CEO) presented the idea of Transformation to the boards of directors, a company-wide business and cultural transformation campaign to reduce operating costs and instill a change in its corporate culture. As stated in the 2006 Annual Report, the reason for the investment in Transformation was, "If the actual cost savings are greater than anticipated, such benefits would accrue to shareholders."

636. (p.137) PG&E reduced its revenue requirements by $41 million in 2008 and another $56 million in 2009. PG&E under-spent its adopted functional

operations and maintenance amount by $2.9 million in 2006, $2.2 million in 2007, and $3.5 million in 2008.

637. (p.138) 2008 presentations from PG&E leadership highlight that PG&E had a plan to "Deliver on its Financial Objectives." The presentations did not mention Transformation.

638. (p.139) PG&E Company's 2009 Annual Report discloses that the utility accrued $38 million, after-tax, of severance costs related to the elimination of approximately 2% of its workforce.

639. (p.139) PG&E stated the 2% workforce reduction equated to about 409 employees.

640. (p.140) PG&E's actual return on equity for gas transmission and storage operations averaged 14.2% during 1999 to 2010. PG&E's authorized return on equity averaged 11.2% over that period.

641. (p.140) PG&E Company authorized a cash dividend in 2005 of $476 million; in 2006, $494 million; in 2007, $547 million; in 2008, $589 million; and, in 2009, $624 million.

642. (p.141) PG&E's 2010 Annual Report stated that during each of 2008, 2009, and 2010, the utility paid $14 million of dividends on preferred stock. On December 15, 2010, the board declared a cash dividend on its outstanding series of preferred stock totaling $4 million that was paid on February 15, 2011.

643. (p.141) On December 15, 2004, PG&E's board authorized a purchase of shares of the company's issued and outstanding common stock with an aggregate purchase price not to exceed $1.8 billion, not later than December 31, 2006. By June 15, 2005, the company projected that it may be able to repurchase additional shares of common stock through the end of 2006 in an aggregate amount of $500 million and, as such, increased the amount of the common stock repurchase authorization for a total authorization of $2.3 billion.

644. (p.142) The 2010 Annual Report notes that $57 million was provided in each year of 2008 and 2009, and $56 million was provided in 2010 to PG&E Corporation employees and non-employee directors.

645. (p.142) PG&E provides a Short-term Incentive Plan, a "Pay-for-Performance" bonus, and a Reward and Recognition Program.

646. PG&E's inadequate record keeping has interfered with the regulatory process.

a. PG&E has been unable to produce documents requested by the Commission in a timely fashion. (CCSF Testimony I.11-02-016 at p. 10-11)

b. The Administrative Law Judge in Investigation 11-02-016 found "it is troubling that PG&E is apparently unable to respond to Legal Division's data requests in a timely manner. In this proceeding, PG&E has sought and been granted numerous extensions to provide responsive documents. While I recognize that the Commission and Legal Division have requested that PG&E provide a substantial amount of documents, many of these documents are required to be maintained under federal and state statutes and regulations. As such, it is unclear why PG&E is unable to provide these documents in a timely manner." (CCSF Testimony I.11-02-016 at p. 11)

c. In NTSB exhibit 2-AI, PG&E stated that spiked its lines to avoid assessing potential manufacturing and construction defects. It stated that it did so pursuant to Risk Management Instruction 06 (RMI-06). (CCSF Testimony I.11-02-016 at p. 13)

d. In NTSB Exhibit 2-AG, PG&E provided a document titled "Risk Management Instruction, (RMI-06 Rev. 1)." This document was placed in the record of the NTSB proceeding on February 5, 2011. (CCSF Testimony I.11-02-016 at p. 13)

e. The RMI-06 provided in Exhibit 2-AG includes a statement that "[t]o keep from continually losing operating pressure on pipelines that have a potential long seam manufacturing threat, PG&E has made a decision to only reprioritize those pipeline segments that exceed the historic 5 year MOP plus 10% of the historic 5 year MOP." (Exhibit 2-AG, p. 2). (CCSF Testimony I.11-02-016 at p. 14)

f. The NTSB conducted hearings into the San Bruno explosion and fire from March 1-3, 2011. During the hearings, PG&E was questioned about its assessment of manufacturing defects. (CCSF Testimony I.11-02-016 at p. 14)

g. On April 6, 2011, PG&E sent a letter to the NTSB stating "We have recently discovered that the version of PG&E's RMI-06 which PG&E submitted to the NTSB and became NTSB Exhibit No. 2-AG included the cover sheet approval for RMI-06 revision 0 but attached the text for RMI-06 draft revision 1." (NTSB Revised Exhibit 2-AG, p. 2.) (CCSF Testimony I.11-02-016 at p. 14)

h. The April 6, 2011 letter also stated "We have not identified a cover sheet approval for this RMI-06 revision 1, and we have no indication that it was ever approved," but that "The approved RMI-06 (Rev. 0) at the time of our original submission is enclosed along with the currently-effective RMI-06 (Rev. 1). Neither of them includes the 10 percent provision found in the unapproved version." (NTSB Revised Exhibit 2-AG, p. 2.). (CCSF Testimony I.11-02-016 at p. 14)

i. In the Joint Evidentiary hearings, CPSD produced Joint Exhibit 9. This exhibit is an April 12, 2010 PG&E memorandum to File with the subject "MOP + 10% Allowance."

i. The memorandum admits that "currently, CFR Title 49, Part 192.917(e)(3) (12/15/2003) does not specify any allowance past MOP for ERW pipe."

ii. The memorandum states that "although PHMSA FAQs further states (sic) that 'any pressure increase, regardless of amount' will require assessment, PG&E will interpret than an allowance of MOP + 10% is suitable before the pipeline with a manufacturing seam threat is assessed."

iii. The memorandum cites 49 CFR § 192.201 .

iv. This section has no applicability to the Transmission Integrity Management rules governing the stability of potential manufacturing and construction defects.

Class Location OII – Stipulations of Fact

647. PG&E misclassified 140 miles (898 segments) by classifying these segments below their actual class location designation due to PG&E's admitted errors in its Geographical Information System (GIS).

648. PG&E operated 224 segments of its transmission pipeline system operating at hoop stress of 40% above MAOP.

649. PG&E assumed SMYS values above 24,000 psi.

650. PG&E failed to patrol 120.6 miles of pipeline and an additional 51.5 miles of pipeline that it contends it patrolled but has no records of.

651. PG&E failed to provide "continuing surveillance" on at least 140 miles (898 segments) of transmission pipeline operating at greater than 20% SMYS that went up in class due to PG&E's admitted GIS errors.

652. 544 miles (2,837 segments) of its gas transmission pipelines changed in class location. PG&E April 2, 2012 update to its Response to the Order Instituting Investigation p.1.

653. 159 miles (1,192 segments) of its gas transmission pipelines went up in class. PG&E April 2, 2012 update to its Response to the Order Instituting Investigation p.1.

654. 9.1 miles (57 segments) of its gas transmission pipelines had a MAOP inappropriate for their current class location, including 2.8 miles that did not go up in class. PG&E April 2, 2012 update to its Response to the Order Instituting Investigation p. 1.

655. As part of its continuing review of class locations, PG&E has now determined that it cannot confirm that all transmission lines were patrolled as required by PG&E procedures. PG&E April 2, 2012 update to its Response to the Order Instituting Investigation p. 7.

656. PG&E's review has found that this procedure has not been followed by all local offices, and, as a result, some segments of transmission pipeline may not have been patrolled. PG&E April 2, 2012 update to its Response to the Order Instituting Investigation p. 7.