Appendix A: Findings of Fact

I. GENERAL

1. PG&E's witness admits that testimony on industry practices is irrelevant to the inquiry of whether an operator complied with the applicable safety laws. Joint RT 715:8-17 (Zurcher/CCSF).

2. As Mr. Zurcher characterized it, for natural gas operators, "Compliance with the regulations is the price of admission." Joint RT 752:2-3 (Zurcher/CCSF).

3. As a general principle, where aspects of gas operations create uncertainty, the operator must take steps to ensure the safe and reasonable operations of its system. Ex CCSF-1 at pp. 2-3.

II. PG&E'S TIMP

4. The Independent Review Panel found that "PG&E was not identifying all threats, as required by regulation; is not identifying segments of highest risk and remediating significant anomalies; and hence is not taking programmatic actions to prevent or mitigate threats." Independent Panel Report at p. 8.

5. The NTSB found that "the PG&E gas transmission integrity management program was deficient and ineffective." Ex CPSD-9 (NTSB Pipeline Accident Report) at p. 125 (Finding 19).

6. The NTSB made three recommendations to PG&E. These three recommendations were to: (1) revise its risk model to reflect PG&E's actual recent experience data on leaks, failures and incidents, (2) consider all defect and leak data for the life of the pipeline, including risk analysis for similar or related segments, and (3) revise its risk analysis methodology to ensure that the proper assessment methods are selected for all applicable integrity threats, with particular emphasis on design/material and construction threats. Ex CPSD-9 at p. 114.

A. Data Gathering

7. Eight months after the NTSB requested to provide all leak and repair information for Line 132, PG&E produced a 1988 an inspection report stating that Line 132 had experienced a longitudinal seam leak at mile post 30.44, approximately 8.78 miles south of the rupture. Ex CPSD-9 at p. 38. fn 61.

8. The segment identified in the memorandum was 0.375 inch wall thickness, X52, 30" DSAW pipe, installed in 1948. Ex. CCSF-1 (Exhibit 2 to Testimony of John Gawronski: 1989 TES Memorandum).

9. This report included a March 1, 1989 memorandum from PG&E's Technological and Ecological Services stating that a 30" section of Line 132 had been "removed for failure analysis because of a pinhole leak in the longitudinal seam weld." Ex. CCSF-1 (Exhibit 2 to Testimony of John Gawronski: 1989 TES Memorandum).

10. The memorandum also states that "the cracks are pre-service defects, i.e. they are from the original manufacturing of the pipe joint." *Id.*

11. PG&E replaced the segment upon discovering the leak in the longitudinal seam. Joint RT 885:19-886:2 (Zurcher/CCSF)

12. 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, at p. 567:23-27 (Harrison/CCSF).

13. PG&E's testimony concedes that it did not consider this report in its TIMP. PG&E-1c at p. 4-15 ("Even if our data gathering process had located records following the 1988 leak…") (emphasis added)

14. The NTSB found that "until May 6, 2011, the PG&E GIS had listed the cause of the leak as 'unknown.'" Ex CPSD-1 at p. 38.

15. Following the discovery of the memorandum, PG&E updated its database to indicate the pipe had been replaced due to a longitudinal defect. *Id.*

16. PG&E did not consider radiography records of girth from the 1948 construction of Line 132 indicating longitudinal seam defects. Ex CPSD-9 at p. 110-111.

17. The NTSB found that "because only 10 percent of the welds were radiographed as part of the 1948 construction, and those radiographs captured only a few inches of each longitudinal seam weld, less than 0.2 percent of the longitudinal seams on pipe segments installed in 1948 were radiographed. In light of the fact that five rejectable defects were found in the small percentage of longitudinal seam welds that were so examined, it is probable that additional longitudinal seam weld defects have remained in service since 1948." *Id.* (emphasis added).

18. The 1948 and 1989 memoranda demonstrate that PG&E should have been aware of both potential manufacturing and construction defects present on Line 132. Ex CCSF-1 at p. 6.

19. When asked whether he knew if PG&E has considered these weld reports, PG&E witness Zurcher conceded that he does not know if PG&E considered these reports. Joint RT 779:17-21 (Zurcher/CCSF)).

20. Instead, Mr. Zurcher asserted that the 1948 and 1988 weld reports were irrelevant to PG&E's TIMP. Joint RT 779:22-28 (Zurcher/CCSF)).

21. CCSF witness Gawronski reviewed additional PG&E records of pipe seam inspection and welding defects. Ex CCSF-1 at p. 10.

22. These documents confirm the existence of manufacturing and construction defects on steel transmission lines over 50 years old in PG&E's service territory. Ex CCSF-1 at pp. 10-11.

23. First, there are laboratory test reports from 1975 discussing brittle failure on four unidentified segments of Line 101 constructed with oxyacetylene welds, and two unidentified segments of Line 109 constructed with arc welds. Ex CCSF-1 (1975 PG&E Lab Test Report (Exhibit 6)).

24. For the segments removed from Line 101, the 1975 reports notes "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." *Id.*, at p. 16.

25. 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." *Id.*, at p. 17.

26. There are even earlier reports discussing issues with oxy-acetylene welds on Line 109. In 1965, PG&E issued an evaluation of an oxyacetylene weld from Main #109, San Francisco. CCSF-1 (Exhibit 7 to Testimony of John Gawronski: 1965 PG&E Evaluation of Oxy-Acetylene Weld From Main #109 San Francisco) at p. 1.

27. 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. *Id.* at p. 1.

28. PG&E agrees that "these welding techniques are obsolete methods of fabricating larger diameter transmission pipeline girth welds." Ex. Joint-34 (PG&E Response to Data Request CCSF_001-Q05).

29. In a metallurgical report, PG&E found evidence of cracking in its girth welds from 2 spools removed from Line 109. CCSF-1 (Exhibit 8 to Testimony of John Gawronski: 1996 Metallurgical Evaluation of Cracking in Line 109 Seam Welds) at p. 1.

30. Although the report did not identify which segments the sections of pipe were removed from, it states "the spools are believed to be from gas transmission line 109 which was installed in 1935." *Id.*

31. One of the cracks was found to be 76.5% of the wall thickness. *Id.*, at p. 2.

32. Using in-pipe remote video inspection of 22-inch line 109 gas pipe along Miranda Avenue, Palo Alto, another report found "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-1 (Exhibit 9 to Testimony of John Gawronski: 1996 In-Pipe Remote Video Inspection of Long Seam Welds 22-Inch Line 109 Gas Pipe, Miranda Avenue, Palo Alto) at p. 2.

33. PG&E was unable to provide any documentation demonstrating that these reports were considered as part of PG&E's TIMP. Ex. Joint-34 (PG&E Response to Data Request CCSF_001-Q05).

34. PG&E's witnesses were unable to provide any evidence that PG&E considered these reports in its TIMP. Ex Joint 34 (PG&E Response to Data Request CCSF 001-Q05 in I.12.01-007 ("Mr. Zurcher has no personal basis for a conclusion as to whether PG&E was or was not aware of the referenced reports at the time it developed its TIMP.").

B. Threat Identification

35. As part of its TIMP, an operator's threat identification needs to be proactive and investigative in nature. Ex CCSF-1 at p. 3.

36. Operators must address all other threats that stem from the unique characteristics of their pipeline system. *Id.*

37. In addition to considering the nine threat categories identified by the ASME B31.8S, operators need to address all other threats that stem from the unique characteristics of their pipeline system. *Id.*; Ex. Joint-28 (ASME B.31.8S) section 2.3.2.

38. In practice, if any additional threats are known, it is incumbent on the operator to identify and evaluate any threat to the integrity of the pipeline. Ex CCSF-1 at p. 3.

39. If a line is missing data specified in ASME B31.8S-2004, Appendix A, then the line must be assessed for that threat. CCSF-1 at p. 18.

40. 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. Joint -38 (ASME B.31.8S).

41. PG&E's Risk Management Procedure 06 (RMP-06) represents its Integrity Management Program as it existed on September 9, 2010. PG&E's Joint RT 1106:7-26 (Keas/CCSF).

42. Section 5.1 of RMP-06 "describes the tools and method selected to assess pipeline integrity and the process by which the assessment results are collected and integrated with other data." Ex PG&E-6 (Tab 4-6) at p. 39.

43. Section 5.5 of RMP-06 states that "the Company does not plan to use pressure testing to assess the integrity of its pipelines unless it is a post installation test or up-rate test for an HCA. However, during the course of assessing data for ECDA or ILI, it may become apparent that pressure testing is the only feasible option. If so, the Company will perform a pressure test." *Id.* at p. 40.

44. In its 2004 Baseline Assessment Plan, PG&E identified 456.6 miles of pipeline that had manufacturing threats, and 88.75 miles with construction threats. Ex Joint 46 (Coversheet and summary page of PG&E's 2004 Baseline Assessment Plan)

45. According to PG&E's 2004 Baseline Assessment Plan, PG&E believed that 100% of its pipelines were subject to the external corrosion threat. Ex Joint 46 (Coversheet and summary page of PG&E's 2004 Baseline Assessment Plan)

46. PG&E used External Corrosion Direct Assessment (ECDA) to assess the external corrosion threat on its pipelines. ECDA, however, does not detect missing or cracked seams and the "code doesn't allow for the use of ECDA in the evaluation of manufacturing threats." Joint RT 960:3-961:7 (Keas/CPSD)

47. According to PG&E's 2009 Baseline Assessment Plan, of the 1021 miles to be assessed by December 17, 2012 "zero miles will be assessed using pressure testing. Ex CCSF-8 (8/12/11 NTSB Factual Addendum Report) at p. 28

48. As of September 9, 2010, PG&E's TIMP "had identified 11.15 miles of piping to be assessed for manufacturing seam threats." Ex CCSF-1 (Exhibit 3 to Testimony of John Gawronski: PG&E Response to Data Request CCSF_004-Q08 in R.11-02-016).

49. Of these approximately 11 miles, PG&E had assessed 4.9 miles of piping using an in-line inspection tool called Transverse Field Inspection. *Id.*

50. PG&E intended to inspect the remaining 6.2 miles using a similar tool. *Id.*

51. In March 2012, PG&E identified 523 pipeline segments (247,206 feet or over 46 miles of pipeline) that it admits have unstable seam-related manufacturing defects Ex CCSF-1 at p. 9.

52. As of March 2012, PG&E had not yet assessed those defects. *Id.*

53. In San Francisco alone there are 6 segments on Line 101, totaling approximately one mile (5,333 feet) in length, that have unstable manufacturing defects. *Id.*

54. These segments were all installed in 1953. *Id.*

55. These segments with oxy-acetylene welds in San Francisco, which have been identified as being susceptible to brittle like cracking, 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. *Id.*

56. There are also 22 segments on Line 109, amounting to nearly 2 miles (9,781 feet) of pipeline, that have unstable seam-related manufacturing defects. *Id.*

57. Most of these segments were installed in 1932, and many also have oxy-acetylene girth welds. *Id.*

58. In October 2009, PG&E hired an outside consultant to perform a high-level audit of its integrity management program and identify strengths and weaknesses. Ex Joint 48 (October 20, 2009 WKMC Review of Pipeline IMP Documents).

59. The consultants identified PG&E's risk assessment methodology as a "weakness." *Id.* at p. 1.

60. RMP-06 was one of the documents considered in this audit. *Id.*

61. Based on this review, the consultant found that PG&E's risk assessment methodology suffered from "significant weaknesses." *Id.* at p. 3.

62. The two of the significant weaknesses in PG&E's risk assessment methodology were weighting and awarding of points or scores. *Id.*

63. Weightings "carry inherent risks of bias and masking" and some "reasons why weightings are currently out of favor and not used in robust risk assessment include the following: force pre-conceived results, difficult to support technically, potential for masking risk issues." *Id.*

64. Using points or scores "often has inadequate defensible linkage to real world phenomena." *Id.*

65. An April 12, 2010 PG&E internal memorandum shows that PG&E purposefully under-calculated potentially unstable manufacturing threats for assessment. Ex Joint 9 (PG&E Response to CPSD Data Request 015-Q01, Attachment 692 in I.11-02-016).

66. The April 12, 2010 memorandum "documents that the operating pressure in a pipeline with a manufacturing seam threat, that has previously not been pressure tested, will not activate unless the historical operating pressure (MOP) plus 10 percent is exceeded." *Id.*

67. As PG&E uses MOP in this context, it is the MAOP for the pipeline system, i.e. the entire line as opposed to one segment. *Id.*

68. In the memorandum, PG&E acknowledges that section 192.917(e)(3), and ASME B31.8S do not specify any allowance past the MOP (as it is used in that memorandum). *Id.*

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

70. Older DSAW pipe is more susceptible to rupture. Ex Joint 49 9(Integrity Characteristics of Vintage Pipelines (INGAA report)) at p. E-6.

71. Based on this report over 44% of the incidents are attributed to pipe produced in 1950, and another 17% in 1949, 1951, or 1952. *Id.*

72. PG&E admitted that the INGAA report is one of the sources of information that PG&E uses to determine whether there are any defects in its older pipelines as part of its Integrity Management Program. Joint RT 970:21-26 (Keas/CPSD).

73. PG&E provided a Moody's report that shows that some of the steel used by Consolidated Western for PG&E's pipelines came from the Kaiser Company. Ex PG&E -7 (Tab 4-20: July 19, 1949 Moody's Report) at p. 2 ("the balance of the steel plates were supplied by Kaiser Company, Inc., and rolled at their plant in Fontana California.").

74. The INGAA report specifically identifies the Kaiser Company as being the predominant supplier of SSAW and DSAW pipelines that resulted in reported incidents. Ex Joint 49 at p. E-6 .

75. During the years 2002-2009, 6 out of the 17 reportable incidents involving longitudinal seam welds occurred on DSAW pipelines. Pinhole leaks accounted for all six reportable incidents. Ex PG&E-1 at p. 5-10.

76. PG&E has stated that it believes that segment 180 was constructed with DSAW pipe from Consolidated Western. Ex PG&E-1 at p. 2-1.

77. During the hearings, PG&E admitted that if segment 181 was identified as having a manufacturing threat in 2004 BAP because segment 181 was identified as being over 50 years old, segment 180 should also have been identified as having a manufacturing threat because it was also over 50 years old in 2004. Joint RT 966:20-26 (Keas/CPSD).

78. When questioned why PG&E's TIMP did not identify segment 180 as having a manufacturing defect, PG&E's witness asserted that she believed it was because "we thought we knew what the installation was, which was in, I believe 1956." Joint RT 967:5-7 (Keas/CPSD).

79. PG&E asserted that it over-pressurized its pipelines "to avoid [pressure testing] and any potential customer curtailments that may result." CCSF-1 (Exhibit 11 to Testimony of John Gawronski: PG&E's Amended Data Response NTSB Exhibit 2-AI of the San Bruno Investigation (Docket No. SA-534)).

80. PG&E "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." *Id.*

81. Increasing the pressures in this way can affect the stability of manufacturing and construction (especially weld) defects in pipeline segments. Ex CCSF-1 at p. 16.

82. PHMSA believes that "if you're adjusting the pressure periodically, you need to … make that part of your overall assessment of the risk on that pipeline.'" Ex CPSD-9 at p. 37.

83. In addition, it appears that PG&E is the only operator who followed this practice. *Id.* ("PHMSA officials were unaware of any other operators following such a practice.")

84. PG&E over-pressurized segments of Line 101 and Line 109 within the City and County of San Francisco on December 11, 2003. Ex CCSF-1 (Exhibit 11 to Testimony of John Gawronski: NTSB Exhibit 2-AI of the San Bruno Investigation (Docket No. SA-534)), p. 4 of spreadsheet titled "NTSB_036-005 Amended.")

85. Prior to December 11, 2003, the five-year MOP for the Line 101 segments in San Francisco (segment numbers 181 to 201) was 223.5 psi. Ex CCSF-1 (Exhibit 12 to Testimony of John Gawronski: PG&E Response to Data Request OII_DR_CCSF_003-Q05 in I.11-02-016).

86. The five-year MOP for Line 109 segments in San Francisco (segment numbers 195.2 to 248) was 149.8 psi. *Id*

87. On December 3, 2011, PG&E raised the pressure on these segments of Line 101 to 249.42. Ex CCSF-1 (Exhibit 11 to Testimony of John Gawronski: NTSB Exhibit 2-AI of the San Bruno Investigation (Docket No. SA-534), p. 4 of spreadsheet titled "NTSB_036-005 Amended.")

88. Similarly, PG&E raised the pressures on these segments of Line 109 to 150.01 psi. *Id.*

89. PG&E's witness admitted that it is very possible that PG&E exceeds its MAOP everyday on every pipeline. Joint RT 750:2-20 (Zurcher/CCSF).

90. PG&E's witness admitted that "I don't believe a prudent operator would exceed MAOP on purpose." Joint RT 788:7-8 (Zurcher/CCSF).

91. It is Mr. Zurcher's opinion that "prudent pipeline operators manage system pressures to never exceed MAOP, which often means that a safety margin below MAOP is necessary." Ex Joint 35 (Determination of Available Capacity and A Review of Maintenance on the El Paso Natural Gas Co. System for the Period November 1, 2000 through March 31, 2001) at p. 12.

92. Even after the San Bruno explosion, PG&E still asserts that "even a 20-pound excursion (equivalent to 5% over the 400 psig MAOP) would not be enough to render a manufacturing threat unstable." Ex PG&E-1c at p. 4-26.

C. Cyclic Fatigue

93. The NTSB found that fatigue cracking weakened the pipe segment that ruptured. Ex CPSD-9 at p. 124 (Finding 5)

94. PG&E admits the rupture of segment 180 was caused by a ductile tear that grew from "fatigue cracking [...] to a point that the relatively small increase in pressure on September 9, 2010 caused the Pup 1 longitudinal seam to rupture." Ex PG&E-1 at p. 3-7.

95. PG&E did not incorporate cyclic fatigue or other loading conditions into their segment specific threat assessments and risk ranking algorithm in either its 2005 or 2010 Integrity Management Protocol Matrices. Ex CPSD-1 at p. 51.

96. PG&E lacks a documented record that it evaluated the pressure cycles on its pipelines. CCSF-1 at p. 18.

97. PG&E's RMP-06 does not even list cyclic fatigue as one of the threats to be considered. Joint RT 110:5-17 (Keas/CCSF).

98. To perform the cyclic fatigue analysis, an operator must track its pressure histories. CCSF-1 at p. 17.

99. 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. *Id.*

100. Next, the operators must identify what constitutes a significant threat due to severe or moderate pressure/stress cycles. Id.

101. Operators must count the number of severe cycles experienced by the pipeline. *Id.*

102. 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. *Id.*

103. Based on this analysis, operators calculate an expected time to failure and time for reassessment. The expected time to failure is the "minimum amount of time that we would expect to see a failure." 704:13-14 (Kiefner/CPSD).

104. This calculation is not 100% predictive, i.e. the pipeline could fail before or after that time. 706:21-28. (Kiefner/CPSD).

105. The time for re-assessment is half the expected time to failure. In other words, operators apply a safety factor of two by taking the calculated time to failure and dividing that number by two. 707:3-22 (Kiefner/CPSD).

106. Upon reaching time for assessment, operators have two options: "one is to hydrostatically test the pipeline again to reset the clock. The other is to run in-line

inspection with a crack detection tool that's capable of finding the defects." 708:7-12." (Kiefner/CPSD).

107. The results of the cyclic fatigue analysis will vary depending on the specific characteristics of the pipelines subject to cyclic fatigue. 780:7-10 (Kiefner/CCSF).

108. In March 2012, Kiefner and Associates wrote a report addressing the threat of cyclic fatigue on PG&E's peninsula pipelines based on the pressure histories for 10 years prior to September 9, 2010 (KAI report). 801:16-21 (Kiefner/CCSF).

109. The report finds that some segments in PG&E's gas transmission system have passed the time for reassessment and some have even passed their expected time to failure based on seam weld fatigue. Ex. CCSF-5.

110. Failure due to seam-weld fatigue on high pressure transmission lines tends to lead to rupture. 797:16-18 (Kiefner/CCSF)

111. The report makes clear that several of the key assumptions contained in PG&E's testimony are inapplicable to the older vintages of PG&E's gas transmission system. 780:22-25 (Kiefner/CCSF).

112. One key assumption is based on the vintage of the pipe. Pipelines of older vintage were not tested to as high a level, or possibly not even at all. CCSF-05 (March 2012 Kiefner and Associates Inc. Final Report: Analysis of the Effects of Pressure-Cycle-Induced Fatigue-Crack Growth on the Peninsula Pipeline) at p. 1.

113. Not all of PG&E's pipelines were tested to the highest levels. Several types lower grade pipe that are present in PG&E's system and are more susceptible to seam failure are PG&E specified grade, API 5L Grade A and Grade B pipe. Ex CCSF-05 at p. 1.

114. API 5L Grade A and Grade B pipe were subject to minimum test pressure of only 60 percent SMYS. Ex CCSF-05 at p. 2.

115. In some cases, the calculated fatigue life for these types of pipe is on the order of 50 years. *Id.*

116. Not all of PG&E's pipelines may been pressure tested. Based on the NTSB's interview of a former Consolidated Western employee it appears that not every piece of pipe made at Consolidated Western was subjected to a mill test. Ex CCSF-08 (NTSB Operations Chairman Factual Report Addendum, Dated 8/12/11).

117. In the NTSB's deposition of a former Consolidated Western employee, the employee stated that he believed only 1 in 50 pipes manufactured were subject to a mill test. Ex CPSD-305 (Deposition of Arthur "Mike" Massaglia) at p. 11:4-5.

118. PG&E admits that cyclic fatigue was a threat to its pipelines even before the explosion on September 9, 2010.

> "Q: So even before the San Bruno explosion happened, based on the operating pressures, the threat of cyclic fatigue was present on PG&E's pipelines?
>
> A: Well, on the basis of these calculations, you could infer that."

801:16-21 (Kiefner/CCSF).

119. Based on these considerations, the manufacturing techniques and the lack of documented pressure tests, PG&E should have considered cyclic fatigue a threat to its pipelines before the September 9, 2010 rupture occurred. Ex CCSF-05 at p. 2.

120. Based on the report's analysis, one segment of Line 109 made with PG&E Spec pipe, which was installed in 1936 had an expected time to failure of 139 years, and a time for reassessment of 70 years. Ex CCSF-05 at p. 2

121. Based on the ten year pressure history prior to September 9, 2010, the cyclic fatigue analysis shows that this segment should have been hydrotested or in-line inspected for crack growth in 2006. 793:25-794:28 (Kiefner/CCSF)

122. It also appears that this segment has not been pressure tested as of March 2012. 796:1-22 (Kiefner/CCSF).

123. In addition, the KAI report finds that a segment of Line 132 installed in 1948 with a SMYS of 33,000 psi that has not been pressure tested passed time to failure in 2008. 797:19-798:19 (Kiefner/CCSF).

124. Yet another segment of Line 132 passed its time to failure in 1997. 798:20-799:1 (Kiefner/CCSF).

125. The KAI report also makes clear that the threat of cyclic fatigue exists on DSAW pipelines too. 800:19-801:7 (Kiefner/CCSF).

126. There may have been additional over-pressurizations of PG&E's pipelines that could further shorten the expected times to failure. 804:26-805:3 (Kiefner/CCSF).

127. PG&E has admitted that it lost records relating to over-pressurizations from 2005 and 2007, and although it was able to provide a partial list of lines that it over-pressurized, it "cannot confirm that this represents all such events." Ex CCSF-7 (PG&E Response to CCSF Data Request 004-Q01 and Q05 in I.11-02-016) See response to Q-01.

128. PG&E only "began tracking over-pressurization events in the Gas Events database in September 2008." Ex CCSF-1 (Exhibit 13 to Testimony of John Gawronski: PG&E Response to Data Request TURN_040-27 (A.09-12-020)).

129. PG&E states that prior to 2008 it experienced approximately 10 to 20 untracked over-pressurization events each year. *Id.*

130. PG&E also admitted that it does not have pressure histories for the entire year of 1999. Ex CCSF-1 (Exhibit 14 to Testimony of John Gawronski: PG&E Response to Data Request CPUC_015-10 (I.11-02-016)).

131. PG&E did not incorporate the loss of the 1999 SCADA pressure records into its integrity management model because it believes that "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." *Id.*

132. The fact that PG&E did not track over-pressurization events prior to 2008 means that it cannot know the full extent to which cycling has affected the integrity of its pipelines and the stability of the manufacturing defects. CCSF-1 at p. 18.

133. PG&E's witness stated that he had no reason to believe that PG&E lacked the resources and ability to perform this analysis. 741:6-10(Kiefner/CPSD).

134. PG&E has still has not asked Kiefner and Associates to perform a cyclic fatigue analysis for other lines that it over-pressurized. 809:8-18 (Kiefner/CCSF).

D. Interactive Threats

135. 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). Ex CCSF-1 at p. 19.

136. RMP-06 does not include interactive threats. Ex PG&E 6 (Tab 4-6 (RMP-06), Joint RT 1110:14-20 (Keas/CCSF).

137. ASME B31.8S-2004 requires operators to consider interactive threats. Ex CCSF-1 at p. 19; Ex Joint-28 (ASME B.31.8S) section 2.2.

138. This is particularly important when considering manufacturing and construction threats as well as pipe seam threats. Ex CCSF-1 at p. 19.

139. Interacting threats can result in otherwise stable defects becoming unstable, and necessitate assessment. *Id*

140. It is clear that PG&E relied on the manufacturing and construction defects in its system being stable, and failed to consider the interactive nature of the threats on its lines, or that changing pressures could affect the stability of the manufacturing and construction defects. *Id*

E. Emergency Response

141. On the evening of the rupture, PG&E "did not notify emergency responders that the fire was being fed from a rupture in PG&E's natural gas transmission line." CPSD-9 at p. 100; RT 284:22-23 (Almario/CPSD).

142. In general, PG&E's first responders to a gas incident are general its Gas Service Representatives (GSRs). RT 297:23-298:2 (Almario/CPSD).

143. The NTSB found although GSRs are directed to evaluate the danger to life and property, assess damage, and make or ensure that conditions are safe, PG&E's emergency response procedures for Gas Service Representatives does not direct them to call 911. CPSD-9 at p, 14, fn 25.

144. PG&E's Company Gas Emergency Plan "defines the required procedures that all local gas operating departments must have in place to respond to gas emergencies." Ex PG&E-39 at p. Part I-1

145. The plan states that the first step in "GAS EMERGENCY RESPONSE POLICIES" is to "shut off gas if possible." *Id.* at p. Part 1-37.

146. PG&E did not turn of the gas for 95 minutes. CPSD-9 (NTSB Report Executiuve Summary at p. x)

147. Further under External Notification Requirements, the Gas Emergency Plan states "local fire departments must be contacted whenever a gas emergency poses a threat of fire or explosion. Fire department can assist in fire suppression, evacuations, and traffic control." Ex PG&E-39 at p. Part 1-40.

148. Depending on circumstances at the scene, initiate a previously developed joint action to control the gas emergency." *Id.* at p. Part 1-47.

149. Despite this direction, and even though it had knowledge that the fire was near a gas transmission line, PG&E did not call the fire department when it dispatched its GSR at 6:23 pm. RT 360:24-361:12 (Almario/CCSF).

150. As of 6:31 pm (20 minutes after Line 132 ruptured), PG&E's Concord Dispatch knew that the explosion may have involved a PG&E's gas transmission line in the area. Ex PG&E 40 (NTSB San Bruno Event Timeline, Exhibit 2-DX) at p. 8.

151. Although PG&E did not call 911 at that time, PG&E admits that first responders would have been aided by the knowledge that the possibility that the fire was being fed by a high pressure transmission line. RT 355:12-16 (Almario/CCSF).

F. Credibility of PG&E Witnesses

152. Prior to submitting his testimony in this case, Mr. Zurcher and his associates at P-PIC were retained by PG&E's Board of Directors to perform an independent review of PG&E's natural gas transmission and distribution practices (Blacksmith Audit). Ex Joint 31 (PG&E Response Data Request CCSF_002-Q02, Attachment 1)

153. This "review was intended to identify industry practices that PG&E could adopt to improve the operations and maintenance of its natural gas system." *Id.*

154. Mr. Zurcher considered this to be a top to bottom examination of PG&E's Customer Care, Field Operations, Prevention and Maintenance, Damage Prevention, Information and Support, Capital and Expense Budgeting, Safety Culture, Public Awareness, and Emergency Response and Preparedness. Joint RT 696:13-697:24 (Zurcher/CCSF).

155. Mr. Zurcher was the lead for the Blacksmith Audit's review of PG&E's prevention and maintenance practices. Joint RT 703:3-22 (Zurcher/CCSF).

156. Included in this part of the audit were assessing PG&E's pressurization practices, and PG&E's integrity management. Joint RT 703:23-704:8 (Zurcher/CCSF).

157. Despite the very clear relationship between this aspect of the Blacksmith Audit and the scope of this investigation, Mr. Zurcher stated that he did not believe that any of the facts from the Blacksmith Audit were relevant to the San Bruno testimony. Joint RT 699:8-17 (Zurcher/CCSF).

158. When asked specifically if was directed to not consider the Blacksmith Audit when preparing testimony for this investigation, Mr. Zurcher was unable to answer no ("Q: Were you directed to not consider this audit in your testimony for either case? A:

Not that I recall. I am just not sure. I should say that. I'm not sure.") . Joint RT 698:1-5 (Zurcher/CCSF)

159. PG&E very carefully manipulated the scope of Mr. Zurcher's testimony by providing him with only a limited set of materials upon which he was asked to prepare testimony for this case. Joint RT 705:19-27 (Zurcher/CCSF).

160. When discussing his 2007 study on the stability of manufacturing and construction defects, Mr. Kiefer stated that he believed the purpose of the study was " to prove the point that in a natural gas pipeline, this cyclic fatigue is simply not a threat." RT 716:26-717:2 (Kiefner/CPSD).

161. As Mr. Kiefner noted, this 2007 report is premised upon several key assumptions, and that not all of the assumptions are applicable to PG&E's pipelines. RT 780:22-782:1 (Kiefner/CCSF).

162. In Mr. Kiefner's view, in absence of specificity, the cyclic fatigue analysis is "somewhat arbitrary unless you actually do a study of a particular material in a particular environment…" RT 687:6-9 (Kiefner/CPSD).

163. Mr. Kiefner's firm (Kiefner and Associates Inc.) prepared a report (KAI Report) applying the analysis from the 2007 study to the specific characteristics of PG&E's peninsula pipelines. Ex CCSF-5

164. Mr. Kiefner asserted that his testimony was based upon a review and analysis of PG&E's gas transmission pipeline system, with specific focus on data and records relating to the physical assets and operations of gas transmission Line 132; records related to PG&E's TIMP; and the testimony provided by other parties in this proceeding. Ex PG&E-1 at p. 6-2.

165. The KAI report was prepared in March 2012. Ex CCSF-5.

166. Even though the KAI report was available to Mr. Kiefner prior to submitting his testimony in this case, he did not consider the report prior to preparing testimony. RT 783:26-28 (Kiefner/CCSF).

167. While Mr. Kiefner was familiar with the KAI report's analysis, he "didn't see anything that I needed to quote from this report." RT 784:6-19 (Kiefner/CCSF).

168. In other words, even though Kiefner's firm had conducted a detailed assessment of the threat of cyclic fatigue for Line 132 for PG&E prior to the time he submitted his testimony, he did not believe the KAI report was relevant to the Commission's examination of PG&E's "past operations, practices and other events or courses of conduct that could have led to or contributed to the San Bruno explosion and fire." RT 784:6-19 (Kiefner/CCSF).

169. In a data response Mr. Kiefner stated that "Mr. Kiefner has no personal basis for a conclusion that the pipe used in Segment 180 was subject to a mill test." Ex CCSF-6 (PG&E Response to Data Request CCSF_001-Q02).

170. On cross-examination, when Mr. Kiefner was asked about whether or not segment 180 was subject to a mill test, he asserted that he believed that it was. RT 780:9-25 (Kiefner/CCSF).

171. When further questioned about this inconsistency, Mr Kiefner stated that he was unfamiliar with the data response, had not prepared the data response, that he had never been asked about his personal knowledge related to the question in the response, and that he did not agree with the response. RT 789:3-14.