BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company to Determine Violations of Public Utilities Code Section 451, General Order 112, and Other Applicable Standards, Laws, Rules and Regulations in Connection with the San Bruno Explosion and Fire on September 9, 2010.	I.12-01-007 (Filed January 12, 2012)

OPENING BRIEF
OF PACIFIC GAS AND ELECTRIC COMPANY
REVISED PER ALJ'S RULING

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I. INTRODUCTION AND SUMMARY[1]

In 1956, PG&E unknowingly installed six 4-foot pieces of pipe (so-called "pups") in Line 132 that never should have been put into service. On September 9, 2010, one of those pups ruptured as a result of the combination of an initial defect (a missing interior weld), a ductile tear likely caused by a post-installation hydro test, and 50 years of fatigue crack growth. The rupture caused an explosion and fire that killed eight people, injured dozens of others and damaged a large part of the Crestmoor neighborhood in San Bruno. PG&E deeply regrets the loss of life and injuries and the effect on the San Bruno community. PG&E is morally and legally responsible for this tragic accident and has acknowledged liability to those injured. [2] As a result of the accident, PG&E – along with the industry as a whole – has learned many lessons, and the company has committed to making real and lasting changes to enhance the safety of its gas system. PG&E knows that its gas system operations were not what the company, the Commission or PG&E's customers expect, and has acknowledged this shortcoming and embarked on major improvement efforts. [3] PG&E has taken and continues to take significant steps at shareholder expense to bring its gas operations up to the highest quality.[4]

This proceeding is thus not about proving PG&E responsible for the accident. Rather, as the Commission declared, it "focus[es] on PG&E's past actions and omissions, to determine whether PG&E has violated laws requiring safe utility gas system practices," thereby causing the September 9, 2010 accident. [5] It is not a prudence review; its purpose is not to judge whether PG&E's past practices were "deficient" in some way or could have been better. The purpose of this proceeding is narrower; it is to determine whether PG&E violated laws.

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[1] Pursuant to *England v. La. State Bd. of Med. Exam'rs*, 375 U.S. 411 (1964), PG&E expressly reserves its federal constitutional and any other federal claims and reserves its right to litigate such claims in federal court following any decision by the Commission, if necessary. While PG&E cites federal cases, including Supreme Court decisions, in this brief, they are cited only to the extent that they provide analogous authority for construing the California Constitution and/or California law.

[2] *See* Ex. PG&E-1a at 1-1 (PG&E/Yura).

[3] Ex. PG&E-1a at 1-2 (PG&E/Yura).

[4] Ex. PG&E-1a at 1-1 to 1-2, 13-1 to 13-16 (PG&E/Yura).

[5] *Order Instituting Investigation on the Commission's own Motion into the Operations and Practices of Pacific Gas and Electric Company to Determine Violations of Public Utilities Code Section 451, General Order 112, and Other Applicable Standards, Laws, Rules and Regulations in Connection with the San Bruno Explosion and Fire on September 9, 2010,* I.12-01-007, 2012 Cal. PUC LEXIS 39, at 10.

In keeping with the focus of the proceeding, the Consumer Protection and Safety Division (CPSD)[6] alleges numerous violations of law against PG&E. The alleged violations fall into three categories. First, CPSD alleges the following violations based on the pipeline safety regulations:[7]

- "By failing to follow its internal Work Procedures for the Milpitas Terminal work, PG&E violated Part 192.13(c), which creates a mandatory obligation for utilities to follow the procedures required to be adopted as part of the Integrity Management rules (Part 192, Subpart O)."[8]
- "By failing to adequately maintain written procedures for conducting operations and maintenance activities and for emergency response, PG&E violated Parts 192.605(c) and 192.615."
- "By faili ng to conduct adequate data gathering and integration to evaluate potential threats to pipeline safety, PG&E violated Part 192.917(b)."
- "By failing to adequately consider cyclic fatigue in its threat analysis, PG&E violated Part 192.917(e)(2)."
- "By failing to identify Segment 181 and other similar segments as having a potentially unstable manufacturing threat, PG&E violated Part 192.917(e)(3)."
- "By failing to assess the integrity of Segments 180 and 181 (and other similar segments) using an appropriate assessment technology, PG&E violated Part 192.921(a)."
- "PG&E failed to conduct prompt alcohol testing of the operators doing the Milpitas work in violation of Part 199.225."

Second, CPSD alleges the following violations, some purportedly continuing for decades, based on Public Utilities Code Section 451:[9]

- "PG&E did not maintain a safe condition on Segment 180 of Line 132 in San Bruno, California. Many factors contributed to the unsafe condition, including the installation of substandard pipe, failing to follow accepted industry standards during construction, failing to perform adequate inspections, failing to keep adequate safety records, failing to comply with the integrity management rules, failing to operate safely at the Milpitas Terminal, failing to promptly and safely respond to the incident, and management failing to foster a culture that valued

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[6] CPSD recently changed its name to the Safety and Enforcement Division. To be consistent with the evidence and pleadings already submitted in this proceeding, PG&E uses CPSD in this brief.

[7] Ex. CPSD-1 at 163 (CPSD/Stepanian). Each of the following bullets is CPSD's words.

[8] Although this is what CPSD alleges, the work at Milpitas Terminal on September 9, 2010 had nothing to do with integrity management. Nor is 49 C.F.R. § 192.13(c) limited to integrity management. It provides as follows: "Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part [Part 192]."

[9] Ex. CPSD-1 at 162 (CPSD/Stepanian). Each of the following bullets is CPSD's words.

safety over profits at PG&E. These factors all contributed to the explosion and fire at San Bruno on September 9, 2010, and together constitute an unreasonably unsafe condition on Segment 180 that lasted from 1956 to 2010, in violation of Public Utilities Code Section 451."

- "During construction of Segment 180 PG&E did not comply with the then-current industry standards for construction of its pipelines in violation of ASA B31.1.8 standards, creating an unsafe condition in violation of Section 451. Specifically, PG&E did not follow the established detailed requirements in ASA B31.1.8-1955 on yield strengths in pipe materials (Section 805.54 of B31.1.8), welding (Section 811.27), fabrication (API 5LX), testing (Section 841.411), records of testing (Section 841.417), and establishing MAOP (Section 845.22)."
- "PG&E violated various requirements of 49 CFR Part 192, Subpart O, in its implementation of the Integrity Management process, including incomplete data gathering and integration, flawed threat identification, flawed risk assessment and using an incorrect assessment methodology. This allowed an unsafe condition to persist in violation of Section 451."

Lastly, CPSD alleges the following violation based on Commission Resolution L-403:

- "By erasing a digital video recording made during the incident at its Brentwood control room, PG&E destroyed potentially relevant information in violation of Commission Resolution L-403 which specifically ordered PG&E to preserve any potential evidence."[10]

As the "prosecutor" in this enforcement proceeding, CPSD bears the burden of proof on every violation it asserts. Given the unprecedented fines, penalties and remedial relief the Commission has indicated it may impose should violations be proven, CPSD should be held to prove each alleged violation by clear and convincing evidence (*see* Section III.A below). But even if the Commission applies the lesser preponderance of the evidence standard, the evidence demonstrates that – with two exceptions noted below – CPSD has not met its burden.

To respond to CPSD's allegations, PG&E turned to the leading experts in the pipeline industry:

- John Zurcher, a long-time industry participant and co-drafter of the federal integrity management regulations, testified regarding the relevance of historic records to gas engineering and integrity management decisions, and integrity management practices and regulation generally.[11]

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[10] Ex. CPSD-1 at 162 (CPSD/Stepanian). After release of CPSD's report, PG&E determined and informed CPSD that the video never was recorded, thus there was nothing that could have been preserved. CPSD did not address this alleged violation in its rebuttal testimony (Ex. CPSD-5), but has not formally withdrawn it.

[11] Ex. PG&E-1 at 5-1 to 5-17 (PG&E/Zurcher); Joint R.T. 2-81, 642-889 (PG&E/Zurcher).

- John Kiefner, widely considered the preeminent expert on manufacturing and construction defects in pipelines, testified about cyclic fatigue on natural gas pipelines.[12]
- Thomas Miesner, a long-time pipeline operator and former director at several pipeline companies who now teaches operational subjects to the pipeline industry, testified regarding PG&E's SCADA system and the local pressure control system at the Milpitas Terminal.[13]
- David Bull, a former associate staff member of the Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Training and Qualifications with years of experience instructing gas operators on emergency response regulations, testified regarding PG&E's emergency plan's compliance with gas safety regulations.[14]
- Robert Caligiuri, Ph.D., a professional metallurgical engineer who has investigated over 25 failures involving pipelines, testified regarding the root cause of the Line 132 rupture, including the potential that a post-installation hydro test on Segment 180 initiated the ductile tear that ultimately grew to rupture.[15]

These experts concluded that PG&E's practices were consistent with industry standards and pipeline safety regulations. PG&E deeply regrets the accident of September 9, 2010, and acknowledges its practices could have been better but, at the time, its gas operations were in line with common practice and regulatory requirements.

CPSD's attempt to use Public Utilities Code Section 451 as a free -floating safety law runs afoul of the due process clause of the California Constitution.[16] As discussed in Section III.B below, Section 451 is a rate – not a safety – provision. Even if it were a safety provision, it would be too vague to provide a lawful foundation for civil penalties. Unlike the specific regulations on which CPSD relies, Section 451 does not provide the utility fair notice of the conduct that CPSD now claims violates the law. Rather, CPSD's Section 451 allegations are the product of hindsight, changed expectations following the accident, and two-plus years of unsurpassed scru tiny into PG&E's operations over the past six decades. Where a specific

[12] Ex. PG&E-1 at 6-1 to 6-8 (PG&E/Kiefner); R.T. 684-725, 730-839 (PG&E/Kiefner).
[13] Ex. PG&E-1 at 9-1 to 9-14 (PG&E/Miesner); R.T. 843-65 (PG&E/Miesner).
[14] Ex. PG&E-1 at 11-1 to 11-29 (PG&E/Bull); R.T. 411-31 (PG&E/Bull).
[15] Ex. PG&E-1 at 3-1 to 3-17 (PG&E/Caligiuri); R.T. 1051-1205 (PG&E/Caligiuri).
[16] Cal. Const., art. I, § 7.

regulation does not address particular conduct, CPSD uses Section 451 to claim that the conduct constitutes a safety violation punishable with fines, penalties and prescriptive remedial action. The Constitution does not allow such a results-oriented prosecution.

Of the specific regulatory violations CPSD has alleged, two have merit:

- PG&E's Work Procedure for preparing the clearance form for the Milpitas Terminal electrical work is part of the operations and maintenance procedural manual required by 49 C.F.R. § 192.605. Although oral communications between Gas Control and the individuals doing the work at Milpitas Terminal supplied all the necessary information, the clearance form prepared for the work did not meet the requirements of PG&E's Work Procedure. That amounts to a violation of 49 C.F.R. § 192.13(c), which requires following those procedures.
- PG&E did not test personnel at Milpitas for alcohol within the time required by 49 C.F.R. § 199.225.

CPSD failed to prove each of the remaining violations of the pipeline safety regulations and Section 451:

A. Construction of Segment 180: CPSD's contentions that PG&E violated the law because the 1956 construction of Segment 180 did not comply with standards set forth in ASA B31.1.8-1955 and API 5L (1954) fail because (1) the alleged violations are based on voluntary industry guidelines, not legal requirements, and (2) none of the cited standards applied to the Segment 180 construction.

B. PG&E's Integrity Management Program: CPSD failed to prove that PG&E's integrity management program violated any regulation or law:

- CPSD did not prove that PG&E failed to gather any particular data element required by the ASME B31.8S minimum requirements. CPSD's approach did not take account of the fact that the regulations expressly recognize that historic pipeline records were not complete, as Mr. Zurcher's testimony showed.
- CPSD failed to establish that the data in PG&E's GIS system or PG&E's use of conservative assumed values violated any regulation or statute. As Mr. Zurcher's testimony showed, the data in PG&E's GIS system is consistent with industry norms and regulatory requirements.

- CPSD did not prove that PG&E's evaluation of cyclic fatigue violated any regulatory requirement. Before the San Bruno accident, neither the industry nor the regulators considered cyclic fatigue to be a significant threat to natural gas pipelines, as Mr. Kiefner testified. PG&E appropriately evaluated cyclic fatigue consistent with the regulations and industry understanding. None of CPSD's prior audits of PG&E's integrity management program found otherwise.

- CPSD's allegation relating to PG&E's threat identification on Line 132 depends on the hindsight knowledge of the accident to suggest that PG&E should have regarded DSAW pipe, considered by the federal integrity management regulations, ASME standards, and industry experts to be of the highest safety, to have a longitudinal seam threat.[17]

- CPSD failed to prove that PG&E's use of External Corrosion Direct Assessment (ECDA) to assess the integrity of Line 132, Segment 180 violated any statute, code or regulatory guidance. CPSD faulted PG&E for not conducting an integrity management assessment on Segment 180 designed to detect long seam defects, such as an in-line inspection or hydro test.[18] The evidence demonstrated, however, that based on the information it had, PG&E had no reason under the integrity management rules to identify Segment 180 as potentially possessing a long seam manufacturing threat that could warrant such an assessment. Even the most comprehensive and thorough integrity management data gathering process would not have turned up a record describing a defective pup – no such record would have been created because, had the defect been known, PG&E would not have installed the pipe. And if the presence of the pups had been identified, the evidence was undisputed that PG&E would have immediately removed the pups, not perform a different type of integrity management assessment.[19]

C. Recordkeeping Violations: CPSD's allegation that the state of PG&E's Segment 180 records constituted a legal violation was not supported by the evidence and was based on

[17] Ex. PG&E-1 at 3-5 (PG&E/Caligiuri); Ex. PG&E-1 at 5-9 to 5-12 (PG&E/Zurcher); Joint R.T. 967 (PG&E/Keas); 49 C.F.R. §§ 192.113, 192.917(e); Ex. Joint-28 (ASME B31.8 (2004)).

[18] *See, e.g.,* Ex. CPSD-1 at 26 (CPSD/Stepanian).

[19] Joint R.T. 337-38 (PG&E/Harrison); Joint R.T. 1019, 1066 (PG&E/Keas); Joint R.T. 692 (PG&E/Kiefner).

non-mandatory and/or non-existent recordkeeping standards. To the extent voluntary guidelines addressed construction recordkeeping in 1956, the evidence established that PG&E possessed the appropriate records.

D. PG&E's SCADA System and the Milpitas Terminal: CPSD asserted that various conditions related to PG&E's Supervisory Control and Data Acquisition (SCADA) system and the local control system at Milpitas Terminal constituted a safety violation under Section 451.[20] But the undisputed evidence is that the pressure control system at Milpitas Terminal functioned as designed and kept the pressure on Line 132 and at the rupture site below the maximum allowable operating pressure (MAOP). CPSD itself acknowledged that, on September 9, 2010, the pressure on Line 132 never exceeded what is permitted under the law.[21] CPSD also conceded that there "are no specific requirements in the federal or state codes which address" the conditions CPSD claims created a safety issue in violation of Section 451.[22] PG&E cannot have violated the law when the SCADA and pressure limiting systems designed to catch and cap rising gas pressure so that regulatory maximums are not exceeded did exactly that.[23]

E. PG&E's Emergency Response: PG&E's emergency plans complied with the applicable regulations, as CPSD's own pre-San Bruno audits concluded. While CPSD complains about the alleged slowness of PG&E's emergency response on September 9, 2010, there are no accepted standards for the time to respond to an emergency, and PG&E's testimony showed that its response was reasonable under the circumstances at the time.

F. PG&E's Safety Culture and Financial Priorities: Though CPSD alleged no violations on the subject, the evidence showed that CPSD's assertions[24] regarding PG&E's spending on the gas transmission business and its overall safety culture were mistaken and did not withstand scrutiny by PG&E's expert, Matthew O'Loughlin.

The history of aviation and the pipeline industry shows that we learn from every accident. Indeed, the role of the NTSB, as exemplified here, is to analyze such accidents with the

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[20] Ex. CPSD-1 at 99 (CPSD/Stepanian).

[21] Ex. CPSD-1 at 24 (CPSD/Stepanian) ("At the time of the incident, the pressure on line 132 did not exceed the maximum pressure allowed by code."); Ex. CPSD-9 (NTSB Report) at 124.

[22] Ex. CPSD-1 at 99 (CPSD/Stepanian).

[23] *See* Ex. CPSD-9 (NTSB Report) at 124 ("The internal line pressure preceding the rupture did not exceed the PG&E maximum allowable operating pressure for Line 132 and would not have posed a safety hazard for a properly constructed pipe.").

[24] Ex. CPSD-1 at 126-61 (CPSD/Stepanian); Ex. CPSD-5 at 55-62 (CPSD/Stepanian); Ex. CPSD-168 (CPSD/Harpster); Ex. CPSD-170 (CPSD/Harpster).

knowledge of what occurred to develop lessons that may help to prevent such accidents in the future. In *The Signal and the Noise*, the author described the type of backward-looking analysis that is done after the fact:

> It is much easier *after* the event to sort the relevant from the irrelevant signals. After the event, of course, a signal is always crystal clear; we can now see what disaster it was signaling, since the disaster has occurred. But before the event it is obscure and pregnant with conflicting meanings. It comes to the observer embedded in an atmosphere of "noise," i.e., in the company of all sorts of information that is useless and irrelevant for predicting the particular disaster.[25]

The San Bruno accident was the product of PG&E's erroneous use of six unknown and unidentifiable pups in the 1956 construction of Segment 180. Unfortunately, without knowledge of the pups, any reasonable efforts to maintain the safety of the pipeline would not have prevented the accident.

PG&E's lack of knowledge does not excuse PG&E from responsibility for the accident or liability to the injured, and PG&E has never claimed otherwise. In this proceeding, however, the lack of awareness that the pups were in the ground, and having no record that defective pipe was installed (as would be expected), must frame the context in which PG&E's pre-accident conduct is evaluated and judged. PG&E's lack of knowledge of the pups cannot be disregarded, for instance, when asking whether PG&E's integrity management practices violated the law because the pups were not discovered before the accident. PG&E integrity management witness Kris Keas answered the question unequivocally:

> Mr. Malkin. Q: My question is given that there was no record and no one knew of the presence of the pup in Segment 180 with the missing interior seam weld until after the September 9th, 2010, accident, would any Integrity Management program that you are aware of have prevented that accident?
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> Witness Keas: A: No.[26]

Moreover, had PG&E known about the pups, it would not have done integrity management differently, or conducted a hydro test on Segment 180, or corrected its records from seamless

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[25] Nate Silver, *The Signal and the Noise*, Penguin Press (2012), at 418 (citing Roberta Wohlstetter, *Pearl Harbor: Warning and Decision*, Stanford Univ. Press (1962), at 387 [emphasis in original]).

[26] Joint R.T. 1210 (PG&E/Keas).

pipe to DSAW pipe, or taken any of the other actions CPSD asserts should have been taken before September 9, 2010 – it would have immediately cut out the pups and replaced them with properly manufactured pipe. PG&E witness David Harrison described it in plain terms:

> Mr. Foss: Q: Would they have, instead of doing that, would they have done pressure testing?
>
> Mr. Harrison: A: If they knew those welds were missing, those engineers would be screaming, and they would be yanking that pipe out of the ground.[27]

It is a hindsight judgment not supported by the facts for CPSD to assert that PG&E should have seen some document or taken some action that would have prevented this terrible accident, and that the failure to do so was a violation of law. Once the pups were installed in 1956, the evidence shows that there was nothing PG&E or any other pipeline operator would reasonably have done that would have prevented this accident.

The theory on which CPSD bases its claim that the accident was preventable relies on hindsight knowledge and is convoluted, to say the least. CPSD's theory[28] focuses on Segment 181 of Line 132, the segment adjacent to the one that failed. It requires PG&E to have identified high consequence areas (HCAs) before PHMSA promulgated its final integrity management rule defining HCAs and two months before the rule took effect. It goes on to hypothesize that, if PG&E had done that, it might have taken a series of actions on Segment 181 that might have led, fortuitously, to the discovery that PG&E's Geographic Information System (GIS) erroneously identified Segment 180 as seamless. Rather than simply correcting its GIS to reflect the pipe was DSAW, as records stated, PG&E might have hydro tested Segment 180. If PG&E had hydro tested Segment 180, it would have discovered the seam defect in the pup, and thereby have prevented the accident.

PG&E accepts responsibility for the Line 132 rupture and is a better company now and forever due to the lessons learned from this accident. PG&E cannot agree, however, that conduct that did not violate applicable regulations or laws when it occurred can be legitimately punished based on changed expectations, post-accident information or hindsight judgments.

Finding that PG&E complied with the law in all material respects will not be popular, but it is the only conclusion that is supported by the evidence. Finding that PG&E complied with the

[27] Joint R.T. 337-38 (PG&E/Harrison).

[28] Ex. CPSD-1 at 44-49 (CPSD/Stepanian).

law is not the same as concluding that PG&E was "best in class" or exemplary in its compliance. It is simply a recognition that the law set minimum safety standards and those standards did not prevent every accident. That is why the Commission has moved beyond the federal safety regulations and eliminated the grandfathering of older pipelines [29] – a safety action that PG&E has supported from the beginning of R.11-02-019 in both words and by its actions.

II. BACKGROUND (PROCEDURE/FACTS)

A. Factual Summary

1. The September 9, 2010 Accident

On September 9, 2010, three PG&E employees and one contractor were working on a scheduled clearance as part of a replacement project for the uninterruptable power supply (UPS) at the Milpitas Terminal. [30] The UPS system provides temporary power during a power outage where a short loss of power could impact station operations. [31] Before starting the work, the crew held a tailboard meeting to discuss the steps that needed to be performed. [32] Throughout the scheduled clearance, the crew updated Gas Control before taking steps that could affect Gas Control Operators' ability to monitor or control station equipment. [33]

At approximately 5:22 p.m., power was unexpectedly lost to devices at Milpitas Terminal being provided 24 Volt DC power from two power supplies, PS-A and PS- B. [34] This impacted pressure transmitters providing pressure control signals to the valve controllers. [35] The loss of pressure signal caused the regulating valve controllers to command the corresponding valves to open, as designed, resulting in an increase in gas pressure for outgoing transmission pipelines, including Line 132. [36] The redundant pressure limiting system, i.e., monitor valves, limited the

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[29] *See Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related RatemakingMechanisms,* D.11-06-017, 2011 Cal. PUC LEXIS 324 (2011).

[30] Ex. PG&E-1 at 8- 5 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 7 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 3.

[31] Ex. CPSD-1 at 80 (CPSD/Stepanian).

[32] Ex. PG&E-1 at 8-5, 8-8 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-9 (NTSB Report) at 54; Ex. CPSD-12 at 10.

[33] Ex. PG&E-40 at 1-2; Ex. CPSD-12 at 15-16.

[34] Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager); Joint R.T. 115 (PG&E/Kazimirsky).

[35] Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager).

[36] Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8, 9-13 (PG&E/Miesner); Ex. CPSD-1 at 87-88 (CPSD/Stepanian).

downstream pressure within Milpitas Terminal to approximately 396 psig and thereafter restored pressure in Milpitas Terminal to the monitor valve set point of 386 psig – both pressures below the established maximum allowable operating pressure (MAOP) of 400 psig on Line 132.[37]

Within one or two minutes of the power failure, Gas Control contacted Milpitas Terminal to talk to the technicians to understand what took place.[38] Gas Control worked with the technician at Milpitas Terminal to monitor pipeline pressures as well as manually position and monitor various valves.[39] The remainder of the team at Milpitas Terminal worked on troubleshooting and fixing the power problem.[40] Although the back-up monitor valves had caught the pressure increase, at approximately 5:52 p.m., Gas Control reduced the pressure set points of regulator valves at stations upstream from Milpitas Terminal to 370 psig as a further precaution.[41] At 6:11 p.m., Line 132 ruptured at Segment 180.[42] The pressure at the rupture location was approximately 386 psig, well below the 400 MAOP.[43]

PG&E began responding immediately upon becoming aware of an unidentified fire in the San Bruno area, which was within a few minutes after the rupture occurred.[44] Concord Dispatch, PG&E's gas dispatch center whose territory includes the Peninsula gas transmis sion system, first learned of a fire in San Bruno at 6:18 p.m., and contacted a PG&E field employee to ask whether he could see the fire.[45] Over the next few minutes, Concord Dispatch received calls from off-duty PG&E personnel reporting the fire.[46] Concord Dispatch contacted the on-duty Gas Service Representative (GSR) and directed him to respond to the site.[47] By 6:25 p.m., Concord Dispatch had notified the Peninsula Division on-call supervisor of the event, and at 6:27 p.m., Concord Dispatch notified PG&E Gas Control of the reports of the explosion.[48]

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[37] Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-13 to 9-14 (PG&E/Miesner); Ex. CPSD-1 at 90-91 (CPSD/Stepanian).

[38] Joint R.T. 116 (PG&E/Slibsager).

[39] Ex. PG&E-40 at 3-5.

[40] Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 87-88 (CPSD/Stepanian); Ex. CPSD-12 at 107.

[41] Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-40 at 4; Ex. CPSD-1 at 89 (CPSD/Stepanian).

[42] Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 7 (CPSD/Stepanian).

[43] Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-13 to 9-14 (PG&E/Miesner); Ex. CPSD-1 at 91 (CPSD/Stepanian).

[44] Ex. PG&E-40 at 6-9; R.T. 415-16 (PG&E/Bull); R.T. 349-50 (PG&E/Almario).

[45] Ex. CCSF-2 at 1.

[46] Ex. PG&E-40 at 6; Ex. CCSF-2 at 1; R.T. 351-53 (PG&E/Almario).

[47] Ex. CCSF-2 at 1.

[48] Ex. CCSF-2 at 1.

Power was also lost to other station devices at Milpitas Terminal during the power failure, which rendered a number of the SCADA data points for Milpitas Terminal inaccurate or unreadable, and resulted in numerous SCADA alarms being sent to Gas Control.[49] The first low-low pressure alarm from Martin Station, several miles downstream from the rupture, came in on the SCADA system at 6:15 p.m. [50] Gas system operators analyzed the numerous incoming SCADA alarms and related data as efficiently and accurately as possible. [51] At approximately 6:29 p.m., 14 minutes after the first low-low alarm and 2 minutes after first learning of the fire in San Bruno, Gas Control operators concluded that there likely had been a rupture on Line 132, and began contacting PG&E emergency response personnel.[52]

There was continual response by PG&E throughout the incident, including dispatching Gas Service Representatives (GSR), dispatching the Measurement & Control (M&C) personnel, coordinating on scene with the fire department, and identifying and closing valves to isolate the rupture.[53] After being contacted by Concord Dispatch at approximately 6:25 p.m., the Peninsula Division on-call supervisor called the Peninsula Division Transmission & Regulation (T&R) Supervisor and the M&C mechanics assigned to the area.[54] He instructed the mechanics to go to the Colma Yard to retrieve their trucks and equipment to shut the necessary valves on Line 132.[55] By 6:41 p.m., one supervisor and one GSR were at the scene communicating with the San Bruno Fire Department on-scene command center.[56] After retrieving their tools and crew truck from the Colma Yard, the responding M&C mechanics arrived at the upstream valve location at 7:20 p.m., closed the valve by 7:30 p.m., and then travelled to and closed two more valves downstream at approximately 7:45 p.m., isolating the rupture at the closest possible locations.[57]

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[49] Ex. CPSD-1 at 11 (CPSD/Stepanian).

[50] Ex. PG&E-1 at 9-9 (PG&E/Miesner); Ex. CPSD-1 at 108 (CPSD/Stepanian).

[51] Ex. PG&E-1 at 9-8 to 9-9 (PG&E/Miesner).

[52] Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-5 (Tab 8-1); Ex. PG&E-1 at 9-9 (PG&E/Miesner); Ex. PG&E-40 at 7-8; Joint R.T. 118 (PG&E/Slibsager).

[53] R.T. 415-16 (PG&E/Bull); R.T. 282, 381 (PG&E/Almario); Ex. PG&E-1 at 11-25 to 11-26 (PG&E/Bull); Ex. PG&E-1 at 10-6 (PG&E/Almario); Ex. PG&E-40 at 4-5; Ex. PG&E-1 at 11-28 (PG&E/Bull); R.T. 295 (PG&E/Almario).

[54] Ex. PG&E-40 at 6-7; R.T. 379-82 (PG&E/Almario).

[55] Ex. CPSD-13 at 10-11, 18-19, 22-23.

[56] Ex. CPSD-9 (NTSB Report) at 14; R.T. 285, 385-86 (PG&E/Almario).

[57] Ex. PG&E-40 at 11-13; Ex. CPSD-96 at 26-34; Ex. CPSD-1 at 12 (CPSD/Stepanian); R.T. 270-7 2
(PG&E/Almario).

2. Line 132 And Segment 180 Construction

In 1948, PG&E first constructed the section of Line 132 that runs through San Bruno.[58] PG&E ordered the pipe for that construction from Consolidated Western Steel Company, specifying 100,000 feet of 30-inch outside diameter, electric fusion welded, 0.375-inch wall thickness, 52,000 psig Specified Minimum Yield Strength (SMYS) steel pipe.[59] Prior to delivery to PG&E, most of the pipe lengths were to be double-wrapped to protect against external corrosion.[60] Consistent with API standards at that time, PG&E specified that no more than 5% of the order could consis t of "jointers" – two or more pieces of pipe joined together by welding at the manufacturer – and that any section of a jointer could not be shorter than 5 feet long.[61]

As additional quality assurance, PG&E engaged Moody Engineering Company to inspect the manufacturing process and testing of the Line 132 pipe at Consolidated Western's plant.[62] PG&E has not located Moody's report for that pipe purchase, but has located a Moody inspection report for pipe ordered from Consolidated Western approximately 3 months later for Line 153, the specifications for which were identical to the Line 132 pipe specifications.[63] The Moody report explained Consolidated Western's manufacturing process, and the quality assurance provided during the manufacturing process, as well as by Moody's inspection.[64] As the Moody report explained, the pipe was made using the "Union Melt" process, which involved double submerged arc welding, whereby the long seam was welded first on the outside of the pipe and then on the inside.[65] After fabrication, Consolidated Western subjected each joint of pipe to a mill test at a pressure of 90% of SMYS.[66]

In 1956, PG&E relocated a portion of Line 132 to accommodate a planned residential development in San Bruno.[67] The project called for the use of approximately 1,900 feet of the same type of 30-inch DSAW pipe used in the 1948 Line 132 project, the 1949 Line 153 project

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[58] Ex. PG&E-1 at 2-1 (PG&E/Harrison).
[59] Ex. PG&E-1 at 2-1 (PG&E/Harrison); Ex. PG&E-5 (Tabs 2-1, 2-2);*see* Ex. CPSD-9 (NTSB Report) at 28.
[60] Ex. PG&E-1 at 2-1 to 2-2 (PG&E/Harrison); Joint R.T. 537 (PG&E/Harrison).
[61] Ex. CPSD-9 (NTSB Report) at 28-29;*see also* Ex. PG&E-1 at 2-2 and 2-6 (PG&E/Harrison).
[62] Ex. PG&E-1 at 2-2 (PG&E/Harrison); Ex. PG&E-5 (Tab 2-1).
[63] Ex. PG&E-1 at 2-2 (PG&E/Harrison); Ex. PG&E-5 (Tab 2-2).
[64] Ex. PG&E-1 at 2-2 (PG&E/Harrison).
[65] Ex. PG&E-5 (Tab 2-3).
[66] Ex. PG&E-5 (Tab 2-3).
[67] Ex. CPSD-1 at 15 (CPSD/Stepanian).

and the 1953 Line 131 project. [68] PG&E completed the job using pipe previously ordered from Consolidated Western but not used. [69] Unknown to PG&E, one section of pipe installed in Segment 180 contained six short pieces of pipe (commonly called "pups"), [70] three of which did not contain the internal weld along the longitudinal seam that should have been present on DSAW pipe. [71] The pups were wrapped to protect against corrosion, though PG&E does not know whether the pups were delivered to the construction site wrapped or unwrapped.[72]

Segment 180 operated without incident for more than 50 years, but ruptured on September 9, 2010. [73] The pressure at the time and location of rupture was approximately 386 psig, below the established 400 psig MAOP. [74] The NTSB's metallurgical examination revealed that none of the pups met PG&E's specifications for 52,000 SMYS pipe, [75] and four of the pups did not meet any known specification for carrier pipe, including PG&E specifications. [76] There is no evidence that PG&E ever had actual knowledge of the existence of the pup sections or the missing welds, and no one has ever claimed that it did. [77] Properly constructed DSAW pipe that met PG&E and industry standards during its installation in 1956 would have withstood a pressure of 386 psig.[78]

3. Root Cause Of The Rupture

As discussed above, PG&E constructed Segment 180 using 30-inch diameter, 0.375-inch wall thickness, DSAW pipe. An approximately 23-foot long portion of Segment 180, however,

[68] Ex. PG&E-1 at 2-3 (PG&E/Harrison).
[69] Joint R.T. 378 (PG&E/Harrison).
[70] Ex. CPSD-1 at 16 (CPSD/Stepanian).
[71] Ex. CPSD-1 at 20 (CPSD/Stepanian).
[72] Joint R.T. 345, 411 (PG&E/Harrison).
[73] Ex. PG&E-1 at 2-4 (PG&E/Harrison); R.T. 1094 (PG&E/Caligiuri).
[74] Ex. CPSD-1 at 8 (CPSD/Stepanian).
[75] Ex. PG&E-1 at 3-5 to 3-6 (PG&E/Caligiuri); Ex. CPSD-1 at 19 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 27-28.
[76] Ex. CPSD-1 at 20 (CPSD/Stepanian); R.T. 1162 (PG&E/Caligiuri); Ex. CPSD-9 (NTSB Report) at 92.
[77] *See, e.g.*, Ex. PG&E-1 at 2-4 (PG&E/Harrison); Joint R.T. 368, 386 (PG&E/Harrison).
[78] Ex. PG&E-1 at 3-5 (PG&E/Caligiuri); Ex. CPSD-1 at 91 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 124; R.T. 1186-88 (PG&E/Caligiuri); Joint R.T. 422, 519 (PG&E/Harrison); Joint R.T. 188-89 (PG&E/Slibsager); Joint R.T. 190 (PG&E/Kazimirsky).

contained six short pups, [79] three of which were missing the interior longitudinal weld required for properly fabricated DSAW pipe.[80]

Dr. Robert Caligiuri, a pre-eminent metallurgist who has investigated many pipeline incidents, conducted a root cause analysis on the ruptured pipe sections. [81] Dr. Caligiuri concluded the missing interior weld on pup 1 was the originating factor in a chain of events that together resulted in the rupture on Segment 180. The rupture required the combination of (1) the missing interior weld on pup 1; (2) a ductile tear that initiated at the root of the existing longitudinal weld on pup 1; and (3) fatigue cracking that extended from the ductile tear and grew slowly over time. [82] Absent the missing interior longitudinal seam weld, the ductile tear would not have initiated; absent the missing weld and the ductile tear, the pipe would not have experienced fatigue crack growth anywhere near sufficient to lead to rupture.[83]

Dr. Caligiuri also analyzed the possible source of the ductile tear, without which fatigue crack growth to rupture would not have been possible. Based on burst pressure and metallurgical stress analyses, as well as the absence of any other plausible cause, Dr. Caligiuri concluded the ductile tear in the longitudinal seam on pup 1 was likely caused by a post-installation pressure test.[84] Dr. Caligiuri's metallurgical examination revealed that the initiation of the ductile tear preceded the fatigue crack growth. Dr. Caligiuri further determined that the magnitude of the single loading event required to cause the ductile tear was greater than the operational pressure fluctuations Segment 180 likely experienced over its lifetime. [85] Using mathematical models to calculate the pipe's burst pressure, Dr. Caligiuri concluded that a post -installation hydro test was the likely cause of the ductile tear in pup 1.[86]

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[79] Ex. PG&E-1 at 3-5 (PG&E/Caligiuri) ("The use of pups was a common industry practice for pipelines constructed in the late 1940s and early 1950s.").

[80] Ex. PG&E-1 at 3-5 (PG&E/Caligiuri).

[81] Ex. PG&E-1 at 3-1 to 3-17 (PG&E/Caligiuri).

[82] Ex. PG&E-1 at 3- 16 (PG&E/Caligiuri) ("Segment 180 operated safely between 1956 and 2010 because the missing interior seam weld and ductile tear were insufficient by themselves to cause the pipe to fail at the relatively low Line 132 operating pressures. The pipe rupture at 386 psig on September 9, 2010 occurred because of initiation and growth of fatigue cracking over a long period of time.").

[83] R.T. 1186-88 (PG&E/Caligiuri).

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

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

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

In 1956, when Segment 180 was installed, the pressure for a hydro test in a Class 2 location under ASA B31.1.8 (1955) would have been 1.25 times the pipe segment's MAOP.[87] In that case, Segment 180 would have been hydro tested to a pressure of 500 psig (or 1.25 x 400 psig). Because the area around Segment 180 was to be developed, it is also possible that Segment 180 would have been tested at the Class 3 level, or 1.4 times MAOP. [88] Applying the relevant mathematical models for calculating burst pressure, Dr. Caligiuri opined that Segment 180 would not have necessarily failed during a hydro test at either 500 or 560 psig, but test pressure would have been sufficient to constitute the single loading event that caused the ductile tear in pup 1. [89] In further support of his conclusion, Dr. Caligiuri pointed out that no other plausible cause of the ductile tear has ever been identified, and the NTSB has found his conclusion credible.[90]

4. Regulatory Background

In 1956, when PG&E constructed Segment 180, no state or federal regulations or mandatory industry standards governed pipeline safety. [91] Pipeline operators could write their own specifications for pipe or use industry standards from organizations such as the American Standards Association. [92] In 1952, the American Society of Mechanical Engineers (ASME) published its first integrated pipeline safety standard, called the American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems (ASME § B31.8). The American Society of Mechanical Engineers substantially revised the standard in 1955, and revised it thereafter throughout the years. Some companies such as PG&E started following the

[87] PG&E's Request for Official Notice, Ex. 5 (Ex. Records PG&E -47 (ASA B31.1.8), § 841.412(b) (1955)); Ex. CPSD-9 (NTSB Report) at 96 (noting that Segment 180 was in a Class 2 location in 1956).

[88] PG&E's Request for Official Notice, Ex. 5 (Ex. Records PG&E -47 (ASA B31.1.8), § 841.412(c) (1955)). The pipe materials used in Segment 180 (30" DSAW, 0.375" wt, 52,000 psig SMYS) were appr opriate for a Class 3 location. *See* Ex. CPSD-152.

[89] Ex. PG&E-1 at 3-11 to 3-15 (PG&E/Caligiuri); R.T. 1069-71 (PG&E/Caligiuri) ("I think that it certainly changes some of the margins you have in there. But it does not change my opinion that if they had tested this section of pipe to 560 psi, I believe it's possible that those three pups would have survived.").

[90] Ex. PG&E-1 at 3-14 (PG&E/Caligiuri); *see* R.T. 1084 (PG&E/Caligiuri).

[91] Ex. PG&E-1 at 2-4, 2-7 (PG&E/Harrison); Ex. CPSD-1 at 18 (CPSD/Stepanian).

[92] Ex. CPSD-1 at 18 (CPSD/Stepanian); Ex. PG&E-1 at 2-4 & 2-7 (PG&E/Harrison); Ex. PG&E-1 at 3-11 (PG&E/Caligiuri); Ex. CPSD-9 (NTSB Report) at 47.

nascent voluntary standard, although it was not more widely used until the mid to late 1960's and later.[93]

In 1961, the Commission began regulating the design, construction, operation and maintenance of natural gas pipelines in California under General Order 112. GO 112 incorporated the ASME B31.8 1958 edition with modifications. [94] ASME B31.8 thus applied to California operators not directly, but as incorporated with modifications through GO 112. GO 112 exempted existing facilities, such as Segment 180, from its requirements for initial design, construction and testing of pipe.[95]

The Natural Gas Pipeline Safety Act (NGPSA), enacted in August 1968, was the first comprehensive federal pipeline safety law.[96] In November 1968, the Secretary of Transportation adopted existing state regulations, including the Commission's, as interim standards, recognizing that a majority of the states utilized the standards contained in the 1968 edition of ASME B31.8.[97] In August 1970, the Office of Pipeline Safety (OPS), within the Department of Transportation, promulgated final rules at 49 C.F.R. Parts 191 and 192 establishing minimum federal safety standards, including reporting requirements (Part 191) and design, construction, operation, and maintenance requirements for natural gas pipeline facilities (Part 192). [98] Part 192 exempted existing facilities from "those provisions applicable to design, initial construction, initial inspection, and initial testing o f new pipelines."[99] 49 C.F.R. § 192.619(c) "grandfathered" existing pipelines such as Line 132, Segment 180, based on prior operating pressure history, and did not require existing pipelines to be pressure tested to establish the appropriate MAOP. [100] In promulgating Part 192, OPS recognized that "many operators [were] not familiar with the recommended standards of the B31.8 Code,"[101] stating as follows:

> Though Part 192 is based largely on the interim minimum Federal regulations, which were based primarily on recommended industry

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[93] 35 Fed. Reg. 13,247, 13,250 (Aug. 19, 1970); Joint R.T. 12, 23 (PG&E/Zurcher).

[94] Ex. CPSD-9 (NTSB Report) at 34; *Investigation into the Need of a General Order, etc.,* Decision No. 61269 (1960) (adopting GO 112), § 107.2.

[95] *Investigation into the Need of a General Order, etc.,*Decision No. 61269 (1960) (adopting GO 112), § 104.3.

[96] Pub. L. 90-481, 82 Stat. 720 (1968).

[97] 33 Fed. Reg. 16,500, 16,500-01 (Nov. 13, 1968).

[98] *See generally*, 35 Fed. Reg. 13,247 (Aug. 19, 1970)

[99] 35 Fed. Reg. at 13,248.

[100] 35 Fed. Reg. at 13,273; Ex. CPSD-9 (NTSB Report) at 34-35.

[101] 35 Fed. Reg. at 13,250.

> standards, we have found that many operators are not familiar with the recommended standards of the B31.8 Code. From investigations of accidents and the comments on our notices of proposed rulemaking, we know that a wide range of operators – large and small, privately owned and municipally-owned – are not familiar with either the Act or the interim regulations.[102]

Effective April 30, 1971, the Commission adopted GO 112-C, incorporating the 1970 federal pipeline regulations, 49 C.F.R. Part 192, in their entirety, and deleting the references to ASME B31.8.[103]

In 1994, Congress merged the NGPSA and the Hazardous Liquid Pipeline Safety Act (HLPSA) under the Pipeline Safety Act (PSA).[104]

In 1995, the Commission adopted GO 112-E, which automatically incorporated all revisions to the federal regulations by reference. GO 112-E remains the primary GO governing gas transmission pipeline safety in California.

In response to the Bellevue, Washington and Carlsbad, New Mexico pipeline accidents, in 2002, Congress enacted the Pipeline Safety Improvement Act. That act established integrity management requirements for gas transmission pipelines in high consequence areas.[105] Congress also created PHMSA over OPS to focus on safety as its highest priority.[106] Effective February 14, 2004, PHMSA promulgated the first integrity management regulations at 49 C.F.R. Part 192, Subpart O.[107]

B. San Bruno OII Procedural History

1. The Basis And Scope Of The OII

On January 12, 2012, the Commission issued Order Instituting Investigation I.12-01-007 (San Bruno OII).[108] On the same date, CPSD issued its Incident Investigation Report related to the Line 132 pipeline rupture.[109] The CPSD report alleged that the Line 132 rupture was caused

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[102] 35 Fed. Reg. at 13,250.
[103] Decision No. 78,513 (adopting GO 112-C).
[104] Pub. L. No. 103-272, 108 Stat. 1301-29 (1994)
[105] Pub. L. No. 107-355, 116 Stat. 2985 (2002)
[106] Pub. L. No. 108-426, 118 Stat. 2423 (2004).
[107] Ex. CPSD-9 (NTSB Report) at 69.
[108] I. 12-01-007.
[109] Ex. CPSD-1 (CPSD/Stepanian).

by PG&E's failure to comply with various federal and state pipeline safety regulations and industry standards.[110] The Commission instituted this proceeding to evaluate the findings in the CPSD report and determine whether PG&E and its officers, directors, and managers violated any regulations and standards in connection with the San Bruno accident.[111] If supported by the evidence, the Commission stated that it would consider ordering "daily fines for the full duration of any such violations."[112]

The Commission also authorized the Commission staff to engage in discovery first to complete its testimony, stating, "[s]taff need only respond to discovery requests after completion of its direct testimony to allow staff to complete its investigation."[113] By Commission Order dated September 25, 2012, the Commission granted CPSD's request to file a single coordinated brief regarding fines and remedies in proceedings I.12-01-007, I.11-02-016 (Records OII), I.11-11-009 (Class Location OII).[114]

2. The Parties To The Proceeding

The San Bruno OII named CPSD as a party and PG&E as respondent. The Commission invited the active participation of intervenors and several parties intervened.[115] The Division of Ratepayer Advocates (DRA), the City and County of San Francisco (CCSF), and the City of San Bruno were granted party status at the Prehearing Conference on February 14, 2012, and confirmed in the March 13, 2012 Scoping Memo.[116] The Commission granted The Utility Reform Network (TURN) party status on February 15, 2012 via electronic ruling, and affirmed it in the Scoping Memo. TURN gave notice of its intent to seek intervenor compensation on March 15, 2012.

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[110] Ex. CPSD-1 at 162-63 (CPSD/Stepanian).

[111] I.12-01-007 at 2.

[112] I.12-01-007 at 9.

[113] I.12-01-007 at 12.

[114] Administrative Law Judges' Ruling Granting Motions of Consumer Protection and Safety Division for Leave to Serve Additional Prepared Testimony and for Permission to File a Single Coordinated Brief Regarding Fines and Remedies and Notice of Hearing (September 25, 2012) ("September 25, 2012 Ruling").

[115] I.12-01-007 at 9-10.

[116] Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling and Notice of Hearing (March 13, 2012).

3. CPSD's Testimony

On January 12, 2012, CPSD issued its Incident Investigation Report, which attached the December 30, 2011 Overland Consulting (Overland) Focused Audit of PG&E Gas Transmission Pipeline Safety-Related Expenditures ("Overland Report"). On March 16, 2012, CPSD served the testimony of Raffy Stepanian, adopting the CPSD's Incident Investigation Report and supporting documents as his testimony. On August 20, 2012, CPSD served the rebuttal testimony of Raffy Stepanian, and the rebuttal testimony of Gary Harpster in response to the testimony of Matthew P. O'Loughlin responding to the Overland Report. On September 19, 2012, CPSD served an errata for the December 30, 2011 Overland Report, and an errata and a corrected version of Harpster's rebuttal testimony. At the evidentiary hearing, PG&E waived cross-examination of Mr. Stepanian, and his written testimony was admitted into evidence.

4. Intervenors' Testimony

CCSF, the City of San Bruno, and TURN each submitted intervenor testimony. CCSF submitted the testimony of John Gawronski on April 23, 2012. The City of San Bruno submitted the testimony of Mayor Jim Ruane on April 23, 2012. TURN submitted the testimony of Marce l Hawiger on April 24, 2012. At the evidentiary hearing, PG&E waived cross-examination of Messrs. Gawronski, Hawiger, and Ruane, and their written testimony was admitted into evidence.[117] DRA did not serve testimony.

5. PG&E's Testimony

PG&E served its testimony responding to the written testimony from CPSD and the intervening parties on June 26, 2012.[118] PG&E's responsive testimony included the testimony of highly-respected industry experts: John Zurcher, a long-time industry participant and co-drafter of the federal integrity management regulations, testified regarding the relevance of historic records to gas engineering and integrity management decisions, and integrity management practices and regulation generally.[119] Robert Caligiuri, Ph.D., a professional metallurgical engineer who has investigated over 25 failures involving pipelines, testified regarding the root

[117] Ex. CCSF-1 (CCSF/Gawronski); Ex. CSB-1 (CSB/Ruane); Ex. TURN-1 (TURN/Hawiger).

[118] Ex. PG&E-1 (multiple witnesses). In January, 2013, PG&E submitted revised testimony for Chapters 1, 4, and 13. Exs. PG&E-1a (PG&E/Yura), PG&E-1b (PG&E/Yura), & PG&E-1c (PG&E/Keas).

[119] Ex. PG&E-1 at 5-1 to 5-17 (PG&E/Zurcher); Joint R.T. 2-81, 642-889 (PG&E/Zurcher).

cause of the Line 132 rupture, including the potential that a post-installation hydro test on Segment 180 initiated the ductile tear that ultimately grew to rupture. [120] John Kiefner, widely considered the preeminent engineering expert regarding manufacturing and construction defects in pipelines, testified regarding the relevance of cyclic fatigue on natural gas pipelines. [121] Thomas Miesner, a long-time pipeline operator and former director at several pipeline companies who now teaches various operational subjects to the pipeline industry, testified regarding PG&E's SCADA system and the local pressure control system at the Milpitas Terminal. [122] David Bull, a former associate staff member of PHMSA's Office of Training and Qualifications who has years of experience instructing gas operators on emergency response regulations, testified regarding PG&E's emergency plan compliance with gas safety regulations. [123] Joseph Martinelli, also a long-time industry participant and consultant, testified regarding budgeting and spending with respect to Line 132. [124] And Matthew O'Loughlin, an industry expert on utility ratemaking, testified regarding PG&E's actual and imputed adopted O&M and capital expenditures in the years prior to September 9, 2010.[125]

PG&E also submitted the testimony of several Company witnesses. David Harrison testified regarding Line 132 and Segment 180 construction and recordkeeping. [126] Kris Keas testified regarding PG&E's integrity management program. [127] Mark Kazimirsky and Keith Slibsager testified jointly regarding PG&E's SCADA system, Gas Control operations, and the events and control systems at Milpitas Terminal. [128] Kathy Oceguera testified regarding improvements to PG&E's incident-related drug and alcohol testing procedure. [129] Jonathan Seager testified regarding the Brentwood alternate Gas Control facility security camera. [130] Benedict Almario testified regarding PG&E's emergency response to the San Bruno accident.[131]

[120] Ex. PG&E-1 at 3-1 to 3-17 (PG&E/Caligiuri); R.T. 1051-1205 (PG&E/Caligiuri).

[121] Ex. PG&E-1 at 6-1 to 6-8 (PG&E/Kiefner); R.T. 684-725, 730-839 (PG&E/Kiefner).

[122] Ex. PG&E-1 at 9-1 to 9-14 (PG&E/Miesner); R.T. 843-65 (PG&E/Miesner).

[123] Ex. PG&E-1 at 11-1 to 11-29 (PG&E/Bull); R.T. 411-31 (PG&E/Bull).

[124] Ex. PG&E-1 at 12-1 to 12-4 (PG&E/Martinelli); R.T. 478-506 (PG&E/Martinelli).

[125] Ex. PG&E-10 & Ex. PG&E-11 (PG&E/O'Loughlin); R.T. 535682 (PG&E/O'Loughlin).

[126] Ex. PG&E-1 at 2-1 to 2-11, 7-1 to 7-3 (PG&E/Harrison); Joint R.T. 215-607 (PG&E/Harrison).

[127] Ex. PG&E-1c at 4-1 to 4-40 (PG&E/Keas); Joint R.T. 905-1245 (PG&E/Keas).

[128] Ex. PG&E-1 at 8-1 to 8-23 (PG&E/Kazimirsky/Slibsager); Joint R.T. 83-214 (PG&E/Kazimirsky/Slibsager).

[129] Ex. PG&E-1 at 8-23 to 8-25 (PG&E/Oceguera); R.T. 247-63 (PG&E/Oceguera).

[130] Ex. PG&E-1 at 7-3 (PG&E/Seager). Mr. Seager was only cross-examined at hearings in the Records OII.

[131] Ex. PG&E-1 at 10-1 to 10-6 (PG&E/Almario); R.T. 265-410 (PG&E/Almario).

Joel Dickson testified regarding PG&E's emergency response plans and improvement initiatives subsequent to the Line 132 accident. [132] And Jane Yura testified regarding PG&E's post -San Bruno actions improving safety and operational excellence.[133]

6. The Evidentiary Hearings

Evidentiary hearings began on September 24, 2012, before the assigned Administrative Law Judge (ALJ), Mark Wetzell. The September 24, 2012 hearing was a joint hearing in this and the Class Location OII (I.11-11-009) on the issue of PG&E's use of assumed SMYS values. The hearings were initially scheduled to conclude on October 19, 2012. The Commission suspended evidentiary hearings and the procedural schedule on October 11, 2012, to facilitate negotiations toward a stipulated outcome. [134] On November 2, 2012, the Commission granted CPSD's requests on behalf of all the parties that the procedural schedule be modified a second time to allow the parties further time to attempt to reach a stipulated outcome, and directed that hearings would resume on November 26, 2012.[135]

On November 19, 2012, the Commission issued a ruling granting in part, and denying in part, the parties' motion for extension of time in the proceedings in order to facilitate negotiations.[136] The Commission extended the schedule for evidentiary hearings and submission of financial analysis testimony, and put the parties on notice that no further extensions would be granted absent the parties reaching an agreement in principle. Hearings resumed on January 8, 2013, and concluded on January 17, 2013. Several hearing days were joint hearings in both this and the Records OII (I.11-012-016).

As directed by ALJ Wetzell, on January 15, 2013, PG&E submitted its objection and motion to exclude portions of CPSD's rebuttal testimony. On February 5, 2013, TURN, the City of San Bruno, and the DRA filed a motion to exclude Exhibit PG&E-43 and related examination.

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[132] Ex. PG&E-1 at 10-6 to 10-11 (PG&E/Dickson); R.T. 431-74 (PG&E/Dickson).

[133] Ex. PG&E-1a at 1-1 to 1-5; 13-1 to 13-16 (PG&E/Yura); R.T. 875-1044 (PG&E/Yura).

[134] Administrative Law Judges' Wetzell and Yip-Kikugawa Ruling Regarding Motion of Consumer Protection and Safety Division to Suspend Proceedings in Order to Facilitate Negotiations Toward a Stipulated Outcome and Notice of Revised Hearing Schedule (October 11, 2012).

[135] Administrative Law Judge's Ruling Affirming Resumption of Proceedings and Modifying Procedural Schedule (November 2, 2012).

[136] Assigned Commissioners' Ruling Granting, in Part, and Denying, in Part, Motion for Extension of Time in Proceedings in Order to Facilitate Negotiations Toward a Stipulated Outcome (November 19, 2012).

On February 13, 2013, the ALJ issued a ruling resolving both motions, excluding Section IX.A of Exhibit CPSD-5 and Exhibit PG&E-43.[137]

7. Related OII And Rulemaking Proceedings[138]

The Commission initiated multiple proceedings following the San Bruno accident. On February 24, 2011, the Commission started an investigation into whether PG&E violated applicable rules or requirements pertaining to safety recordkeeping for all of its gas transmission pipelines.[139] The same day, the Commission initiated a rulemaking proceeding to consider a "new model of natural gas pipeline safety regulation applicable to all California pipelines."[140] On November 10, 2011, the Commission instituted a proceeding to determine whether PG&E's natural gas transmission pipeline system was safely operated in areas of greater population density or other areas identified as High Consequence Areas (HCAs).[141] The OIIs are not consolidated. Because the investigations are closely related, however, the ALJs granted CPSD's request for a coordinated brief on fines and remedies.[142]

As relevant here, the Safety Rulemaking concluded on December 20, 2012, with the Commission's approval of PG&E's Pipeline Safety Enhancement Plan and determination of the sharing of the costs of that plan between shareholders and customers.[143]

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137 Administrative Law Judge's Ruling on (1) PG&E's Objection and Motion to Exclude Portions of CPSD's Rebuttal Testimony and (2) Joint Motion to Exclude Exhibit PG&E-43 and Related Examination (February 13, 2013).

138 The proceedings the Commission initiated after the San Bruno accident relate and overlap to a significant extent. The San Bruno OII and the Records OII, in particular, proceeded on parallel courses and resulted in several joint evidentiary hearings, joint witnesses and joint exhibits. The Commission ordered coordinated briefing among the San Bruno OII, the Records OII and the Class Location OII with respect to fines and remedies. Given the inter-relation, PG&E cites evidence from the Records OII in this brief. PG&E is concurrently filing a Request for Official Notice, asking that the Commission take official notice of specific exhibits and testimony from the Records OII. *See* PG&E's Request for Official Notice, filed March 11, 2013.

139 I.11-012-016 (filed February 24, 2011).

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

141 I.11-11-009 (filed November 10, 2011)

142 September 25, 2012 Ruling.

143 *Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms*, D. 12-12-030, 2012 Cal. PUC LEXIS 600 (December 20, 2012).

8. Organization And Designation Of Exhibits And Hearing Materials

Over 400 exhibits were admitted into evi dence during the hearings. For the ALJ's convenience, PG&E attaches as Appendix C an Exhibit Index that identifies each party's exhibits by exhibit number, including joint exhibits admitted in the combined hearings. The Exhibit Index also lists the exhibits received into evidence in the Records OII to which PG&E cites in its opening brief. PG&E is submitting separately a Request for Official Notice, which identifies and provides a copy of each document for which PG&E requests official notice.

III. LEGAL ISSUES OF GENERAL APPLICABILITY

Two legal issues impact this proceeding as a whole. The first is the appropriate standard of proof the Commission should apply. There is no question that CPSD bears the burden of proof for every violation it asserts. The standard of proof to which CPSD should be held is not as clear cut. Though the Commission usually applies a preponderance of the evidence standard in enforcement proceedings, the circumstances here warrant the higher standard of clear and convincing evidence. The scope of the proceeding, the broad sanctions the Commission has stated it may impose, and the lack of rigor in the applied legal standards and violations all point towards the need to apply a higher threshold of proof.

The second issue is CPSD's rel iance on Public Utilities Code Section 451 as a free-floating safety law to be applied after the fact. CPSD's use of Section 451 to allege safety violations going back several decades is both inconsistent with the statutory scheme and contrary to fundamental due process requirements.[144]

A. The Commission Should Apply The Clear And Convincing Evidence Standard

In certain civil cases of exceptional importance, "clear and convincing" evidence is constitutionally required.[145] These high-stakes cases require more than the usual preponderance of the evidence standard because of society's demand for a greater "degree of confidence . . . in the correctness of [the adjudicator's] factual conclusions."[146] Many of these cases involve the threatened deprivation of a liberty interest, such as civil commitment, but others do not.

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[144] *See* Cal. Const., art. I, § 7.

[145] *See, e.g., In re Angelica P.*, 28 Cal. 3d 908, 919 (1981).

[146] *Id.* (internal quotation marks omitted).

California courts have held, for example, that the "clear and convincing" standard applies to professional license suspension or revocation proceedings, even where the threatened sanction is only a modest fine. *See, e.g., Hughes v. Bd. of Architectural Examiners*, 17 Cal. 4th 763, 789 n.9 (1998) ("[P]rocedural due process of law requires a regulatory board or agency to prove the allegations of an accusation filed against a licensee by clear and convincing evidence rather than merely by a preponderance of the evidence."); *Grubb v. Department of Real Estate*, 194 Cal. App. 4th 1494, 1502 (2011) ("[U]nder the California Constitution, the suspension or revocation of a professional license must be based on misconduct proven by clear and convincing evidence.").

This proceeding, as all parties recognize, is exceptionally important to PG&E, the Commission, the intervening parties and the public generally. The stakes are greater than those in the usual Commission enforcement proceeding.[147] The Commission made this clear at the outset when it stated its readiness to impose "daily fines for the full duration of any such violations, even if this encompasses a lengthy period of time."[148] Given the importance of this proceeding, CPSD should be required to prove each of its asserted violations by clear and convincing evidence.

In fact, this proceeding presents a more compelling case for requiring clear and convincing evidence than *Grubb*. There, respondents were accused of making a reckless misrepresentation regarding a real estate transaction.[149] The Real Estate Commissioner ordered a 30-day suspension of their licenses or a $3,000 fine in lieu of suspension.[150] The court directed the Commissioner to set aside his order because the alleged misconduct was not established by clear and convincing evidence.[151] Here, PG&E faces potential penalties far more severe than the threatened deprivation in *Grubb* – a 30-day license suspension or $3,000 fine. As noted, the Commission has signaled its willingness to impose "daily fines for the full duration of any such violations, even if this encompasses a lengthy period of time."[152] Indeed, CPSD has alleged

[147] R.T. 39-52 (parties' opening statements).
[148] I.12-02-007 at 9.
[149] 194 Cal. App. 4th at 1500.
[150] *Id.* at 1501.
[151] *Id.* at 1506.
[152] I.12-01-007 at 9.

continuing violations spanning more than 50 years. [153] Should the Commission find even one such violation, PG&E will be subject to a *minimum* penalty of nearly $10 million; the maximum could approach $140 million. [154] If clear and convincing evidence was necessary to justify the deprivation in *Grubb*, it is all the more necessary here.

This case also parallels the license suspension cases in another respect. It is not just about penalties or fines. The Commission stated it may impose potentially extensive remedial relief, including some or all of the 41 separate recommendations contained in CPSD's Report:[155]

> We emphasize that the Commission's remedial powers are not limited to its authority to impose civil penalties. Pursuant to Public Utilities Code Section 761, if the Commission finds that PG&E's maintenance or operations practices were unsafe, unreasonable, improper, or insufficient, we may consider ordering PG&E to change or improve its maintenance, operations, or construction standards for gas pipelines, in order to ensure system-wide safety and reliability. We place PG&E on notice that the Commission may consider ordering PG&E to implement the recommendations made in CPSD's Report, in order to improve and ensure system-wide safety and reliability.[156]

The prospect of remedial sanctions takes this case out of the category of a pure monetary penalty case and into a category of cases, like the professional licensing cases, that involve potentially more significant non-monetary sanctions.

Although the Commission has previously rejected the argument that clear and convincing evidence is required in every enforcement proceeding involving potentially substantial penalties, the decision in which it did so supports application of that heightened standard in this case. *See Investigation of Qwest Commc'ns Corp.*, D.03-01-087, 2003 Cal. PUC LEXIS 67, at *13-14 ("*Qwest*"). In *Qwest*, the Commission rejected an analogy between the statutory penalties authorized by Section 2107 and punitive damages, which by statute require "clear and

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[153] Ex. CPSD-1 at 3-4, 162-63 (CPSD/Stepanian).

[154] Pub. Utilities Code § 2107. The applicable fine range is determined by the statutory fines available at the time of the violation. *See Marin Telemanagement Corp. v. Pacific Bell*, D. 95-01-044, 1995 Cal. PUC LEXIS 43, at *33-34 & n.34. From 1930 through 1993, the authorized fine range under Section 2107 was $500-$2000 per violation per day. From 1994 through 2010, the minimum fine remained $500 and the maximum fine increased to $20,000. *See id.*

[155] Ex. CPSD-1 at 164-71 (CPSD/Stepanian). Among the actions CPSD recommends is that PG&E spend approximately $430 million of shareholder funds on its gas transmission and storage operations before being permitted to recover funds from ratepayers. Ex. CPSD-1 at 168 (CPSD/Stepanian).

[156] I.12-01-007 at 10.

convincing evidence of oppression, fraud, or malice."[157] The Commission concluded that the higher evidentiary standard for punitive damages is unwarranted for Section 2107 penalties because their amount "is determined by the Legislature (within a range, and capped), whereas the amount of punitive damages is determined by a fact finder (judge or jury)."[158] The Commission emphasized that the magnitude of the total fine in *Qwest*, $20.34 million, was driven by the large number of individual violations (3,581 individual slamming violations and 4,871 cramming violations) each arising from specific instances of customer complaints. *See* 2003 Cal. PUC LEXIS 67 at *15 ("The main reason the fine is so large is because the number of violations established is large."). Thus, in a real sense, the Legislature, and not the Commission, had set the minimum and maximum fine per violation for *each* of the offenses.

Unlike in *Qwest*, CPSD has not asserted thousands of discrete violations, each subject to the legislative cap. It has asserted multiple "continuing" violations which, if proven and aggregated together, would afford the Commission discretion far beyond the statutory range that would apply to a single violation that occurred on a single day. As a result, and if the Commission adopts CPSD's expansive view of what constitutes a continuing violation, this is not a case where Section 2107's penalty cap meaningfully constrains the Commission's discretion or defines the penalty range. The extraordinary time span of CPSD's alleged violations, and its aggressive use of Section 2108, means discretion has effectively been delegated to the Commission to impose a fine that is almost without limit. As a practical matter, this discretion is as great as the discretion any jury may have to return a large punitive damages award.

For all of these reasons, the Commission should hold CPSD to prove its alleged violations by clear and convincing evidence. To meet that burden, CPSD must establish each asserted violation by evidence "'so clear as to leave no substantial doubt'; [and] 'sufficiently strong to command the unhesitating assent of every reasonable mind.'"[159]

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[157] *Id.* at *13.
[158] *Id.*
[159] *In re Angelica P.*, 28 Cal. 3d at 919 (quoting *Sheehan v. Sullivan*, 126 Cal. 189, 193 (1899)).

B. Public Utilities Code Section 451 Is Not, And Cannot Constitutionally Be, A Safety Regulation

1. Section 451 Is Not A Source Of Pipeline Safety Requirements

CPSD relies on Public Utilities Code Section 451 to allege several safety violations.[160] But Section 451 is a ratemaking provision. It cannot serve as a free-floating source of pipeline safety requirements.

A code section must be construed "'in the context of the statute as a whole and the overall statutory scheme.'" *Smith v. Superior Court*, 39 Cal. 4th 77, 83 (2006) (quoting *People v. Canty*, 32 Cal. 4th 1266, 1276 (2004). "[I]t is well established that 'chapter and section headings [of an act] may properly be considered in determining legislative intent . . . and are entitled to considerable weight.'" *People v. Hull*, 1 Cal. 4th 266, 272 (1991) (quoting *Am. Fed'n of Teachers v. Bd. of Educ.*, 107 Cal. App. 3d 829, 836 (1980)). Section 451 appears in Chapter 3, Article 1 of the Public Utilities Act, under the heading "RATES." All the substantive provisions of that article address ratemaking. *See generally* Pub. Util. Code §§ 451–467. Chapter 4 of the Act, entitled "REGULATION OF PUBLIC UTILITIES," contains the statutory provisions that confer authority on the Commission to promulgate and enforce safety standards. *See,* Art. 3 ("Equipment, Practices, and Facilities") & Pub. Util. Code §§ 761 & 768. The statutory structure, reflected in its headings, weighs "considerabl[y]" against interpreting Section 451 as a free-floating safety standard.[redacted] *Hull*, 1 Cal. 4th at 272.

The text of Section 451 confirms that it does not impose a general safety obligation on public utilities. Its only reference to "safety" is buried in one dependent clause within a multi-paragraph provision. As codified in Article 1 ("RATES") of the Public Utilities Code, Section 451 reads:

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[160] Ex. CPSD-1 at 3-4, 162 (CPSD/Stepanian); Ex. CPSD-5 at 1-3 (CPSD/Stepanian).

[redacted]

§ 451. **Just and reasonable charges, service, and rules**

> All charges demanded or received by any public utility, or by any two or more public utilities , for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.
>
> Every public utility shall furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.
>
> All rules made by a public utility affecting or pertaining to its charges or service to the public shall be just and reasonable.

The first paragraph of Section 451 mandates that a utility charge just and reasonable rates. The second paragraph specifies what level of service a utility must furnish in exchange for receiving just and reasonable rates: it must furnish adequate, efficient, just and reasonable service, of which "safety" is just one element. The last paragraph specifies that a utility's rules affecting charges or services must similarly be just and reasonable.

It has long been settled that Section 451, by its terms, requires a balancing of several considerations. Most basically, Section 451 requires a balancing of rates against the proper level of service. *See Pacific Telephone and Telegraph Co. v. Public Util. Comm'n* , 34 Cal. 2d 822, 826 (1950) (defining the Commission's primary purpose as "insur[ing] the public adequate service at reasonable rates without discrimination"); *see also Application of Pacific Gas and Electric Company, etc.,* D.00-02-046, 2000 Cal. PUC LEXIS 239, at *32 ("Our charge is to ensure that PG&E provides adequate service at just and reasonable rates") . As the Commission has long maintained, in determining the proper level of service, it must evaluate and balance what is adequate, efficient, just and reasonable. *See Corona City Council v. Southern California Gas Co.,* D.92-08-038, 1992 Cal. PUC LEXIS 5 63, at *28 ("SoCalGas argues that PU Code § 451 requires a balancing of the four factors: adequate, just, reasonable and efficient. We agree with SoCalGas that to determine the proper level of utility service we must carefully balance all four factors."). In achieving this balance, the safety of the public is one important consideration – as are the health, comfort and convenience of the public and others. In setting just and reasonable rates, the Commission has broad latitude to adopt the safety standards that are consistent with the rates. To construe Section 451 to create stand-alone, free-floating safety rules, however, requires the Commission to extract one consideration (safety) from all those Section 451 requires to be evaluated and balanced in setting just and reasonable rates. That construction fails to read Section 451 as a whole or in context.

CPSD contends that Section 451 incorporates the expectation that gas utilities will use "good utility safety practices" when managing their gas systems, and that actions contrary to that standard may be deemed violations of law.[162] CPSD explains:

> Section 451, which has been in effect since 1909 (half a century prior to the installation of Segment 180), is a broad and general requirement for utilities to create and follow safe operating practices. Section 451 is not prescriptive in the specific manner in which its obligations must be met. Without such specifics and because no set of regulations can cover every single possible unsafe condition, one looks to the industry standards and guidelines for guidance.[163]

In a nutshell, CPSD contends Section 451 prohibits whatever actions CPSD deems – after the fact – fall short of "good utility safety practices."[164]

To accept CPSD's contention that Section 451 mandates (and has always mandated) a "good utility safety practices" standard would impermissibly render superfluous entire provisions of the Public Utilities Code and every Commission regulation that requires any safety measure of any kind. *See Klein v. United States*, 50 Cal. 4th 68, 80 (2010) (describing the rule of statutory construction that "courts must strive to give meaning to every word in a statute and to avoid constructions that render words, phrases, or clauses superfluous."). Section 768, for instance, authorizes the Commission to prescribe that utilities implement specified safety measures:

> The commission may, after a hearing, require every public utility to construct, maintain, and operate its line, plant, system, equipment, apparatus, tracks, and premises in a manner so as to promote and safeguard the health and safety of its employees, passengers, customers, and the public. The commission may prescribe, among other things, the installation, use, maintenance, and operation of appropriate safety or other devices or appliances,

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162 *See* CPSD-5 at 1-3 (CPSD/Stepanian).

163 Ex. CPSD-5 at 1 (CPSD/Stepanian).

164 As discussed in more detail below, CPSD compounds its improper use of Section 451 by articulating three distinct and inconsistent standards that it claims Section 451 imposes.

> including interlocking and other protective devices at grade crossings or junctions and block or other systems of signaling. The commission may establish uniform or other standards of construction and equipment, and require the performance of any other act which the health or safety of its employees, passengers, customers, or the public may demand.

When adopting GO 112 in December 1960, the Commission relied on its authority under Section 768, not Section 451. [165] Pursuant to Section 768, the Commission adopted, as a Commission rule, a modified version of the existing ASA B31.8 standard. [166] Yet CPSD maintains, even before the Commission adopted this standard, Section 451 already obligated California utilities to adhere to it because B31.8 reflected the "good utility safety practices" standard.[167] If, as CPSD contends, the ASA B31.8 standard already applied to California utilities through Section 451, then the Commission's adoption of GO 112 in 1960 amounted to a redundant rulemaking exercise.[168]

The Legislature would have spoken with a great deal more clarity had it intended to impose its own "good utility safety practices" standard on every public utility in the state, distinct from the Commission's explicit safety rulemaking authority and the rules promulgated thereunder. As the U.S. Supreme Court explained in an analogous context, "Congress, we have held, does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions – it does not, one might say, hide elephants in mouseholes." *Whitman v. American Trucking Assoc., Inc.*, 531 U.S. 457, 468 (2001). CPSD's application of "good utility safety practices" is essentially a free-floating strict liability standard to be applied after the fact – if a pipeline accident occurs, by definition the pipeline was not safe and CPSD can assert that the utility failed in its Section 451 duty to promote safety. The specific safety hazard may have been unforeseeable, but in CPSD's mind that is all the more reason to apply Section 451: "It is recognized that no code of safety rules, no matter how carefully and well prepared can be relied

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[165] *Investigation into the Need of a General Order, etc.,* Decision No. 61269 (1960).

[166] Ex. CPSD-5 at 1-2 (CPSD/Stepanian); [redacted]

[167] Ex. CPSD-5 at 1-3 (CPSD/Stepanian) (combining Section 451 and the existing ASA standards into "good utility safety practices").

[168] Other parts of the Public Utilities Code would be similarly impacted. Public Utilities Code § 2794, for example, requires a gas or electric system acceptable for transfer to meet "the commission's general orders" regarding safety and reliability. The Legislature did not specify that the system must also meet an open-ended "good utility safety" standard CPSD has grafted into Section 451.

upon to guarantee complete freedom from accidents."[169] For CPSD, Section 451 provides a guarantee that any action it deems unsafe can be cause for an enforcement action: "Any unsafe condition or a violation of a safety practice may be a violation of Section 451."[170] The Legislature could have imposed strict liability on utilities had it wanted to do so, but it would be extraordinary to conclude that it prescribed such strong medicine by making a passing reference to safety in a ratemaking provision.

[redacted] In the San Bruno OII, CPSD relies on an appellate court decision, *Pacific Bell Wireless, LLC (Cingular) v. Public Utilities Comm'n*, 140 Cal. App. 4th 718 (2006), which PG&E addresses below.

Far from supporting CPSD, *Carey* casts doubt on CPSD's use of Section 451 in these proceedings. *Carey* arose out of an explosion at a multi-unit apartment building. The Commission found PG&E had violated Section 451 by following an internal company policy authorizing fumigation contractors to terminate natural gas service as part of fumigation projects. The Commission rejected PG&E's void for vagueness due process challenge to Section 451, concluding that the terms "reasonable service, instrumentalities, equipment and facilities" were not without definition. The Commission concluded that PG&E had fair notice of what was "reasonable" because reasonableness could be determined with reference to "a definition, standard or common understanding among utilities."

Carey is unique in that it is one of only two adjudicated enforcement cases that relied on Section 451 to support a fine or penalty over the due process objections of the utility – and the only one that involved safety.[172] *Carey* undermines CPSD's position rather than supporting it. What was important to the Commission in *Carey* was that any reasonableness obligation imposed by Section 451 was objectively ascertainable by reference to an existing definition,

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[169] Ex. CPSD-5 at 2 (CPSD/Stepanian) (citation omitted).

[170] Ex. CPSD-5 at 1 (CPSD/Stepanian).

[redacted]

[172] The only other of which we are aware is Decision 04-09-062, 2004 Cal. PUC LEXIS 453, which resulted in the *Cingular* court of appeal decision, addressed below.

standard or common industry understanding. *Id.* (*citing Chodur v. Edmonds*, 174 Cal. App. [3d] 565 ([1985]) (term "dishonest dealing" was not unconstitutionally vague because it could be determined with reference to a common understanding)). In *Carey*, the utility had delegated to third party fumigators the utility's job of safely turning off gas service before a building was tented and fumigated. Without reference to an ascertainable standard or understanding, a general obligation to do such things as to "act in a safe manner" or "provide safe service" or "follow safe operating practices" would be too vague to enforce.[173] Analogous federal decisions in the OSHA employee safety context agree. If they are to be enforced at all, vague and open-ended safety regulations must be enforced with reference to objective and ascertainable understandings. *See F.A. Gray, Inc. v. Occupational Safety & Health Review Commission,* 785 F.2d 23, 24 (1st Cir. 1985) (Breyer, J.) (open-ended requirement requiring "appropriate personal protective equipment in operations where there is exposure to hazardous conditions" can be applied only to conduct "unacceptable in light of the common understanding and experience of those working in the industry"); *see also S & H Riggers & Erectors, Inc. v. Occupational, Safety & Health Review Commission*, 659 F.2d 1273, 1285 (5th Cir. 1981) ("The generality of [the regulation], however, mandates that it be applied only in such a manner that an employer may readily determine its requirements by some objective external referent.").

Here, CPSD reads Section 451 differently than did the Commission in *Carey*. CPSD did not address the "reasonable service, instrumentalities, equipment and facilities" clause in Section 451 upon which *Carey* relied, nor did it apply Section 451 with reference to a definition, standard or common understanding among the utilities. CPSD instead contends that "[a]ny unsafe condition or a violation of a utility safety practice may be a violation of Section 451."[174] As a result, CPSD largely ignores the part of *Carey* that defines Section 451's reasonable service clause with reference to an existing definition, standard or common industry understanding. CPSD also ignores the part of *Carey* that defines reasonableness according to a "common understanding among utilities." In the present case, PG&E submitted evidence establishing objective industry understandings and experience.[175] CPSD and the parties dismissed PG&E's

[173] Ex. CPSD-5 at 1-3 (CPSD/Stepanian).

[174] Ex. CPSD-5 at 1 (CPSD/Stepanian); *see id.* at 4 (CPSD/Stepanian) ("In fact, Section 451 placed (and continues to place) an affirmative duty on the utility to actin a safe manner.").

[175] *See, e.g.*, PG&E-1 at 3-5 to 3-7 (PG&E/Caligiuri); PG&E-1 at 5-1 to 5-17 (PG&E/Zurcher); PG&E-1 at 6-1 to 6-7 (PG&E/Kiefner); PG&E-1 at 11-1 to 11-23 (PG&E/Bull); Joint R.T. 647, 666-67, 679-84, 750-51, 783, 797-99 (PG&E/Zurcher); R.T. 338 (PG&E/Almario); R.T. 426, 442-43 (PG&E/Dickson); R.T. 848-50 (PG&E/Miesner);

reference to industry practices as irrelevant.[176] It is a strange position for CPSD to have taken given its use of a "good utility safety *practices*" standard. In its reliance on Section 451, CPSD has not brought itself within the reasoning of the Commission's decision in *Carey*.

CPSD also relies on a court of appeal decision, *Pacific Bell Wireless, LLC (Cingular) v. Public Utilities Comm'n*, 140 Cal. App. 4th 718 (2006), that sustained the Commission's reliance on Section 451 over due process objections. But *Cingular* does not support CPSD's position either. *Cingular* had nothing to do with safety. It involved a fine imposed by the Commission against a wireless telephone service provider for unjust and unreasonable practices relating to an early termination fee and the failure to disclose network problems that misled consumers about the available coverage and service. In rejecting a due process challenge to Section 451's application, the court pointed to three considerations. First, "Cingular could reasonably discern from the Commission's interpretations of Section 451 that its conduct in this instance would also violate the statute." *Id.* at 741. Second, information Cingular was receiving from its customers informed Cingular that "the totality of its acts and omissions were not just and reasonable." *Id.* at 742. Third, the court saw no appreciable difference between the specificity of Section 451 and civil fraud statutes. *Id.* at 742-43.

Cingular distinguishes itself. The prior Commission decisions that imparted notice in *Cingular* did so in ways that specifically alerted Cingular that its conduct "in this instance" was unlawful. PG&E had no such notice. The Commission has never applied Section 451 to punish a utility for what CPSD claims to have been general across-the-board shoddy gas operations.[177] The marketplace (Cingular's customers) also alerted Cingular that its practices were unreasonable.

Here, in contrast, CPSD has over many years audited PG&E's facilities and records without raising the alleged violations now asserted in this enforcement action.[178] In fact, PG&E had understood that in the past CPSD approved of many aspects of PG&E's risk management

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Joint R.T. 973-74, 1001-02, 1047 (PG&E/Keas); R.T. 1058-59 (PG&E/Caligiuri); R.T. 771-72, 779, 833-35 (PG&E/Kiefner).

[176] *See, e.g.*, R.T. 333, 338 (PG&E/Almario); Joint 685-88, 713, 715, 751-52 (PG&E/Zurcher); R.T. 743-44 (PG&E/Kiefner).

[177] Several Commission decisions have cited Section 451 in approving settlements in safety enforcement proceedings. *See, e.g., Investigation re PG&E Mission Substation Fire and Electric Outage Pursuant to Public Utilities Code Section 451*, D.06-02-003, 2006 Cal. PUC LEXIS 68 (2006). Under Rule 12.5 of the Commission's Rules of Practice and Procedure, such settlements have no precedential value.

[178] *See, e.g.*, PG&E-7 (Tabs 4-13, 4-14, 4-25); PG&E-1 at 10, Appendix A & Appendix B (PG&E/Almario).

and integrity management programs. [179] Finally, in the circumstances of this case, there is an appreciable difference between the specificity of Section 451 and the specificity of California's civil fraud statutes. The civil fraud statutes are at least static; their requirements do not change week-to-week. In contrast, CPSD stated in the San Bruno OII one set of expectations about what Section 451 required ("good utility safety practices"), [180] [redacted] Not only does CPSD's application of Section 451 lack the requisite specificity, within this proceeding alone CPSD has not applied a single, consistent standard by which it purports to judge safety violations under Section 451.

2. Any Attempt To Use Section 451 As A Free-Floating Pipeline Safety Law Violates Due Process/Fair Notice Principles

CPSD's inconsistent testimony demonstrates why Section 451 cannot fairly be used as a free-standing source of pipeline safety rules. In its rebuttal testimony in the San Bruno OII, CPSD asserted that Section 451 obligated PG&E to comply with "good utility safety practices."[183] [redacted] CPSD's position is that Section 451 has incorporated a blanket safety standard – whether it is "good utility safety practices," [redacted] is not clear – throughout the entire time span of the alleged violations (as far back as 1956 in the San Bruno OII, and 1930 in the Records OII). CPSD

[179] *See, e.g.*, PG&E-7 (Tabs 4-13, 4-14, 4-25); PG&E-1c at 4-1, 4-6, 4-11 to 4-12 (PG&E/Keas).

[180] Ex. CPSD-5 at 1 (CPSD/Stepanian).

[redacted]

[183] Ex. CPSD-5 at 1-3 (CPSD/Stepanian).

[redacted]

maintains this position despite the fact that it could not identify instances when the Commission had ever put utilities on notice of such a requirement.[186]

The Due Process Clause of the California Constitution precludes the Commission from adopting CPSD's position. Cal. Const., art. I, § 7. Analogous cases construing the federal Due Process Clause have held that due process is implicated where, as here, a party first receives actual notice of a proscribed activity through a citation initiating the enforcement action. *See Martin v. Occupational Safety & Health Rev. Comm'n*, 499 U.S. 144, 158 (1991) (noting that "the decision to use a citation as the initial means for announcing a particular interpretation may bear on the adequacy of noticed to regulated parties"). This is because due process requires that laws that regulate persons or entities must give fair notice of conduct that is forbidden or required. *F.C.C. v. Fox Television Stations, Inc.*, 132 S. Ct. 2307, 2317 (2012).

What the U.S. Supreme Court said last year in *F.C.C. v. Fox Television Stations* when it struck down an FCC indecency finding and penalty on due process grounds is equally applicable to CPSD's attempt to punish PG&E for alleged Section 451 violations:

> A fundamental principle in our legal system is that laws which regulate persons or entities must give fair notice of conduct that is forbidden or required. This requirement of clarity in regulation is essential to the protections provided by the Due Process Clause of the Fifth Amendment. It requires the invalidation of laws that are impermissibly vague. A conviction or punishment fails to comply with due process if the statute or regulation under which it is obtained "fails to provide a person of ordinary intelligence fair notice of what is prohibited, or is so standardless that it authorizes or encourages seriously discriminatory enforcement." [citation omitted] As this Court has explained, a regulation is not vague because it may at times be difficult to prove an incriminating fact but rather because it is unclear as to what fact must be proved.
>
> . . . [T]he void for vagueness doctrine addresses at least two connected but discrete due process concerns: first, that regulated parties should know what is required of them so they may act

[186] CPSD-5 at 3 (CPSD/Stepanian) (referring to *Cingular* as providing prior notice of the Commission's authority to impose safety violations under Section 451. As discussed above, *Cingular* is inapposite and does not provide the notice CPSD claims.); [redacted]

> accordingly; second, precision and guidance are necessary so that those enforcing the law do not act in an arbitrary or discriminatory way.[187]

CPSD's efforts to define Section 451's meaning violate the principles set out in *F.C.C. v. Fox Television Stations*. As demonstrated above, CPSD has not maintained a consistent position within these related proceedings, asserting a "good utility safety practices" standard that is apparently different from [redacted] Even putting aside CPSD's inconsistency, none of these standards were articulated prior to the initiation of the OIIs.[189]

In attempting to answer criticisms that CPSD has simply made up the Section 451 standards, CPSD points to the Commission's 1960 decision adopting GO 112, where the Commission stated that GO 112 did not "remove or minimize the primary obligation and responsibility" of the utilities to provide safe service and facilities.[190] While the quoted statement is unexceptional, as broad statements of regulatory policy often are, it is too vague and isolated to provide adequate notice of what conduct was prescribed or required. The Supreme Court in *F.C.C. v. Fox Television Stations* made this point in response to an argument similar to the one CPSD makes:

> The Government argues instead that ABC had notice that the scene in NYPD Blue would be considered indecent in light of a 1960 decision where the Commission declared that the "televising of nudes might well raise a serious question of programming contrary to 18 U.S.C. § 1464." [citation omitted]. The argument does not prevail. An isolated and ambiguous statement from a 1960 Commission decision does not suffice for the fair notice required

[187] *Fox Television Stations, Inc.*, 132 S. Ct. at 2317 (citations omitted).

[redacted]

[189] *See* Ex. CPSD-5 at 1-3 (CPSD/Stepanian) (filed August 20, 2012); [redacted]

[190] Ex. CPSD-5 at 2 (CPSD/Stepanian) (quoting CPUC Decision No. 61269 (1960) at 12).

> when the Government intends to impose over a $1 million fine fo r allegedly impermissible speech.

132 S. Ct. at 2319. [redacted]

> [redacted]

Section 451 does not by its terms give notice of any safety standard. CPSD has not identified any specific or enforceable pipeline safety standard, rule or practice submerged within Section 451, and certainly not one articulated anywhere prior to these proceedings. If its contradictory statements in this and the [redacted] are any guide, any attempt by CPSD to do so here would deprive PG&E of fair notice. [192] Fair notice concerns are especially weighty given the Commission 's indication that it may impose significant penalties and other remedial relief.

[redacted]

[192] *Compare* Ex. CPSD-5 at 1-3 (CPSD/Stepanian) (in which CPSD asserted PG&E violated a "good utili ty safety practices" standard) *with* [redacted]

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3. Section 451 Did Not Incorporate The ASME B31.8 Standard Prior To 1961

CPSD also maintains that in the era prior to the effective date of GO 112 (July 1, 1961), ASA B31.8 represented the accepted industry standards available at that time. From that premise, CPSD reasons that Section 451 incorporated ASA B31.8 prior to 1961.[193]

The Commission that adopted GO 112 would not have understood CPSD's logic. When adopting GO 112 in 1960, the Commission twice referred to the existing ASA B31.8 standard as a "voluntary" industry standard – a statement that makes no sense if CPSD is right in claiming that Section 451 already mandated adherence to it. [194] What the Commission understood it was doing when it issued GO 112 was adopting gas pipeline safety regulations for the first time in California. It did so over the gas utilities' arguments that their general adherence to the voluntary ASA B31.8 industry should forestall the need for regulation. [195] Thus, when the Commission adopted the ASA B31.8 -1958 standard, it modified it to make certain its provisions were "mandatory rather than left optional." [196] It would have been unnecessary for the Commission to make any provision of ASA B31.8 "mandatory rather than left optional," if in fact compliance with ASA B31.8 was already mandated by Section 451. [197] To accept CPSD's contrary interpretation is to conclude that the Commission that adopted GO 112 engaged in a needless exercise in Section 768 rulemaking.

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[193] Ex. CPSD-5 at 1 (CPSD/Stepanian) ("Section 451 is not prescriptive in the specific manner in which its obligations must be met. Without such specifics and because no set of regulations can cover every single possible unsafe condition, one looks to the industry standards and guidelines for guidance."); *id.* at 3 (CPSD/Stepanian) ("PG&E is incorrect in claiming that industry safety rules in existence in 1956 were merely 'guidelines' that created no duty for PG&E to follow them. In fact, Section 451 placed (and continues to place) an affirmative duty on the utility to act in a safe manner.").

[194] *Investigation into the Need of a General Order, etc.*, Decision No. 61269 (1960) at 4, 6. But CPSD has not always been consistent. In the course of Mr. Harrison's cross-examination in the joint proceeding, Mr. Foss indicated that he understood that the pre-1961 ASA B31.8 was not mandatory. Joint R.T. 412 (PG&E/Harrison). [redacted]

[195] *Investigation into the Need of a General Order, etc*, Decision No. 61269 (1960) at 6.

[196] *Investigation into the Need of a General Order, etc*, Decision No. 61269 (1960) at 11.

[197] CPSD also maintains that PG&E was mandated to follow ASA B31.8 because in the proceedings leading to the adoption of GO 112, PG&E and the other major gas utilities represented to the Commission that they generally followed it. That contention suffers from the same logical fallacy. The Commission that adopted GO 112 understood that the gas utilities had represented that they generally followed the ASA B31.8 standard. The Commission conveyed that understanding in the context of explaining why those assurances were not sufficient. In other words, the Commission did not rely on those assurances; it adopted GO 112 notwithstanding the assurances.

IV. OTHER ISSUES OF GENERAL APPLICABILITY

The San Bruno accident changed the way regulators, operators and the industry view gas pipeline safety, changes that will ultimately result in safer gas pipelines and operations. PG&E supports such progress and is actively improving the safety of its pipeline system and operations. In this proceeding, however, CPSD and the intervening parties have attempted to use PG&E's improvement initiatives against it, asserting that PG&E's actions to improve demonstrate prior deficiencies and legal violations. Taking steps to improve its operations and pipeline safety in response to post-San Bruno expectations and standards has no legitimate relation to establishing alleged violations.[198] Similarly, CPSD asserts violations against PG&E that are based on information that only came to light after the San Bruno accident or are based on safety perspectives that evolved out of the lessons learned from the accident. Alleging violations based on hindsight and changed expectations is not appropriate, and the Commission should not find violations on that basis.

Below, PG&E discusses three examples of hindsight improperly serving as the foundation for alleged violations. PG&E also discusses its improvement initiatives and why connecting those actions to alleged legal violations is unwarranted and unsupported.

A. CPSD Alleges Violations Based On Hindsight

1. "Unknown" Pipe Specifications For Pups

CPSD alleges PG&E violated the yield strength standards in ASA B31.1.8-1955 and API 5L because the six pups involved in the San Bruno accident did not have yield strength of 52,000 psig (pounds per square inch gauge), the specification to which the rest of Segment 180 was built.[199] At the hearing, CPSD's counsel cross-examined PG&E witnesses regarding the assumed SMYS value that PG&E purportedly should have used for Segment 180 if it did not know the yield strength of the pipe. The implication of CPSD's questioning is that, because the pups were manufactured to an "unknown" specification, the regulations required PG&E to assume a SMYS value of 24,000 psig.[200] The conclusion CPSD apparently advocates is that the

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[198] Evid. Code § 1151.

[199] Ex. CPSD-1 at 19-20 (CPSD/Stepanian); Ex. CPSD-5 at 6-7 (CPSD/Stepanian).

[200] Joint R.T. 19-21 (PG&E/Zurcher); *see* Joint R.T. 392-94 (PG&E/Harrison); Joint R.T. 980-82, 995-96 (PG&E/Keas).

assumed SMYS value of 24,000 psig would have resulted in a lower MAOP and operating pressure on Segment 180, which would in turn have prevented the rupture on September 9, 2010.[201]

CPSD's suggestion is not supported by any evidence that pre-dates the San Bruno accident. 49 C.F.R. § 192.107 ("Yield strength (S) for steel pipe") provides that an operator must use a yield strength of 24,000 psig for pipe "whose specification or tensile properties are unknown" and that has not been tensile tested. The section only applies, however, when the operator is aware that it has pipe with unknown specifications.

Only hindsight knowledge developed by the NTSB metallurgical testing after the accident allows CPSD to assert the yield strength of the six pups was "unknown." Prior to September 9, 2010, PG&E's records contained pipe attribute information for all of Segment 180, including the pipe yield strength.[202] To PG&E's knowledge, it was not missing the SMYS value for any of the pipe in Segment 180. Following the rupture, it became clear that the pipe attribute information for Segment 180 was incorrect with regard to SMYS value (42,000 psig instead of 52,000 psig) and seam type (seamless instead of DSAW). It is undisputed that PG&E did not know the six pups were in Segment 180, and that PG&E only became aware of the pups' existence after Segment 180 ruptured.[203] Before September 9, 2010, PG&E had no reason to think it needed to use an assumed SMYS value for any portion of Segment 180.[204] Incorrect information is not "unknown" information that would alert an operator to the need for an assumed value. In fact, the hindsight knowledge of the actual SMYS values of the six pups shows that the lower SMYS played no role in the rupture. The cause of the rupture was the combination of a missing interior weld, a ductile tear, and 50 years of fatigue crack growth.[205]

Moreover, it is not disputed that, if PG&E had known that Segment 180 contained the defective pups, it would have immediately removed them. Harrison stated it succinctly:

> Q: Now, if at some point in time PG&E's management had discovered the existence of the missing welds in the pup sections what, to your knowledge, would PG&E have done?

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[201] Joint R.T. 422 (PG&E/Harrison); Joint R.T. 996-98 (PG&E/Keas).

[202] Ex. CPSD-1 at 64-65 (CPSD/Stepanian).

[203] Joint R.T. 74-75 (PG&E/Zurcher); Joint R.T. 336 (PG&E/Harrison); Joint R.T. 368, 391, 562 (PG&E/Harrison); Joint R.T. 1010-12, 1055 (PG&E/Keas).

[204] Joint R.T. 60-61, 69-71 (PG&E/Zurcher); Joint R.T. 368, 386, 390–93 (PG&E/Harrison).

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

> A: I think they would have immediately taken the line out of service and replaced the pipe.[206]

Knowledge of the pups and their condition would not have led PG&E to use a "more conservative" assumed SMYS value, the purported failing CPSD alleges. Nor would it have changed the integrity management assessment methodology used on Segment 180. Rather, had PG&E known of the pups, it would have immediately cut them out and replaced them with the appropriate pipe.[207]

2. DSAW Pipe Subject To A Seam Threat??

PG&E's specifications for the Segment 180 construction called for 30 -inch, 0.375-inch wall thickness, 52,000 psig SMYS, DSAW pipe.[208] DSAW pipe refers to double submerged arc welded pipe, where the longitudinal seam is welded first on the outside of the pipe and then on the inside.[209] As Dr. Caligiuri testified:

> At the time, given the pipe manufacturing techniques available for 30-inch diameter pipe, DSAW pipe was the highest-quality pipe of that size PG&E could have used for Segment 180. There is no stronger practical way to join together the edges of a large piece of metal rolled into gas transmission pipe.[210]

CPSD, however, asserts that, before the San Bruno accident, PG&E should have deemed DSAW pipe to be subject to a long seam manufacturing threat and conducted integrity management assessments on that basis.[211]

CPSD's contention revises history. CPSD has not produced evidence to dispute that, before September 9, 2010, the natural gas pipeline industry, pipeline industry experts and pipeline regulators, as well as the pipeline safety standards and regulations, all considered

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[206] Joint R.T. 337-38 (PG&E/Harrison); Joint R.T. 1019, 1066 (PG&E/Keas); Joint R.T. 692 (PG&E/Kiefner).

[207] Joint R.T. 1051 (PG&E/Keas) ("Standing alone, if we knew that they were there, we would have cut them out. We wouldn't wait for an integrity management program to do an evaluation for them.")

[208] Ex. PG&E-1 at 2-2 (PG&E/Harrison).

[209] R.T. 1062 (PG&E/Caligiuri) (describing his conclusion that the pups on Segment 180 were intended to be DSAW pipe, and not single submerged arc welded pipe that did not penetrate fully, Dr. Caligiuri testified as follows: "Based on the cross sections I looked at, it's my interpretation that this pup was intended to be a double submerged arc weld, which means welds on both the outside and the inside. In the cross sections prepared by the NTSB and then I examined from these three pups, that it was apparent that the inner submerged arc weld was not completed.").

[210] Ex. PG&E-1 at 3-5 (PG&E/Caligiuri).

[211] Ex. CPSD-1 at 42-49 (CPSD/Stepanian).

DSAW pipe to be reliable and safe pipe not subject to a long seam threat.[212] The federal pipeline safety regulations identified DSAW pipe as having a joint efficiency factor of 1.0. [213] Under the AMSE B31.8S code, by definition this eliminated the need to consider potential longitudinal seam manufacturing threats on that pipe. [214] ASME B31.8S-2004, § 6.3.2 ("Seam issues have been known to exist for pipe with a joint factor of less than 1.0").

Even after the San Bruno accident, DSAW pipe continues to be viewed as dependable, safe pipe. As Dr. Caligiuri testified, DSAW pipe "is considered among metallurgists in the gas transmission pipe field today to be one of the highest- quality welded pipe."[215] Properly made DSAW pipe is not considered subject to long seam threats, and would not be expected to experience cyclic fatigue in a natural gas transmission pipeline for decades, if not hundreds of years.[216]

Contrary to PG&E' s specifications, however, one section of pipe installed in Segment 180 contained six short pups, three of which were missing the internal weld along the longitudinal seam. PG&E did not know the pups were there, let alone that three of them were missing internal welds.[217] The missing interior welds were not mere manufacturing defects; they represented a complete breakdown in the manufacturing process. Had PG&E known, PG&E would have immediately replaced the pipe.[218]

CPSD's contention that PG&E should have co ncluded the DSAW pipe in Segment 180 was subject to a long seam manufacturing threat, and that it constitutes a violation of law that PG&E did not, represents a hindsight judgment that has no support in the facts or law. It is based on the hindsight knowledge of the San Bruno accident.

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[212] Ex. PG&E-1 at 3-5 (PG&E/Caligiuri); Joint R.T. 973-74 (PG&E/Keas); Joint R.T. 733, 790 (PG&E/Kiefner). As Dr. Caligiuri testified, "Absent any corrosion damage, well-manufactured DSAW pipe from the late 1940s or early 1950s would not have needed replacement merely due to its age in 2010 under any industry practice or standard." Ex. PG&E-1 at 3-5 (PG&E/Caligiuri).

[213] 49 C.F.R. § 192.113.

[214] *See, e.g.,* Joint R.T. 968-69, 992-93 (PG&E/Keas) ("The point that I am trying to make with this testimony is that DSAW . . . [has] a really good performance in the industry. And that's the reason why they're established as having a joint efficiency factor of one" thus DSAW seams "would not be considered a manufacturing threat").

[215] Ex. PG&E-1 at 3-5 (PG&E/Caligiuri).

[216] R.T. 691-92, 714-15, 731, 741-42 (PG&E/Kiefner); Joint R.T. 1198-99 (PG&E/Keas) (quoting Ex. PG&E-3 at 1, "Typically gas pipelines are not a significant risk of failure from pressure cycle induced growth of original manufacturing defects."); R.T. 803 (PG&E/Kiefner) (indicating the defective pup had a fatigue risk, but there wasn't "a fatigue risk in general" with DSAW pipe).

[217] Ex. PG&E-1 at 2-3 to 2-4 (PG&E/Harrison).

[218] Joint R.T. 336-38 (PG&E/Harrison).

3. Automated Valves

At the evidentiary hearing, CPSD and the City of San Bruno took PG&E to task for not having automated valves on Line 132 in close proximity to the rupture site on the assumption that the gas could have been shut off sooner. [219] CPSD criticized PG&E for the time it took to isolate the rupture on September 9, 2010, stating:

> PG&E took 95 minutes to stop the flow of gas and isolate the gas. According to the NTSB Report, the response time was "excessively long and contributed to the extent and severity of property damage and increased the life-threatening risks to residents and emergency responders." [220]

Faulting PG&E for not having automated valves every few miles on Line 132, or throughout its transmission system, is another case of judgment by hindsight and changed expectations. Asserting a violation of law based on that judgment is without merit. [221] Prior to September 9, 2010, the use of closely-spaced automated valves on gas transmission pipelines was not the industry norm.[222] Nor did the federal pipeline regulations or GO 112-E mandate that automated valves be installed in any minimum numbers or at any particular distance along transmission pipelines. [223] Automated valves do not prevent ruptures, and operators cannot predict where ruptures might occur and thus where automated valves may be needed.

As CPSD itself recognizes, the benefits automated valves provide in a tragic accident like San Bruno are open to discussion:

> The vast majority of injuries, fatalities, and property damage associated with a catastrophic pipeline incident occur within the first few minutes of the event, well before activation of ASVs or RCVs are possible. (Footnote omitted.) Automatic shut off-valves and remote control valves will not prevent a pipeline rupture from happening and may not lessen any related injuries or property damage. In the [Department of Transportation's] [sic– 1999] 1996

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[219] R.T. 337-40 (PG&E/Almario).

[220] Ex. CPSD-5 at 54-55 (CPSD/Stepanian) (citing NTSB Report, Executive Summary).

[221] R.T. 203 (PG&E/Almario) ("So I think we've been doing the prudent thing by installing them as we retrofitted facilities and as we saw need for them. Just didn't –we did not have them at that location on September 9.").

[222] Ex. PG&E-1 at 5-17 (PG&E/Zurcher); R.T. 340 (PG &E/Almario) ("So that's why there's a lot of technical discussion about – and even within PG&E we're looking to continue the discussion but be much more aggressive in the installation of those valves. But there is some controversy around installation of the valves and the overall effectiveness of the valves with restricting overall, you know, damage to an event.").

[223] *See* 49 C.F.R. § 192.935(c) (requiring operators to evaluate the use of automated valves, with no mandate regarding installation of a certain number or maximum separation).

> report, the DOT acknowledged that there had been insufficient studies on the reduction of property damage with the use or RCVs and ASVs. They also acknowledge that there was insufficient data to establish an appropriate standard time to isolate a ruptured pipeline section.[224]

The San Bruno accident changed how industry, regulators, lawmakers [225] and the public view pipeline safety and what actions should be taken to best ensure it. Installation of more automated valves on gas transmission pipelines in highly-populated areas is one such area of change.[226] Since the San Bruno accident, PG&E has committed to install more automated valves throughout its gas transmission system.[227] Acting on that commitment, PG&E expects to install approximately 200 automated valves by the end of 2014. [228] To fault PG&E, however, for the absence of automated valves in close proximity to the rupture location prior to the San Bruno accident is to judge PG&E's pre -San Bruno conduct through a post-San Bruno lens. To assert violations of law based on such hindsight is not appropriate or supported by the facts.

B. PG&E's Post-Accident Improvement Efforts

Throughout the proceeding, CPSD and intervening parties have suggested two negative inferences from the efforts PG&E made post-San Bruno to improve its gas operations and public safety. First, in the hearings, parties implied that PG&E's improve ments are proof that PG&E violated the law.[229] Second, in its reply testimony, CPSD argues that PG&E's improvements are mostly mandated by the Commission or by statute,[230] suggesting that PG&E's improvements "do not offer to provide a greater level of safety or exceed the standards." [231] Both suggestions are wrong.

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[224] Ex. CPSD-1 at 105 (CPSD/Stepanian).

[225] *See, e.g.,* Pub. Utilities Code § 957 (mandating automated valves in certain situations).

[226] Joint R.T. 820-24 (PG&E/Zurcher).

[227] Ex. PG&E-1 at 8-17 to 8-19 (PG&E/Kazimirsky/Slibsager); R.T. 341-42 (PG&E/Almario); Joint R.T. 195 (PG&E/Kazimirsky/Slibsager). PG&E explained in detail in its August 26, 2011 PSEP submission its commitment to automated valves.

[228] Ex. PG&E-1 at 8-17 to 8-18 (PG&E/Kazimirsky/Slibsager).

[229] *See, e.g.*, R.T. 1009 (PG&E/Yura); R.T. 401 (PG&E/Almario).

[230] Ex. CPSD-5 at 63 (CPSD/Stepanian).

[231] Ex. CPSD-5 at 63 (CPSD/Stepanian).

The parties incorrectly infer that PG&E's improvement initiatives signified that there were prior violations of law. The City of San Bruno put the claim succinctly when it asked Ms. Yura the following question:

> Ms. Strottman: Q: So I guess I don't understand your testimony. You described significant changes that PG&E has made correct since the September 9 explosion? [....] Yet you refused to acknowledge that there were several deficiencies at PG&E on September 9, 2010 leading to the explosion; is that right?[232]

The issue before the Commission is not whether PG&E could have done things better, but whether it violated laws or regulations. Expert after expert has testified in this proceeding that the violations CPSD has alleged are not supported by the facts or the applicable regulations and standards.[233] PG&E's numerous actions to enhance the safety of its gas operations following the San Bruno accident are a combination of, among other things, remedial actions to improve identified shortcomings, new initiatives to respond to changed expectations and safety standards, good-faith response to directives by the Commission, recommendations by the NTSB and the IRP, and internally-identified programs focused on top to bottom improvement in PG&E's gas operations. That PG&E is undertaking all these actions is not evidence of prior violations of law.

In addition to being unsupported by the facts, the parties' reliance on PG&E's post-accident improvement efforts to support alleged legal violations is legally inappropriate. California statutory and case law are clear that evidence of subsequent improvements cannot be used to prove that a party was negligent or otherwise culpable. Evid. Code § 1151 (subsequent remedial or precautionary measures are not admissible evidence of negligent or culpable conduct); *Alcaraz v. Vece*, 14 Cal. 4th 1149, 1168-69 (Cal. 1997) (subsequent remedial measures are not admissible evidence of culpable conduct under Evidence Code § 1151); *Gilliam v. American Casualty Co.*, 735 F. Supp. 345, 351, n.9 (N.D. Cal. 1990) (under Federal Rule of

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[232] R.T. 1009. *See* R.T. 401 ("Ms. Strottman: Mr. Almario . . ., you kind of made a distinction between deficiency versus room for improvement. Can you explain what distinction you're making?"); R.T. 463 ("Ms. Strottman: So if PG&E's response was adequate, why are you making all these changes?"); R.T. 999 ("Ms. Strottman: Now, was this new quality and improvement department instituted within PG&E because of some deficiencies within PG&E's quality controls in its gas operations?"); R.T. 1013-14 ("Mr. Yang: And doesn't the fact that there's consistency in the findings that the emergency response, the integrity management and the recordkeeping needed to be improved indicate that there was a problem at PG&E in those areas?"); R.T. 1022.

[233] *See, e.g.*, Ex. PG&E-1 at 5-1 to 5-17 (PG&E/Zurcher); Joint R.T. 2-81, 642-889 (PG&E/Zurcher); Ex. PG&E-1 at 9-1 to 9-14 (PG&E/Miesner); R.T. 843-65 (PG&E/Miesner); Ex. PG&E-1 at 11-1 to 11-29 (PG&E/Bull); R.T. 411-31 (PG&E/Bull); Exs. PG&E-10 & PG&E-11 (PG&E/O'Loughlin); R.T. 535682 (PG&E/O'Loughlin).

Evidence 407, evidence of subsequent remedial measures is not admissible to prove culpable conduct by the party taking those measures).

CPSD also wrongly asserts that PG&E's improvement actions do not provide a greater level of safety or exceed applicable standards. [234] PG&E's improvements will meet and in some instances exceed new regulatory and industry standards. To name but a few, PG&E's automated valve program will enable PG&E to have automated control capability and real-time knowledge of pipeline conditions at least every 5 to 8 miles on large diameter pipelines in Class 3 and 4 areas.[235] PG&E's MAOP validation effort goes beyond HCA locations (the Commission's directive), and includes all transmission pipelines in PG&E's system. [236] PG&E is also increasing the frequency of HCA pipeline segment patrols from quarterly to bimonthly, and doing accelerated leak repairs.[237] With regard to leak detection, PG&E became the first utility in the world to use Picarro's car-mounted natural gas leak detection device, which is more sensitive than traditional instruments. [238] PG&E is also seeking to become one of the first United States companies, if not the first, to become certified under the Publicly Available Specification (PAS) 55.[239]

None of these actions should be used to assert violations of law against PG&E, and each will enhance PG&E's gas operations and safety. Whether the result of a directive, recommendation, or undertaken at PG&E's initiative, these actions should be supported by the parties, not forged into a weapon against PG&E.

[234] Ex. CPSD-5 at 63 (CPSD/Stepanian).
[235] Ex. PG&E-1 at 8-1 (PG&E/Kazimirsky/Slibsager).
[236] R.T. 1003 (PG&E/Yura).
[237] R.T. 1004 (PG&E/Yura).
[238] Ex. PG&E-1 at 13-9 (PG&E/Yura).
[239] R.T. 1015-17 (PG&E/Yura).

V. CPSD ALLEGATIONS

A. Construction Of Segment 180

1. CPSD Failed To Prove Alleged Violations Of ASA B31.1.8's Voluntary Standards In The Construction Of Segment 180

PG&E has long acknowledged that, in 1956 it unknowingly installed a defective piece of pipe in Segment 180, and that pipe should not have been put into service.[240] CPSD, however, goes beyond this 50-year old act of negligence and pursues a series of alleged violations related to the Segment 180 construction that are based solely on voluntary industry guidelines, CPSD's use of Section 451 as a catch-all safety provision, and the hindsight knowledge from the 2011 NTSB metallurgical examination. These alleged violations lack both factual and legal support.

a. Yield Strength

CPSD alleges, "Although PG&E records showed that Segment 180 was manufactured in accordance with API 5LX Grade X52 specifications, none of the pups in the ruptured section of Segment 180 met the minimum yield strength requirements of API 5LX Grade X52 and only pups 4 and 6 met the minimum yield strength values required by API 5LX Grade X42 specified in ASA B31.1.8- 1955."[241] PG&E acknowledges the NTSB's finding that the pups installed in Segment 180 did not meet the specified SMYS.[242] But that does not establish a violation.

CPSD's reliance on the voluntary guideline ASA B31.1.8 -1955, Section 805.54, is misplaced. Section 805.54 is part of a section of ASA B31.1.8-1955 entitled, "Units and Definitions." The section does no more than define specified minimum yield strength; it does not contain a construction standard or guideline (whether mandatory or voluntary) for use of pipe with any particular SMYS value.[243] Section 805.54 provides in full as follows:

> Specified minimum yield strength is the minimum yield strength prescribed by the specifications under which pipe is purchased from the manufacturer (psi). [Emphasis in original]

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[240] Ex. PG&E-1 at 1-1 (PG&E/Yura).

[241] Ex. CPSD-1 at 20 (CPSD/Stepanian) (citing ASA B31.1.8-1955, § 805.54).

[242] Ex. PG&E-1 at 2-1 n. 1, 2-5 (PG&E/Harrison). Specified minimum yield strength, or SMYS, is the strength below which the manufacturer, in accordance with American Petroleum Institute (API) specifications, guarantees that the pipe will not experience plastic (permanent) deformation. The SMYS for the 30-inch diameter DSAW pipe Consolidated Western made for PG&E was 52,000 psig.

[243] PG&E's Request for Official Notice, Ex. 5 (Ex. Records PG&E-47 (ASA B31.1.8), § 805.54 (1955)).

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Thus, putting aside the fact that the whole ASA is voluntary, Section 805.54 cannot support an alleged violation of law.

b. Wall Thickness

CPSD alleges, "PG&E failed to measure the wall thickness to determine compliance with the minimum wall thickness in accordance with Section 811.27 of ASA B31.1.8-1955."[244] Section 811.27 only applies to "[u]sed pipe, unidentified new pipe, and pipe purchased under Specification ASTM A120.[245] None of these describe the 30-inch, 0.375-inch wall thickness, 52,000 psig SMYS DSAW pipe specified for Segment 180. Section 811.27C, which addresses wall thickness, applies "unless the wall thickness is known with certainty." In 1956 – and until September 9, 2010 – PG&E believed it knew the wall thickness and other pipe specifications with certainty. Without the hindsight knowledge acquired after the accident, in 1956, no one would have looked to Section 811.27 in connection with the Segment 180 construction, and CPSD has not shown otherwise.

CPSD's allegations focus on the thickness of the long seam welds in the pups and misapprehend the meaning of wall thickness as used in the industry.[246] Wall thickness is a metric applied to the pipe body. Section 811.27 itself refers to determining the wall thickness by "measuring thickness at quarter points on one end of each piece of pipe." It does not mention measuring the thickness of the longitudinal seam weld. As Mr. Harrison explained, long seam welds are evaluated according to a separate metric, independent from pipe body wall thickness calculations:

> [T]he seam weld is in itself evaluated. So the design formulas and the code requirements are all using Barlow's equation to calculate the basic stress on the pipe, and the seam weld has a longitudinal or efficiency factor that is applied to it. So the seam weld itself is considered sort of a unit and is evaluated independent of the wall thickness calculations.[247]

[244] Ex. CPSD-1 at 21 (CPSD/Stepanian).

[245] PG&E's Request for Official Notice, Ex. 5 (Ex. Records PG&E-47 (ASA B31.1.8), § 811.27 (1955)).

[246] Ex. CPSD-1 at 21 (CPSD/Stepanian).

[247] Joint R.T. 399-400 (PG&E/Harrison).

The hindsight knowledge acquired through the NTSB metallurgical examination confirmed that the wall thickness of the pipe in Segment 180, including the pups, was consistent with the 0.375-inch specification.[248]

c. Weldability

CPSD originally alleged, "The girth welds of the pups did not meet the requirements of Section 811.27E Weldability of ASA B31.1.8-1955 which required the welds be done by a qualified welder and tested in accordance with requirements of API Standard 1104."[249]

PG&E's testimony demonstrated that Section 811.27E Weldability relates to the suitability of types of pipe for welding, not girth welds made during construction.[250] Recognizing this, CPSD withdrew this allegation in its rebuttal testimony.[251] At the same time, however, CPSD claimed that the girth welds between the pup sections in Segment 180 were defective.[252] CPSD's belated claim also fails. CPSD did not identify a standard by which "defective" girth welds wer e to be determined, did not offer any evidence that the girth welds between the pups fell below any such standard, and did not identify any legal requirement or regulation that could support an alleged violation of law related to these girth welds.[253]

d. Minimum Length

CPSD alleges, "[A]ll of the pups used for Segment 180 were less than 5 ft. PG&E did not meet the minimum length requirement of API 5LX standard when the pups were installed in 1956."[254] The fact that the pups were shorter than 5 feet in length is undisputed. CPSD's alleged violation fails nonetheless.

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[248] Ex. CPSD-9 (NTSB Report) at 41 ("All six pups were nominal 0.375-inch wall thickness pipe…."); Ex. PG&E-1 at 2-6 (PG&E/Harrison).

[249] Ex. CPSD-1 at 21 (CPSD/Stepanian).

[250] Ex. PG&E-1 at 2-6 (PG&E/Harrison).

[251] Ex. CPSD-5 at 7 (CPSD/Stepanian) ("CPSD withdraws this allegation.").

[252] Ex. CPSD-5 at 7 (CPSD/Stepanian).

[253] Ex. CPSD-5 at 7 (CPSD/Stepanian) (referring back to Ex. CPSD-1 at 21 (CPSD/Stepanian), and the NTSB Report (Ex. CPSD-9 at 43), neither of which demonstrated that the pup girth welds fell below any particular standard, much less any legal standard).

[254] Ex. CPSD-1 at 22 (CPSD/Stepanian).

API 5LX is a standard directed to manufacturers and not pipeline operators and pipe purchasers, like PG&E.[255] PG&E does not manufacture pipe and did not manufacture the pups found in Segment 180.[256] Under the API 5LX manufacturing standard, "no length used in making a jointer shall be less than 5 ft."[257] Though pipe purchasers, like PG&E, may refer to the standard when ordering pipe from a manufacturer, the API 5LX standard does not establish a legal standard applicable to the pipe purchaser.[258]

e. Post-Installation Pressure Test

CPSD alleges "PG&E was unable to produce records showing that pipe in Segment 180 had been strength tested and therefore failed to follow ASA B31.1.8-1955 strength testing requirements."[259] While records of a post-installation hydro test for Segment 180 have not been located, the evidence suggests that PG&E did hydro test the pipe after installation.[260] In any event, as CPSD acknowledges, no federal or state law required PG&E to do so.[261] CPSD bases this purported violation on PG&E's alleged failure to perform a task it was never required by law to do.

[255] Ex. PG&E-1 at 2-6 (PG&E/Harrison).

[256] Joint R.T. 375-76 (PG&E/Harrison); R.T. 1081 (PG&E/Caligiuri); *see* Ex. PG&E-1 at 3-4 (PG&E/Caligiuri) ("gas transmission pipeline operators (including PG&E) do not manufacture such pipe); Ex. PG&E-1 at 3-16 (PG&E/Caligiuri) ("Based on my experience, historical record review, and the specialized equipment that would have been required to bend the 3/8 inch plate into a cylinder, PG&E would not have been able to fabricate these pups.").

[257] API Std. 5LX, 5th Ed. Nov. 1954, at 10 (A "jointer" is "two pieces joined by welding to make a standard length."); Ex. PG&E-1 at 2-6 (PG&E/Harrison).

[258] Ex. PG&E-1 at 2-6 (PG&E/Harrison); Joint R.T. 410-11 (PG&E/Harrison). As discussed above, the source of all pipe used on the Segment 180 relocation job cannot be determined today. However, it is likely that it was obtained from existing PG&E stock, which was plentiful at the time with pipe purchased from Consolidated Western for use on Line 132, Line 153 and Line 131. The purchase orders PG&E placed with Consolidated Western for these projects specified a jointer length consistent with the API 5LX standard. If the pups had been delivered to the Segment 180 relocation job site welded together, double wrapped, and coated to prevent external corrosion, PG&E would not have readily known that the pups existed, or that the jointers failed to conform to PG&E's specifications for the job. Ex. PG&E-1 at 2-1 to 2-7 (PG&E/Harrison).

[259] Ex. CPSD-1 at 22 (CPSD/Stepanian).

[260] Ex. PG&E-1 at 3-11 (PG&E/Caligiuri).

[261] Ex. CPSD-1 at 18 (CPSD/Stepanian). ("At the time Segment 180 was constructed in 1956, the Commission had jurisdiction over the safety of PG&E natural gas transmission facilities but there were no specific federal or state safety regulations applicable to transmission line construction."); *see* Ex. PG&E-1 at 2-7 (PG&E/Harrison); Ex. PG&E-1 at 3-11 (PG&E/Caligiuri).

(i) In 1956, No Legal Requirement To Hydro Test Segment 180 Existed

The record evidence establishes that, in the early 1950s, hydro testing natural gas pipelines presented unique challenges and had not been widely adopted in the industry.[262] The technology was still relatively new when Segment 180 was installed in 1956. Hydro testing first appeared in industry guidelines in 1955 as a recommended practice in ASA B31.1.8.[263] The evidence is undisputed that ASA's recommendation was voluntary industry guidance and not a legal mandate.[264]

Post-installation pressure testing did not become an accepted practice industry-wide until after the installation of Segment 180.[265] It was another several years before state and federal regulators and lawmakers incorporated hydro testing into a legal requirement.[266] Even then, however, the new rules and regulations applied only prospectively and had no impact on existing pipelines, including Segment 180.[267] Segment 180 was never subject to a legal requirement to be hydro tested.

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[262] Ex. PG&E-1 at 3-11 (PG&E/Caligiuri); Joint R.T. 354-57 (PG&E/Harrison); Joint R.T. 355 (PG&E/Harrison) ("In the 50s they didn't have any great way to get high pressure wate r. So water testing – and also, water, you are putting a bunch of water in a gas pipeline. So then how do you get that water back out of the pipeline? You always – it is virtually impossible to get it all out. Even today we measure dew point. We do lots of things to make sure our pipelines are dry. So testing with water wasn't necessarily the favored way to go.").

[263] Ex. PG&E-1 at 3-11 (PG&E/Caligiuri) ("The preceding 1952 ASA Code gave hydrostatic testing little mention, noting that pipeline operators 'may' use hydrostatic testing. In a series of 1954 articles, the Chairman of the ASA Committee charged with drafting the 1955 B31.1.8 provisions noted that 'it was quite general practice in the gas industry' not to hydrostatically test pipelines."); PG&E's Request for Official Notice, Ex. 5 (Ex. Records PG&E-47 (ASA B31.1.8) at 18 (1955)).

[264] Ex. CPSD-1 at 18 (CPSD/Stepanian); Ex. PG&E-1 at 3-11 (PG&E/Caligiuri).

[265] Ex. PG&E-1 at 2-7 (PG&E/Harrison); Ex. PG&E-1 at 3-11 (PG&E/Caligiuri); Joint R.T. 352-57 (PG&E/Harrison).

[266] Ex. PG&E-1 at 2-8 (PG&E/Harrison). General Order 112 became effective in California in 1961. Federal regulations adopted under the Natural Gas Pipeline Safety Act of 1968 became effective in 1970.

[267] Ex. PG&E-1 at 2-8 (PG&E/Harrison). In particular, federal regulations at 49 C.F.R. § 192.619(c) "grandfathered-in" existing pipelines based on prior operating pressure history and did not require pressure testing of existing pipelines to establish the appropriate MAOP. In December 2003, the Department of Transportation reaffirmed the grandfather clause at section 192.619(c) as an appropriate practice when it rejected a proposal that would require "once in a lifetime" pressure testing of existing pipelines. *Id.* at n.5 (PG&E/Harrison) (relying on decades-long historical safe operation of many pipelines, the Department of Transportation concluded, "it is not necessary to require a once-in-a-lifetime pressure test to address the threat of material and construction defects.").

(ii) The Record Supports The Conclusion That Segment 180 Was Hydro Tested In 1956

Despite the lack of any legal requirement to do so, the record supports the conclusion that PG&E performed a post-installation hydro test on Segment 180.[268] First, a former PG&E employee testified (in the civil litigation related to the San Bruno accident) that he observed a hydro test on a newly-installed transmission pipeline in the same location as the Segment 180 relocation job, between San Bruno Avenue and Sneath Lane.[269] From the description of the timing and location of the job, it appears that he observed a pressure test on the Segment 180 relocation project.[270]

Second, as Mr. Harrison testified, the Segment 180 job file contains documents showing the purchase of material specific to a hydro test: two 30-inch end caps; 20 or 30 feet of 4-inch pipe; and about 125 feet of inch-and-a-half pipe.[271] These items would have been used to construct the water supply and removal facilities used in hydro testing:

> And [these purchases] would indicate that they would have put that pipe together to supply water to either fill up pipe with hydrostatic test water and test it to pressure and to remove the water also. They had to have a way to get the water out of the pipe. So the purchase of those items on the job sort of indicates that it may have been hydrostatically tested.[272]

Finally, Dr. Caligiuri's metallurgical analysis of the pup sections support the conclusion that PG&E conducted a post-installation hydro test in 1956 on Segment 180.[273] Dr. Caligiuri

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[268] *See generally* Ex. PG&E-1 at 3-5 to 3-17 (PG&E/Caligiuri).

[269] Ex. CPSD-156 at 38-61.

[270] Ex. PG&E-1 at 2-9 (PG&E/Harrison). PG&E recognizes that the former employee also testified to certain facts that he apparently remembered incorrectly, e.g., the pressure test being approximately 1,000 psi. When his recollection is coupled with the information in the job file and the metallurgical analysis of Dr. Caligiuri, however, that discrepancy does not justify disregarding his testimony.

[271] Joint R.T. 413-14 (PG&E/Harrison).

[272] Joint R.T. 413-14 (PG&E/Harrison); *id.* at 413 (PG&E/Harrison) ("And the only logical reason they would need 30-inch caps is as I described on the board earlier, they would have caps on the end of the pipe in order to test it. And there were also ordered some 4-inch pipe and some inch-and-a-half or inch-and-a-quarter steel pipe and relatively short distances…."); Ex. Joint-10 at HRG 0008, HRG 0019, HRG 0073, HRG 0095, HRG 0119, and HRG 0203.

[273] Ex. PG&E-1 at 3-5 to 3-17 (PG&E/Caligiuri); *id.* at 3-2 (PG&E/Caligiuri) ("My analysis and conclusions are based on, among other things, data and records detailing the operations and physical assets of Line 132; pipe specifications; gas flow data; pressure readings; historic pressure orders; sworn interviews and testimony regarding the September 9, 2010 accident; and third-party reports regarding the accident, including the Accident Report and Metallurgical Fact Reports published by the National Transportation and Safety Board (NTSB), and the January 12,

explained that the rupture on Segment 180 initiated at pup 1, which was missing an internal weld along its longitudinal seam.[274] A ductile tear initiated at the root of the externally welded longitudinal seam on pup 1,[275] and fatigue crack growth from the ductile tear over time ultimately resulted in the rupture.[276] Dr. Caligiuri testified that a ductile tear is caused by a single loading event.[277]

The record also shows that the NTSB examined and ruled out several potential causes of the ductile tear, including corrosion, seismic activity, and a 2008 sewer repair near the rupture location.[278] The NTSB also determined, and Dr. Caligiuri agreed, that because of the missing interior welds a hydro test conducted at a pipe mill would have caused pups 1, 2 and 3 to fail, and could not have been the cause of the ductile tear.[279] Dr. Caligiuri was able to rule out still other causes, such as external damage to the pipeline and a sudden pressure increase some time later than 1956.[280]

From his analysis, Dr. Caligiuri concluded that the most likely cause of the ductile tear on Segment 180 was a post-installation hydro test in 1956.[281] Under the standards in ASA B31.1.8-1955, a post-installation hydro test of Segment 180 in 1956, for a Class 2 location, would have been conducted at a pressure 1.25 times the MAOP, or 500 psig (1.25 x 400 psig).[282] Dr. Caligiuri determined that a hydro test pressure of approximately 500 psig would have been adequate to create the ductile tear in the longitudinal seam weld on pup 1, without causing the pipe to fail.[283]

2012 Incident Report by the Consumer Protection and Safety Division (CPSD) of the California Public Utilities Commission.").

[274] Ex. PG&E-1 at 3-5 to 3-7 (PG&E/Caligiuri).

[275] R.T. 1082-83 (PG&E/Caligiuri) (further explaining the meaning and mechanics of ductile tearing).

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

[277] Ex. PG&E-1 at 3-7 (PG&E/Caligiuri). ("A ductile tear is characterized by appreciable plastic deformation and energy dissipation, and is created by a single-loading event.").

[278] Ex. PG&E-1 at 3-14 to 3-15 (PG&E/Caligiuri); R.T. 1087 (PG&E/Caligiuri).

[279] Ex. PG&E-1 at 3-15 (PG&E/Caligiuri). ("Cold expansion in a pipe mill or a pipe mill hydro test could not have been the cause of the ductile tear since these activities would have produced stresses far greater than those required to burst the pup."); *id.* at 2-9 (PG&E/Harrison).

[280] Ex. PG&E-1 at 3-14 (PG&E/Caligiuri). ("PG&E has no record of pressures in Segment 180 ever approaching 500 psig during normal pipeline operation."); R.T.1088-89 (PG&E/Caligiuri).

[281] Ex. PG&E-1 at 3-16 to 3-17 (PG&E/Caligiuri).

[282] PG&E's Request for Official Notice, Ex. 5 (Ex. Records PG&E-47 (ASA B31.1.8) § 841.412(b) (1955)).

[283] Ex. PG&E-1 at 3-14 to 3-16 (PG&E/Caligiuri); *id.* at 3-16 (PG&E/Caligiuri) ("But for the missing interior weld, this post-installation hydro test would not have created the ductile tear. A pressure of approximately 500 psig was required to create the ductile tear, which is well above the 400 psig MAOP for Line 132, Segment 180.").

Even if a hydro test had been conducted at the pressure required for a Class 3 location, 1.40 times the MAOP, or 560 psig (1.40 x 400 psig), Dr. Caligiuri's conclusions are unchanged. Referring to the margins built into the applicable calculations, Dr. Caligiuri explained: "I think that it certainly changes some of the margins you have in there. But it does not change my opinion that if they had tested this section of pipe to 560 psi, I believe it's possible that those three pups would have survived." [284] As Dr. Caligiuri further explained, though the pipe section "was designed and constructed" with the expe ctation it would eventually be a Class 3 location, the pipe was not necessarily tested to a pressure of 560 psig.[285]

Aside from a post-installation hydro test, no other plausible cause of the ductile tear has been identified.[286] The NTSB found Dr. Caligiuri's conclusion credible:

> Q: [I]n your testimony you came to the conclusion that the ductile tear first occurred in 1956; is that right?
>
> A: I said that based on all the information I have, the best explanation I can come up with is the fact that it was the creation of that ductile tear by a hydro test in 1956. In fact, I discussed this with the NTSB when I was preparing this testimony, my observations and conclusions in that regard, and they found it credible. . . .[287]

CPSD proffered no evidence or analysis of its own that contradicted or undermined Dr. Caligiuri's testimony and conclusions. [288] CPSD relied on the NTSB's findings and CPSD's "beliefs."[289] CPSD's beliefs are not evidence. The NTSB did not offer a conclusion regarding how the ductile tear in pup 1 initiated, [290] but, as Dr. Caligiuri testified, the NTSB staff found his explanation credible. Apart from pointing out that PG&E does not have a record of a hydro test, CPSD lacks factual support for its contention that PG&E did not perform a hydro test on Segment 180.

[284] R.T. 1070-71 (PG&E/Caligiuri).

[285] R.T. 1068-69 (PG&E/Caligiuri).

[286] Ex. PG&E-1 at 3-14 (PG&E/Caligiuri).

[287] R.T. 1084 (PG&E/Caligiuri).

[288] Ex. CPSD-5 at 11-12 (CPSD/Stepanian).

[289] Ex. CPSD-5 at 12 (CPSD/Stepanian) ("However, CPSD believes that the pipe would likely have burst at500 psig test."); *id.* ("CPSD believes it is highly unlikely that Segment 180 was actually hydrostatically pressure tested.")

[290] Ex. CPSD-9 (NTSB Report) at 93 ("The NTSB investigation was unable to determine when or how the preexisting crack along the intact portion of the pup 1 longitudinal seam initiated.").

f. MAOP

CPSD alleges that "PG&E did not follow ASA B31.1.8 -1955 when it initially established the MAOP for the failed segment."[291] Although CPSD does not explain its claim, apparently it is based on the presence of the six unknown pups in Segment 180 and their lower than 52,000 psig tensile strengths as determined by the NTSB's 2011 metallurgical examination.

CPSD's claim is based on hindsight knowledge no one had in 1956, when PG&E first established the 400 psig MAOP for Segment 180. As Mr. Harrison explained, PG&E engineers did not know about the existence of the pups or their material specifications until after September 9, 2010. Thus the pup material properties established by the NTSB in 2011 could not possibly have been considered in determining the Line 132 MAOP. [292] Using information that came to light only after the accident does not provide a legitimate basis to allege that PG&E did not properly establish the Line 132 MAOP in 1956.

Regardless, the evidence demonstrates that the MAOP of 400 psig was appropriate when Segment 180 was installed.[293] MAOP can be established based on a design formula that, as Mr. Harrison testified, "takes into account the pipe's material characteristics such as SMYS, pipe diameter, wall thickness, and long joint f actor, and the 'construction type,' e.g., the class location."[294] In 1956, Segment 180 was in a Class 2 location, in 2010, Segment 180 was in a Class 3 location. Applying the design formula to the 52,000 psig SMYS DSAW pipe PG&E specified for Segment 180 yields a 780 psig MAOP for a Class 2 location and 650 psig for a Class 3 location, easily supporting the actual MAOP of 400 psig. [295] Even the hindsight knowledge from the NTSB's 2011 metallurgical work does not render the 400 psig MAOP inappropriate. The weakest pup in the NTSB analysis had a 32,000 psig SMYS. Applying the design formula to that tensile strength, the 1956 MAOP would have been 480 psig in a Class 2 location and 400 psig in a class 3 location.[296]

CPSD acknowledges that, since 1970, the 400 psig MAOP on Line 132 has been properly established under 49 C.F.R. § 192.619(c), "a requirement that became known as the grandfather

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[291] Ex. CPSD-1 at 23 (CPSD/Stepanian).

[292] Ex. PG&E-1 at 2-10 to 2-11 (PG&E/Harrison); Joint R.T. 324, 368, 415-25 (PG&E/Harrison).

[293] Ex. PG&E-1 at 2-10 to 2-11 (PG&E/Harrison).

[294] Ex. PG&E-1 at 2-10 (PG&E/Harrison) (citing ASA B31.1.8, § 845.22 (1955)).

[295] Ex. PG&E-1 at 2-10 to 2-11 (PG&E/Harrison);*id.* at 2-10 n.8 (PG&E/Harrison).

[296] Ex. PG&E-1 at 2-11 (PG&E/Harrison).

clause."[297] "At the time of the incident, the pressure on line 132 did not exceed the maximum pressure allowed by code."[298] When PG&E asked CPSD in a data request to identify any regulation, interpretation, guidance document or any other written statement by the Commission prior to September 9, 2010, that the grandfather clause was inadequate to protect public safety, CPSD responded that it was "not aware of any such documents at this time."[299]

CPSD has provided no legitimate factual or legal support for its claim that PG&E improperly established the MAOP on Line 132 at any time since 1956.

B. PG&E's Integrity Management Program

CPSD alleges the following violations of the integrity management regulations, 49 C.F.R. §§ 192.901 et seq. ("Subpart O") and ASME B31.8S -2004 ("ASME B31.8S"): (1) failing to conduct adequate data gathering and integration to evaluate potential threats to pipeline safety; (2) failing to adequately consider cyclic fatigue in its threat analysis; (3) failing to identify Segment 181 and other similar segments as having a potentially unstable manufacturing threat; and (4) failing to assess the integrity of Segments 180 and 181 (and other similar segments) with an appropriate assessment technology.[300]

In no area is it more apparent that CPSD is using a different lens after San Bruno than before than in its charges concerning PG&E's Integrity Management program. When CPSD, along with PHMSA, audited PG&E's Integrity Management program in 2005 and 2010, it did not identify or claim any of the violations it now asserts.[301] CPSD conducted its last pre-San Bruno audit in May 2010, and sent the report of its audit to PG&E six weeks after the accident.

CPSD does not suggest that PG&E's Integrity Management program suddenly went out of compliance after the May 2010 audit. CPSD failed to disprove its prior audit results and to prove its current allegations. Even with knowledge only available after the accident, CPSD did

[297] Ex. CPSD-1 at 23-24 (CPSD/Stepanian) (CPSD notes, in accordance with 49 C.F.R. § 192.619(a)(3), PG&E relied on a pressure log from the Milpitas Terminal dated October 16, 1968, to establish the MAOP of 400 psig for Line 132).
[298] Ex. CPSD-1 at 24 (CPSD/Stepanian).
[299] Ex. PG&E-1 at 2-11 (PG&E/Harrison).
[300] Ex. CPSD-1 at 163 (CPSD/Stepanian).
[301] The 2005 audit results are Ex. PG&E-7 (Tab 4-25), and the 2010 audit results are Ex. PG&E-7 (Table 4-13). CPSD conducted each audit pursuant to the then-current PHMSA audit protocols.

not present evidence that PG&E's pre-San Bruno practices and actions violated the requirements of the integrity management regulations.

1. CPSD Did Not Prove PG&E's Data Gathering And Integration Procedures Violated The Law

CPSD alleges that "[t]here were a number of deficiencies in PG&E's data gathering and analysis process, that resulted in a flawed understanding of Line 132 HCA segments."[302] According to CPSD, these alleged deficiencies are (a) failure to conduct a thorough data gathering, and specifically the failure to gather relevant leak data on Line 132;[303] and (b) failure to ensure the quality and accuracy of data in its Geographic Information System (GIS), including purported failure to apply sufficiently conservative assumed values.[304]

CPSD's May 2010 audit reached the opposite conclusion in each of these areas. In the area of data gathering and integration, in May 2010 CPSD identified only three minor shortcomings: CPSD concluded PG&E did not integrate equipment data in its evaluation of equipment failure threat, did not integrate patrolling records into GIS, and did not enter USA information into GIS.[305] The following are the relevant excerpts from the 2010 audit protocol completed by CPSD before the accident:

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302 Ex. CPSD-1 at 26 (CPSD/Stepanian).

303 Ex. CPSD-1 at 30 (CPSD/Stepanian).

304 Ex. CPSD-1 at 30-32 (CPSD/Stepanian). CPSD also alleges that PG&E violated the law for failing to "consider known longitudinal cracks in Line 132 dating to the 1948 construction and at least one longitudinal seam leak in a DSAW weld in its identifi cation and assessment procedures." While CPSD characterizes this as a data gathering issue, it is more appropriately addressed as a question of threat identification.

305 Ex. PG&E-7 (Tab 4-13) at 38-40.

C.02 Data Gathering and Integration

Verify that the operator gathers and integrates existing data and information on the entire pipeline that could be relevant to covered segments, and verify that the necessary pipeline data have been assembled and integrated. [§192.917(b)]

C.02.a. Verify that the operator has in place a comprehensive plan for collecting, reviewing, and analyzing the data. [ASME B31.8S-2004, Section 4.2 and ASME B31.8S-2004, Section 4.4]

C.02.a. Inspection Results *(Type an X in the applicable box below. Select only one.)*	
	No Issues Identified
X	Potential Issues Identified *(explain in Statement of Issue)*
	Not Applicable *(explain in Statement of Issue)*

C.02.a. Statement of Issue *(Leave blank if no issue is identified. In addition to stating the issue, indicate the Issue Category and supporting evidence for each issue. Number multiple issues, e.g., 1, 2, 3, etc. There must be a one-to-one correlation between issues and issue categories. No issue should be related to more than one issue category. No issue category should be related to more than one issue.)*
PG&E has identified Equipment Failure as a threat, although it's unclear how this threat is assessed and/or if previous equipment related data has been integrated into the BAP. PG&E RMP-06, Section 2.4, mentions a procedure for determining equipment threat; however, the procedure doesn't exist according to PG&E. PG&E did not integrate equipment data in BAPs established in 2004.

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C.02.b. Verify that the operator has assembled data sets for threat identification and risk assessment according to the requirements in ASME B31.8S-2004, Section 4.2, ASME B31.8S-2004, Section 4.3, and ASME B31.8S-2004, Section 4.4. At a minimum, an operator must gather and evaluate the set of data specified in ASME B31.8S-2004, Appendix A (summarized in ASME B31.8S-2004, Table 1) and consider the following on covered segments and similar non-covered segments [§192.917(b)]:

1. Past incident history
2. Corrosion control records
3. Continuing surveillance records
4. Patrolling records
5. Maintenance history
6. Internal inspection records
7. All other conditions specific to each pipeline.

C.02.b. Inspection Results *(Type an X in the applicable box below. Select only one.)*	
	No Issues Identified
X	Potential Issues Identified *(explain in Statement of Issue)*
	Not Applicable *(explain in Statement of Issue)*

C.02.b. Statement of Issue *(Leave blank if no issue is identified. In addition to stating the issue, indicate the Issue Category and supporting evidence for each issue. Number multiple issues, e.g., 1, 2, 3, etc. There must be a one-to-one correlation between issues and issue categories. No issue should be related to more than one issue category. No issue category should be related to more than one issue.)*

It does not appear that PG&E has integrated patrolling records into its GIS.

C.02.c. Verify that the operator has utilized the data sources listed in ASME B31.8S-2004, Table 2, for initiation of the integrity management program. [ASME B31.8S-2004, Section 4.3]

C.02.c. Inspection Results *(Type an X in the applicable box below. Select only one.)*	
X	No Issues Identified
	Potential Issues Identified *(explain in Statement of Issue)*
	Not Applicable *(explain in Statement of Issue)*

C.02.e. Verify that the operator's program includes measures to ensure that new information is incorporated in a timely and effective manner, as addressed in Protocol K. [§192.911(k), ASME B31.8S-2004, Section 11(b) and ASME B31.8S-2004, Section 11(d)]

C.02.e. Inspection Results *(Type an X in the applicable box below. Select only one.)*	
X	No Issues Identified
	Potential Issues Identified *(explain in Statement of Issue)*
	Not Applicable *(explain in Statement of Issue)*

C.02.f. Verify that individual data elements are brought together and analyzed in their context such that the integrated data can provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk. [ASME B31.8S-2004, Section 4.5]. Data integration includes:

i. A common spatial reference system that allows association of data elements with accurate locations on the pipeline [ASME B31.8S-2004, Section 4.5];
ii. Integration of ILI or ECDA results with data on encroachments or foreign line crossings in the same segment to define locations of potential third party damage [§192.917(e)(1)].

C.02.f. Inspection Results *(Type an X in the applicable box below. Select only one.)*	
	No Issues Identified
X	Potential Issues Identified *(explain in Statement of Issue)*
	Not Applicable *(explain in Statement of Issue)*

C.02.f. Statement of Issue *(Leave blank if no issue is identified. In addition to stating the issue, indicate the Issue Category and supporting evidence for each issue. Number multiple issues, e.g., 1, 2, 3, etc. There must be a one-to-one correlation between issues and issue categories. No issue should be related to more than one issue category. No issue category should be related to more than one issue.)*
PG&E is not currently entering USA information into its GIS, nor is it entering any patrol findings that could impact transmission pipelines. (PHMSA FAQ-81 requires: "Information related to determining the potential for, and preventing damage due to excavation, including damage prevention activities..." be integrated in performing a continual evaluation of pipeline integrity.) PHMSA FAQ-240 (paragraph 4) also speaks to this, as well as ASME B31.8S, Section A7.2 also requires one-call to be integrated.

Contrary to CPSD's post -San Bruno claims, the evidence shows PG&E's Integrity Management procedures provided for appropriate gathering and integration of all data elements necessary to perform threat identification and risk assessment. As John Zurcher (a long-time member of ASME's B31.8 Section Committee involved in revising and issuing interpretations of ASME B31.8S) testified, PG&E's GIS and its data gathering and analysis practices were consistent with the requirements of integrity management regulations, ASME B31.8S requirements, and industry practice.[306]

a. PG&E Adequately Gathered The Data Elements Required By The Integrity Management Regulations And ASME B31.8S

(i) PG&E's Data Gathering Process Incorporates The Data Elements Specified By ASME B31.8S

Data gathering is part of the integrity management threat identification process. 49 C.F.R. § 192.917(b). ASME B31.8S sets forth minimum data sets a prescriptive integrity

[306] Ex. PG&E-1 at 5-6 to 5-14 (PG&E/Zurcher).

management program like PG&E's must gather.[307] As CPSD found in its 2010 audit,[308] PG&E's practices and procedures call for each of these data elements to be gathered. [309] CPSD, however, focused on a phrase in PG&E's procedure rather than analyze PG&E's whole procedure and practices. CPSD claims that la nguage in PG&E's procedure calling for information that can be obtained in a "timely manner" " *suggests* that a thorough data gathering and integration was not performed[.]"[310] CPSD's inference is not evidence. CPSD does not identify any specific data set PG&E failed to gather, and instead attempts to support its conclusion by reference to a brief (and inaccurate) portion of the NTSB report relating to leak data.[311]

Contrary to CPSD's assumption that the "timely" qualifier led PG&E to omit from consideration minimum data elements identified by ASME B31.8S, this section of RMP-06 simply reflects a yearly data gathering and threat identification process. [312] PG&E's data gathering consists of a two-step process that ensures PG&E can conduct its threat identification on the annual basis required by the regulations, while also verifying the initial data collection through field-based data review. [313] The first step is an initial data gathering and threat identification performed using centralized pipeline attribute data sets in PG&E's GIS.[314] These data sets are geographically integrated with data relating to conditions surrounding the pipeline.[315] For example, to perform the construction threat identification process, PG&E identified pipe segments that are potentially subject to the construction threat due to girth weld methods or girth joint configurations. [316] PG&E then reviewed the potential for ground movement, which activates the construction threat, by overlaying the at-risk pipe segments with geographic regions that are subject to ground movement. [317] The record shows that PG&E

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307 Joint R.T. 1186 (PG&E/Keas) (PG&E follows the prescriptive approach provided by ASME B31.8S); Ex. CPSD-1 at 28 (CPSD/Stepanian).

308 Ex. PG&E-7 (Tab 4-13).

309 Ex. PG&E-1c at 4-8 (PG&E/Keas); Joint R.T. 750-51, 796-98 (PG&E/Zurcher); Joint R.T. 970, 1082 (PG&E/Keas).

310 Ex. CPSD-1 at 30 (CPSD/Stepanian) (emphasis added).

311 CPSD refers to the NTSB Final Report (Ex. CPSD-9), Section 2.6.1, pages 109-110, which states that PG&E failed to integrate closed leak data into its GIS, such as the 1988 leak (discussed below).

312 Joint R.T. 1081-82 (PG&E/Keas).

313 Ex. PG&E-1c at 4-8 (PG&E/Keas); Joint R.T. 1176-77 (PG&E/Keas).

314 Ex. PG&E-1c at 4-7 (PG&E/Keas).

315 Ex. PG&E-1c at 4-7 (PG&E/Keas).

316 Ex. PG&E-1c at 4-7 (PG&E/Keas).

317 Ex. PG&E-1c at 4-7 (PG&E/Keas).

performed this initial data gathering for all nine categories of pipeline threats, using the minimum data elements outlined in ASME B31.8S.[318]

PG&E's RMP -06 describes the data used in this first step as "available, verifiable information or information that can be obtained in a timely manner."[319] This statement reflects the fact that threat identification is conducted at least once per year, and any data used must be available at the time of the gathering process. As PG&E Risk Management Supervisor Kris Keas testified:

> [T]he data gathering process happens on an annual basis. And so at some point you think that you've gotten all the data put together, and it's your best effort based upon your understanding of the system that you have. And you need to complete the assessment recognizing that as new data comes in the following year, you would take new data that comes in to – and incorporate that into your new data collection process or your next data collection process…Somebody could do an inspection on a pipeline that's existing, and that new record may produce information regarding attribute information and the condition information that is just now documented.[320]

Data elements from other sources that were not readily gathered and integrated into GIS (e.g., construction records in job files or leak records in local offices) would be reviewed during the second step in the data gathering process.[321] The second step occurs during the pre-assessment phase of each integrity assessment.[322] During the pre-assessment phase of both in-line inspections (ILI) and direct assessments (e.g., ECDA), PG&E's practices call for an integrity management engineer to conduct additional data gathering from field offices and other distributed information sources.[323] Pre-assessment data gathering is performed on all nine threat categories.[324] This data-gathering step involved analyzing job files, interviewing employees responsible for maintenance on the pipe segment, and conducting a review of records in local Division and District offices to develop a qualitative understanding of the maintenance history

[318] Ex. PG&E-1c at 4-7 to 4-9 (PG&E/Keas); Joint R.T. 1081-82 (PG&E/Keas).
[319] Ex. PG&E-6 (Tab 4-6) (RMP-06, § 2.4).
[320] Joint R.T. 1081-82 (PG&E/Keas).
[321] Joint R.T. 1075 (PG&E/Keas).
[322] Ex. PG&E-1c at 4-8 (PG&E/Keas).
[323] Ex. PG&E-1c at 4-8 (PG&E/Keas).
[324] Joint R.T. 1176-79 (PG&E/Keas).

and characteristics of the pipeline that was to be assessed. [325] Information gathered during this process is analyzed to determine what effect it had, if any, on the integrity assessment process and assessment tool selection, specifically whether the chosen assessment method could adequately address the pipeline threats identified for a particular pipeline segment.[326]

As the evidence shows, taken together the components of PG&E's data gathering process incorporated the elements required by ASME B31.8S Appendix A.[327]

When John Zurcher was asked the basis for his opinion that PG&E's procedures for data gathering and integration were consistent with industry standards and regulation requirements, Mr. Zurcher testified:

> . . . I have looked at 50 to 60 different companies' integrity management programs. I know what they are saying. PG&E's lines up with all these programs. I've also been invol ved with the development of the standards that address integrity management. In my opinion, PG&E's practices are consistent with that standard. I've also looked at their standards in reference to the pipeline safety regulations and believe that they are consistent with regulatory requirements for integrity management.[328]

CPSD failed to introduce credible evidence to the contrary, and accordingly cannot establish a violation of law relating to PG&E's data gathering procedures.

(ii) CPSD Did Not Prove PG&E Failed To Gather Required Leak Data

CPSD asserts that PG&E's data gathering process failed to gather "all data on leaks as cited in the NTSB Report." [329] CPSD's allegation ignores CPSD's own 2010 audit of PG&E's Integrity Management program. It is instead based o n section 2.6.1 of the NTSB's Pipeline Accident Report titled "PG&E GIS and Pipeline Record-keeping," which contained the results of the NTSB's view of PG&E's GIS system. [330] However, PG&E has historically maintained leak

[325] Ex. PG&E-1c at 4-8 (PG&E/Keas). *See also* Ex. PG&E-6 (Tab 4-8) (RMP-09, § 3.3); Ex. PG&E-6 (Tab 4-10) (RMP-11, § 3.3).
[326] Joint R.T. 1176-77 (PG&E/Keas).
[327] Ex. PG&E-1c at 4-8 (PG&E/Keas).
[328] Joint R.T. 797-98 (PG&E/Zurcher).
[329] Ex. CPSD-1 at 30 (CPSD/Stepanian).
[330] Ex. CPSD-9 (NTSB Report) at 108-09.

records in hard copy form,[redacted] so it is neither surprising nor probative that not all leaks are in GIS. The hard copy records are kept in job files or in "leak libraries" at approximately 70 local field offices.[redacted] Prior to San Bruno, PG&E had transferred some leak data into its GIS.[redacted] This partial data set included leaks recorded on historic pipeline survey sheets and leaks in the Integrated Gas Information System (IGIS) leak repair tracking database, but was by no means intended to make GIS the complete repository of all hardcopy leak records.[334] PG&E's Integrity Management procedures recognize that leak data sets beyond GIS existed, and call for the gathering of information from leak records from local offices during the second step of the data gathering process.[335] Having failed to consider PG&E's incorporation of hardcopy data, and having introduced no independent evidence to support its allegations, CPSD cannot establish a violation of law relating to PG&E's gathering of leak data.

b. CPSD Failed To Establish A Legal Or Factual Basis For Its Claim That The Quality Of PG&E's GIS Data Violated The Law

CPSD asserts PG&E's Integrity Management program failed to meet regulatory standards because the program made use of assumed values, because such values were allegedly insufficiently conservative, and for purported failure to review the quality and consistency of GIS data.[336] The evidence shows that each claim fails.

(i) CPSD Did Not Prove That PG&E's Use Of Assumed Values Violated Any Law

Contrary to CPSD's assertion, PG&E's use of conservative assumed values comports with integrity management regulations and common industry practice. PG&E, like nearly every gas pipeline operator, did not have confirmed pipeline specifications for every attribute of every

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[redacted]

334 [redacted] Following San Bruno, PG&E has undertaken to gather all leak records from local offices and create a central data set of transmission leaks to assist Integrity Management personnel during data gathering. Joint R.T. 1203 (PG&E/Keas).

335 *See, e.g.*, Ex. PG&E-6 (Tab 4-8) (RMP-09 Procedure for External Corrosion Direct Assessment) at 18.

336 Ex. CPSD-1 at 31 (CPSD/Stepanian).

segment in its operating system at the time it created its GIS. [337] Where PG&E lacked data that was relevant to integrity management decisions, PG&E made measured use of conservative assumed values in accordance with ASME B31.8S. [338] Mr. Zurcher articulated how operators used assumed values in compliance with the regulations:

> Conservative assumed values means that you are relying on other documentation for either vintage issues or other documentation about a specific project and using those values as conservative values rather where you may be missing specific mill test certifications or other material information.[339]

Prior to the San Bruno accident, PG&E researched historic pipe procurement and construction documentation to identify the minimum pipe specifications (e.g., SMYS values) PG&E used during various eras. [340] This research allowed PG&E to make conservative assumptions regarding the pipe characteristics based upon the year of installation and the diameter of pipe.[341] PG&E's practice has been to use the most conservative specifications (e.g., lowest SMYS value) from Company material procurement specifications for pipeline projects installed during the same time period as the pipe segment in question. [342] This practice has explicit support in ASME B31.8S, is consistent with industry norms, and allows PG&E to properly prioritize pipeline segments for assessment in PG&E's risk evaluation process. [343] As Mr. Zurcher testified:

> [T]here are basically three different ways to get to the value of SMYS. One is to actually have mill certification records [that] would state it. That would be one method. There is a second series of methods which include the operator having the pipe specification or having the actual pipe purchase order or having the

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[337] *See, e.g.*, Joint R.T. 21-22 (PG&E/Zurcher) ("I have looked at records of a hundred different pipeline companies across the U.S., and everybody, as a good industry practice, as you mentioned, everybody is in the same situation. There are records that are either missing or assumed values that – assumed values that they had to use in order to comply with it."); *id.* at 662-63 (PG&E/Zurcher).

[338] Ex. PG&E-1c at 4-9 (PG&E/Keas).

[339] Joint R.T. 36 (PG&E/Zurcher).

[340] Ex. PG&E-1c at 4-10 (PG&E/Keas); Joint R.T. 979 (PG&E/Keas).

[341] Ex. PG&E-1c at 4-10 (PG&E/Keas); Joint R.T. 979 (PG&E/Keas).

[342] Ex. PG&E-1c at 4-9 (PG&E/Keas).

[343] *See, e.g.*, Joint R.T. 1186-87 (PG&E/Keas); Ex. Joint-28 (ASME B31.8S) Appendix A, § 4.2 (2004) ("Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher."); Ex. PG&E-1c at 4-10 (PG&E/Keas); Ex. PG&E-1 at 5-7 to 5-8 (PG&E/Zurcher).

> actual as-built notes as they are received after construction. Those all then meet into one second category.
>
> The third category is to look up through the history of line pipe, the Kiefner report, and actually look and see what was manufactured for a given year by a given manufacturer. All those to me are acceptable methods of assumptions of SMYS, conservative, fact-based assumptions on SMYS.[344]

Nonetheless, CPSD contends that PG&E's use of assumed SMYS values higher than 24,000 psig, under any circumstances, violated pipeline regulations. CPSD does not identify specific segments i t claims are at issue, but asserts "Two segments with unknown SMYS were assigned non-conservative values of 33,000 psi and 52,000 psi, although Part 192.107(b)(2) requires a conservative value of 24,000 psi when the exact SMYS of a pipe segment is not known or documented."[345] The evidence shows otherwise. As discussed above, and during the joint hearing with the Class Location OII, using assumed values based on other documentation where an operator lacks specific information regarding a pipe segment's SMYS is both consistent with the regulations and common across the pipeline industry.[346] Mr. Zurcher explained that the 24,000 psig SMYS value only applies where the operator has *no information* to support a more accurate SMYS value:

> If you have no information about that pipe [then you have to use 24,000 psig SMYS], but there's degrees of known information. I think that's why I keep going back to that word that they use in both the standard and in the regulations about unknown. What do you mean by unknown. And I know that most companies interpret the unknown as a very specific and very finite term.
>
> Known would be that I have similar specifications at a similar time or I have purchase orders or I have pipeline specifications or I have as-built drawings that have all of that information on it.[347]

CPSD has not produced evidence to substantiate its claim that PG&E's use of assumed SMYS values violated the law. Rather, though not its burden, PG&E presented evidence that proved PG&E's practice was appropriate and complied with the regulations.[348]

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[344] Joint R.T. 15-16 (PG&E/Zurcher).

[345] Ex. CPSD-1 at 31 (CPSD/Stepanian). CPSD's allegations are based entirely on statements in the NTSB Pipeline Accident Report, and contain no additional substantiation.

[346] Joint R.T. 9 (PG&E/Zurcher).

[347] Joint R.T. 28-29 (PG&E/Zurcher).

CPSD also faults PG&E for using three SMYS values for pipe segments identified as "Grade B" pipe. In support, CPSD reiterates an observation from the NTSB report that PG&E's GIS reflected SMYS values of 35,000 psig, 40,000 psig and 45,000 psig for Grade B pipe.[349] Again, CPSD's assertion fails for lack of evidence. Rather than examine PG&E's historic pipe purchasing practices, research historic pipe manufacturing processes, or otherwise demonstrate that Grade B pipe *cannot* have a SMYS value higher than 35,000 psig, CPSD merely states "as far as the CPSD can determine, all API Grade B pipe has a minimum yield strength of 35,000 psi."[350] The evidence proves CPSD's presumption is wrong. Mr. Zurcher testified that Grade B pipe commonly has a SMYS value of 35,000 psig, but was also available at intermediate grades above this value at the request of the pipeline operator.[351]

(ii) CPSD Did Not Prove A Violation Of Law In PG&E's Review Of GIS Data Accuracy

CPSD alleges that PG&E failed to adequately review the accuracy of its GIS data, as evidenced by: (1) the fact that PG&E did not recognize the erroneous 30-inch seamless pipe designation for Segment 180, and (2) the fact that GIS did not reflect the presence of six short lengths of pipe in Segment 180.[352] Neither claim establishes a violation of law, and CPSD's

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[348] Were PG&E to use lower SMYS values (as CPSD contends it should have) instead of the actual characteristics of the pipe the Company purchased in the relevant time period, these pipe segments would receive artificially inflated risk scores, and could be assessed before other higher- risk pipe segments. PG&E's use of conservative assumed values is consistent with the threat identification process. Where PG&E is lacking data on a certain pipeline attribute, PG&E has applied a conservative assumed value derived from historic pipe purchasing practices, or where such information is not available, assumes that the particular threat potentially exists. For example, in conducting data gathering for the manufacturing threat analysis, PG&E looks to the elements identified in ASME B31.8S, Appendix A (as required for operators who maintain a prescriptive integrity management program). The seam type is one of the elements that must be gathered and considered. Ex. Joint-28 (ASME B31.8S), Appendix A, § 4.2 (2004). Where PG&E does not have records sufficient to identify the seam type, its practice is to assume that a potential manufacturing seam threat exists, and to continue with a stability analysis to determine whether the segment must be assessed using in-line inspection or hydro testing. Joint R.T. 990, 1179-81 (PG&E/Keas). Thus, PG&E's measured use of conservative, assumed values informed by pipe procurement specifications increases the effectiveness of its risk assessments and the Company's Integrity Management program as a whole. Ex. PG&E-1c at 4-9 to 4-10 (PG&E/Keas).

[349] Ex. CPSD-1 at 31 (CPSD/Stepanian).

[350] Ex. CPSD-5 at 15 (CPSD/Stepanian).

[351] Joint R.T. 53 (PG&E/Zurcher).

[352] Ex. CPSD-1 at 32 (CPSD/Stepanian). CPSD also alleges violations based on GIS values for six segments on Line 132 with an erroneous depth of cover of 40 feet. PG&E believes that this is a simple data entry error (4.0 feet is a common depth of cover).

claim that PG&E did not adequately check its data for accuracy is contradicted by CPSD's 2010 audit finding:[353]

C.02.d. Verify that the operator has checked the data for accuracy. If the operator lacks sufficient data or where data quality is suspect, verify that the operator has followed the requirements in ASME B31.8S-2004, Section 4.2.1, ASME B31.8S-2004, Section 4.4, and ASME B31.8S-2004, Appendix A [ASME B31.8S-2004, Section 4.1, ASME B31.8S-2004, Section 4.2.1, ASME B31.8S-2004, Section 4.4, ASME B31.8S-2004, Section 5.7(e), and ASME B31.8S-2004, Appendix A]:

i. Each threat covered by the missing or suspect data is assumed to apply to the segment being evaluated. The unavailability of identified data elements is not a justification for exclusion of a threat.
ii. Conservative assumptions are used in the risk assessment for that threat and segment or the segment is given higher priority.
iii. Records are maintained that identify how unsubstantiated data are used, so that the impact on the variability and accuracy of assessment results can be considered.
iv. Depending on the importance of the data, additional inspection actions or field data collection efforts may be required.

C.02.d. Inspection Results *(Type an X in the applicable box below. Select only one.)*	
X	No Issues Identified
	Potential Issues Identified *(explain in Statement of Issue)*
	Not Applicable *(explain in Statement of Issue)*

As PG&E now knows, the information in GIS on September 9, 2010 that Segment 180 contained 30-inch seamless pipe was inaccurate; seamless pipe of that diameter was not available when Segment 180 was installed. However, CPSD's contention that PG&E's Integrity Management engineers should have identified a 1956 30-inch seamless pipe as a historical impossibility requiring additional research is not supported by the evidence.[354] As PG&E witness Kris Keas explained:

> At that time, there's such a variability in the diameters and there's such a variability in the type of pipeline manufacturers and pipe attributes that it wasn't considered a flag. This was kind of identified as after the fact after we have a better understanding of the history of line pipe manufacturing in North America. . . Like I said, we are using records from a very large period of time. We see quite a bit of variability in the diameters and quite a bit of variability in manufacturing methods employed in different era[s]. Because of that, we didn't recognize that 30 -inch seamless was not a manufacturing methodology employed in the 1950s.[355]

[353] Ex. PG&E-7 (Tab 4-13) at 39.
[354] Joint R.T. 1028-31 (PG&E/Keas).
[355] Joint R.T. 1028-31 (PG&E/Keas).

Given the proliferation of pipe diameter and seam type combinations over the past decades, there is no reasonable factual basis – and CPSD has not provided any – to assert that the Segment 180 seamless designation in PG&E's GIS should have singularly stood out from among the other thousands of GIS entries.

By this allegation, CPSD seeks to retroactively impose standards far exceeding pre-incident interpretations of the integrity management rules and common industry practice. As John Zurcher (who helped write the integrity management regulations) testified, operators did not interpret the integrity management rules to mandate that they recreate pipeline data from original construction records, many of which went back decades, and it was common industry practice to accept the accuracy of preexisting pipeline data collections, such as pipeline survey sheets and GIS.[356] Describing his personal experience implementing GIS systems for pipeline operators, Mr. Zurcher explained:

> I will tell you in personal experience in all the companies I have worked with and the two GIS systems I built, we never once went beyond what you would have called these survey sheets. Every company had them. We just took the data that we had available. We did not go back ever and research any other type of data.
>
> Again, as we would find errors in the data, those would get corrected. But I don't know of a single company that went back to try to resurrect original type data for anything. It was just a movement from one record system to another.[357]

PG&E's development and use of information from GIS for its integrity management data gathering was consistent with common industry practices and industry understanding that regulatory requirements allowed them to rely on their prior data gathering efforts, rather than starting anew.[358] CPSD has presented no evidence to support a conclusion that the identification of 30-inch seamless pipe manufactured in 1956 – now known to be erroneous – reflects a legally deficient effort by PG&E to ensure the accuracy of its GIS system. To accept CPSD's position is to conclude that *any single data error* among several millions of data entries constitutes a violation of law.

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[356] Ex. PG&E-1 at 5-7 (PG&E/Zurcher). Exhaustive research efforts going back decades and reviewing every document, like PG&E's post-accident MAOP validation project, are unprecedented.

[357] Joint R.T. 663 (PG&E/Zurcher).

[358] Ex. PG&E-1 at 5-4 to 5-8 (PG&E/Zurcher); Joint R.T. 663 (PG&E/Zurcher).

Similarly, the fact that PG&E's GIS system did not reflect the presenc e of six defective pipe sections (the pups) in Segment 180 is not a question of data gathering, data quality, or recordkeeping; it is the result of improperly-manufactured pipe unknowingly installed by PG&E half a century prior to implementation of the integrity management rules. [359] No construction document describing the condition and installation of the pups would ever have been created for the simple reason that defective pipe would not have been knowingly installed.[360]

The evidence also shows that the Segment 180 records provided no reason for PG&E to suspect the presence of the pups. Procurement records indicate that PG&E ordered from inventory X52, 0.375-inch DSAW pipe for Segment 180, the majority of which was likely delivered to the job site already wrapped. [361] PG&E's job file for Segment 180 contains specific information and drawings down to the level of detail of tie-in drawings showing pieces of pipe and the location of elbows. [362] Had PG&E intentionally installed short pipe sections (for example, to negotiate a change in direction or elevation), PG&E would expect to have reflected this fact in the Segment 180 construction documents. [363] However, no drawing in the job file contains any such depiction, and the evidence shows that the rupture location did not involve a change in direction or elevation requiring short pipe pieces. [364] The necessary conclusion from the evidence is that PG&E "had no idea [the pups] existed" from the date of their installation. [365] Moreover, recordkeeping provisions in industry standards from the time of the installation (ASA B.31.1.8-1955) did not address the creation and maintenance of records of pipeline installations, much less to the level of detail that would reflect the installation of six pups of the sort contained in Segment 180. [366] CPSD's claim that PG&E's GIS was legally deficient because it did not

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[359] Joint R.T. 421 (PG&E/Harrison).

[360] Joint R.T. 394 (PG&E/Harrison) ("And we don't believe the pipe ever would have been installed if they had actually seen the pipe."); *id.* at 337-38 (PG&E/Harrison).

[361] Joint R.T. 253 (PG&E/Harrison).

[362] Joint R.T. 253 (PG&E/Harrison); *see generally* Ex. Joint-10.

[363] Joint R.T. 368 (PG&E/Harrison).

[364] Joint R.T. 342-43 (PG&E/Harrison); Ex. CPSD-9 (NTSB Report) at 40; Ex. CPSD-16 at 15 (chord lengths of pups indicating only minor angles).

[365] Joint R.T. 368 (PG&E/Harrison).

[366] Ex. PG&E-1 at 7-1, n.1 (PG&E/Harrison). ASA B31.1.8-1955 addressed pressure test records (841.417), operation and maintenance procedures (850.3(c)), welding qualification records (824.25), corrosion records (851.4) and leak records (851.5), but not construction records.

identify the (unknown) pups in Segment 180 is not supported by the evidence or any applicable regulation or standard.[367]

2. CPSD Did Not Prove That PG&E Failed To Evaluate Cyclic Fatigue As Required By The Law

CPSD alleges that PG&E violated integrity management regulations (49 C.F.R. §192.917(e)(2)) by failing to adequately evaluate the threat posed by cyclic fatigue.[368] In 2010, however, when CPSD audited PG&E's Integrity Management program, CPSD found PG&E's consideration of cyclic fatigue and all other threats except equipment failure and hard spots to be satisfactory:[369]

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[367] Maintaining joint-by-joint detail regarding pipeline installations is not a standard that even exists today in the industry. Joint R.T. 487 (PG&E/Harrison).

[368] Ex. CPSD-1 at 50 (CPSD/Stepanian).

[369] Ex. PG&E-7 (Tab 4-13) at 35-37.

C.01 Threat Identification

Verify that the operator identifies and evaluates all potential threats to each covered pipeline segment. [§192.917(a)]

C.01.a. If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated: [§192.917(a) and ASME B31.8S-2004, Section 2.2]

i. external corrosion,
ii. internal corrosion,
iii. stress corrosion cracking;
iv. manufacturing-related defects, including the use of low frequency electric resistance welded (ERW) pipe, lap welded pipe, flash welded pipe, or other pipe potentially susceptible to manufacturing defects [§192.917(e)(4) and ASME B31.8S-2004, Appendix A4.3];
v. welding- or fabrication-related defects,
vi. equipment failures;
vii. third party/mechanical damage [§192.917(e)(1)],
viii. incorrect operations (including human error),
ix. weather-related and outside force damage,
x. cyclic fatigue or other loading condition [§192.917(e)(2)],
xi. all other potential threats.

C.01.a. Inspection Results *(Type an X in the applicable box below. Select only one.)*	
	No Issues Identified
X	Potential Issues Identified *(explain in Statement of Issue)*
	Not Applicable *(explain in Statement of Issue)*

C.01.a. Statement of Issue *(Leave blank if no issue is identified. In addition to stating the issue, indicate the Issue Category and supporting evidence for each issue. Number multiple issues, e.g., 1, 2, 3, etc. There must be a one-to-one correlation between issues and issue categories. No issue should be related to more than one issue category. No issue category should be related to more than one issue.)*
Protocol C.01.a.xi requires "all other potential threats" be identified and evaluated; however, PG&E has not developed a process for evaluating the threat of equipment failure and is not mandating hard spots (RMP-06, Section 3) to be assessed, although they have been identified as a possible threat, before considering assessment or mitigation efforts are completed. 49 CFR §192.917(a) states in part: "An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME…" Per 49 CFR §192.917(c), an operator must conduct a risk assessment that considers the threats and aids in prioritizing the covered segment for the baseline and

C.01.a. Statement of Issue *(Leave blank if no issue is identified. In addition to stating the issue, indicate the Issue Category and supporting evidence for each issue. Number multiple issues, e.g., 1, 2, 3, etc. There must be a one-to-one correlation between issues and issue categories. No issue should be related to more than one issue category. No issue category should be related to more than one issue.)*
continual assessments. For equipment threats, ASME B31.8S, Section A6.2 (page 49) specifies minimal data sets to be collected and reviewed before a risk assessment can be conducted. PG&E has not collected this data set, nor attempted to identify particular equipment threats on any given segment.

C.01.c. Verify that the operator's threat identification has considered interactive threats from different categories (e.g., manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage) [ASME B31.8S-2004, Section 2.2].

C.01.c. Inspection Results *(Type an X in the applicable box below. Select only one.)*	
X	No Issues Identified
	Potential Issues Identified *(explain in Statement of Issue)*
	Not Applicable *(explain in Statement of Issue)*

C.01.d. Verify that the approach incorporates appropriate criteria for eliminating a specific threat for a particular pipeline segment. [ASME B31.8S-2004, Section 5.10]

C.01.d. Inspection Results *(Type an X in the applicable box below. Select only one.)*	
X	No Issues Identified

CPSD's current allegation finds no support in the law and disregards the prevailing industry, engineering and regulatory perspective prior to the San Bruno incident that the threat of cyclic fatigue-induced failure in natural gas pipelines was essentially non-existent. A segment-by-segment analysis of PG&E's entire transmission system woul d not have identified Line 132, Segment 180 as susceptible to cyclic fatigue within the expected useful life of the segment. CPSD did not and cannot meet its burden of establishing that PG&E's evaluation of the threat posed by cyclic fatigue was a violation of law.

a. Prior To San Bruno, The Gas Pipeline Industry Understood The Threat Of Failure Of Natural Gas Pipelines Due To Cyclic Fatigue To Be Negligible

The evidence demonstrates beyond question that cyclic fatigue was not considered a threat to natural gas pipelines before September 9, 2010. There had been no recorded failures from cyclic fatigue on natural gas pipelines.[370] Gas operators and regulators simply did not view cyclic fatigue as a significant threat to their systems.

PG&E witness John Kiefner, widely regarded as the pre-eminent expert regarding cyclic fatigue in pipelines, testified regarding efforts by regulators and the natural gas industry following implementation of the integrity management rules to investigate the threat posed by cyclic fatigue and what steps an operator could take to address this threat. A cornerstone of this effort was Dr. Kiefner's 2004 study investigating the effects of pressure cycles on natural gas

[370] R.T. 716 (PG&E/Kiefner).

pipelines.[371] The objective of the study was to determine whether gas pipelines had a significant likelihood of failure from manufacturing defects enlarged by cyclic fatigue, and to identify the range of operating conditions and the periods of time over which this concern could develop.[372] Dr. Kiefner examined the fatigue lives of natural gas pipelines assumed to have worst-case defects (those that would just barely survive a hydro test) and determined that the pipelines had estimated fatigue lives of between 170 to more than 400 years.[373] The conclusion of this 2004 paper was that a natural gas pipeline that experienced a pre-service hydrostatic test to at least 1.39 times the maximum operating pressure of the pipeline would not be expected to experience failure from cyclic fatigue over the course of its useful life.[374]

In 2007, the Department of Transportation (DOT), in collaboration with the Interstate Natural Gas Association of America (INGAA), published another paper authored by Dr. Kiefner that further studied cyclic fatigue on natural gas transmission pipelines and provided guidelines for managing the potential threat.[375] This paper presented Dr. Kiefner's findings on the expected number of years required to bring strength-tested natural gas pipe to failure from cyclic fatigue.[376] The 2007 findings supported those of Dr. Kiefner's 2004 paper – pipe subjected to pre-service strength tests would not be expected to fail from cyclic fatigue within the useful life of the pipeline.[377]

The consensus view that cyclic fatigue did not pose an appreciable risk to natural gas pipelines was reinforced in 2009 by PHMSA in a letter to the National Transportation Safety Board.[378] At the NTSB's request, PHMSA conducted an analysis of natural gas pipelines to determine the significance of the threat posed by cyclic fatigue and manufacturing threats in

[371] Ex. PG&E-7 (Tab 4-23) (Kiefner, John F. and Rosenfeld, Michael J., *Effects of Pressure Cycles on Gas Pipelines*, Sept. 14, 2004).
[372] Ex. PG&E-1 at 6-4 (PG&E/Kiefner).
[373] Ex. PG&E-1 at 6-4 (PG&E/Kiefner).
[374] Ex. PG&E-1 at 6-4 (PG&E/Kiefner).
[375] Ex. PG&E-7 (Tab 4-21) (Kiefner, John F., *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*, Final Report No. 05-12R (Apr. 26, 2007)).
[376] Ex. PG&E-1 at 6-4 (PG&E/Kiefner).
[377] Ex. PG&E-1 at 6-5 (PG&E/Kiefner) (excerpt of comparisons of time to failure from pressure-cycle-induced-fatigue for various proof test levels).
[378] Ex. PG&E-3 (August 10, 2009 PHMSA Letter to NTSB re Safety Recommendation P-04-01).

historic pipelines built with pipe that was not confirmed to have been transported in accordance with an API recommended practice.[379] As stated in the letter to the NTSB:

> PHMSA's research and experience indicates natural gas pipelines are not at significant risk of failure from the pressure-cycle-induced growth of original manufacturing-related or transportation-related defects.[380]

PHMSA's letter cited Dr. Kiefner's 2004 paper in support of its conclusion, stating that "hydrostatic testing of natural gas pipe to a minimum 1.25 times the MAOP is adequate to screen for defects which might lead to pressure-cycle-induced fatigue crack growth to failure, within a pipe's expected lifetime.[381]

The research conducted by Dr. Kiefner, DOT, INGAA and PHMSA shaped and reflected the industry's perspective on cyclic fatigue prior to the San Bruno incident. In Dr. Kiefner's own words in this proceeding:

> I think the significance of the study done in 2007 was to use that information and do some analysis to prove the point that in a natural gas pipeline, this ***cyclic fatigue is simply not a threat that raises its head***.[382]

As the evidence proves, CPSD's position regarding PG&E's treatment of the threat from cyclic fatigue is based on CPSD's post -accident perspective, hindsight information, and its total disregard of the pre-accident consensus that cyclic fatigue was not, in fact, a threat.

b. Informed Reliance On DOT Sponsored Research Constitutes A Legally Adequate Evaluation Of Cyclic Fatigue

CPSD finds no support in the regulations for its assertion that the integrity management regulations required operators to conduct a segment-by-segment fatigue calculation in order to properly evaluate the threat posed by cyclic fatigue. [383] Integrity management regulations direct operators to " **evaluate** **<u>whether</u>** cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a

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[379] Ex. PG&E-3.

[380] Ex. PG&E-3 at 1.

[381] Ex. PG&E-3 at 5.

[382] R.T. 716-17 (PG&E/Kiefner) (emphasis added).

[383] Ex. CPSD-1 at 50-51 (CPSD/Stepanian).

dent or gouge, or other defect in the covered segment." [384] The testimony of Dr. Kiefner, the unquestioned industry expert on cyclic fatigue, establishes that prior to San Bruno many natural gas operators evaluated the threat of cyclic fatigue (and concluded that it did not pose a significant threat to their pipelines) by referencing the prior industry research rather than conducting a detailed assessment of their own pipelines.[385] Dr. Kiefner explained:

> Well, the evaluation itself could be that we have this record that shows that our pipe has been tested, and that's our evaluation. We know that with that test pressure and our cycles that the life is simply not, you know, much longer than the timeframe that we're considering for operating the pipeline. And the 2007 report has several calculations that show that as well as a paper we prepared in 2004 which shows pretty much the same thing, that with typical gas pipeline operating pressures there just simply is not any near term significant threat from cyclic fatigue. And I'll reiterate the fact that you cannot go, other than the San Bruno incident, at least in my observation, to the reportable incident database and find a single example where a natural gas pipeline failed from pressure cycle-induced fatigue.[386]

By contrast, CPSD has introduced no evidence that supports its contention that the code "evaluation" requires a segment-by-segment analysis of an operator's entire pipeline system.[387]

Dr. Kiefner also testified regarding the baseline an operator uses for the evaluation of fatigue.[388] As Dr. Kiefner explained, this baseline can take several forms, one of which is the knowledge that pipe was procured pursuant to an API manufacturing specification, which requires a mill test of specific magnitude. Dr. Kiefner expanded:

> Another way is to look at the one benchmark that almost every pipeline has, and that is a mill pressure test. And with that benchmark, it could easily be shown that you're not at risk. In fact, that's basically what our 2007 work was intended to do for PHMSA was to come up with a kind of criterion where you can – a pipeline operator can say look, we consider our manufacturing defect to be stable in the context of the useful life of our pipeline, and therefore we don't need to address pressure cycle induced

[384] 49 C.F.R. § 192.917(e)(2) (emphasis added).

[385] Ex. PG&E-1 at 6-7 (PG&E/Kiefner).

[386] R.T. 719-20 (PG&E/Kiefner). It is worth noting that the pipe that ruptured in Segment 180 was not properly manufactured DSAW pipe. Properly-made DSAW pipe would not have experienced the cyclic fatigue crack growth identified by Dr. Caligiuri. Ex. PG&E-1 at 3-5 (PG&E/Caligiuri); R.T. 1186-88 (PG&E/Caligiuri).

[387] Ex. CPSD-1 at 50-52 (CPSD/Stepanian).

[388] R.T. 708 (PG&E/Kiefner).

> fatigue…having knowledge that your pipeline is comprised of a material made to a line-pipe specification, an API 5L for example, guarantees that you had a mill hydrostatic test…I could easily look up the mill test pressure applied to that pipe, the standard minimum mill test pressure in order for the manufacturer to validly stamp that pipe.[389]

In the words of Dr. Kiefner, as applied to pipe subjected to an API-required mill test, the calculations in Dr. Kiefner's 2004 and 2007 studies "invariably results in a very long time to failure [and therefore] we really don't think [cyclic fatigue is] an issue."[390]

c. PG&E Appropriately Evaluated The Threat Of Cyclic Fatigue

In the early years of its Integrity Management program, PG&E evaluated the threat of cyclic fatigue on its pipelines through a combination of the means described by Dr. Kiefner in his testimony.[391] PG&E witness Kris Keas explained:

> [W]hat PG&E used was they did some initial calculations on one of their pipelines to see if they thought that a wors[t] case scenario would be potentially affected by cyclic fatigue. They did not find that to be so.
>
> And then they did an evaluation of the industry literature regarding the potential for cyclic fatigue to occur on natural gas pipelines. And if you look at the literature, the literature says that cyclic fatigue is really not an issue on … natural gas pipelines. So based upon that information we – we decided that we did not think that cyclic fatigue was an active threat on our pipelines.[392]

The record shows that, in its audit protocol matrices, PG&E explicitly informed PHMSA and the CPUC how PG&E had evaluated the threat of cyclic fatigue on its pipelines, and PG&E's conclusion there was no significant threat. Audit protocol matrices are PG&E -created documents assembled prior to regulatory audits that identify particular sections of Risk Management Procedures that are the subject of the PHMSA audit protocol.[393] In essence, PG&E's audit protocol matrix serves as a roadmap for the auditors to evaluate PG&E's Integrity

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[389] R.T. 711-13 (PG&E/Kiefner).

[390] R.T. 737 (PG&E/Kiefner).

[391] Joint R.T. 1000-02 (PG&E/Keas).

[392] Joint R.T. 1001 (PG&E/Keas). PG&E's analysis included a review of the work don by Dr. Kiefner.

[393] Ex. PG&E-1c at 4-30, n.18 (PG&E/Keas).

Management program.[394] PG&E provided PHMSA and the CPUC with the audit protocol matrices, in 2005 and 2010, which stated in writing PG&E's assessment of cyclic fatigue and its conclusion regarding the absence of the threat.[395] As documented in its audit protocol matrices, PG&E concluded cyclic fatigue was "not considered a threat due to the level of increases and the frequency of pressure increases in our system."[396] PG&E also described that it was participating in INGAA research to review the 2004 Kiefner report, as well as reviewing pipelines in its system with the greatest potential for cyclic fatigue to verify its evaluation and conclusion.[397]

In integrity management audits in 2005 and 2010, CPSD and PHMSA found PG&E's threat identification process satisfactory. In both 2005 and 2010, the audit followed PHMSA's audit protocol.[398] During both audits, inspectors reviewed PG&E's policies and procedures for, among other required integrity management program elements, the threat identification process.[399] Section C.01 of PHMSA's audit protocol, titled "Threat Identification" directs the inspector to "verify that the operator identifies and evaluates all potential threats to each covered pipeline segment."[400] Section C.01.c directs the inspector to "verify that the operator's threat identification has considered interactive threats from different categories, examples, manufacturing defects activated by pressure cycling, corrosion accelerated by third party, or outside force damage."[401] In both sections of both audit results, PHMSA and the CPUC identified no issues relating to PG&E's identification and evaluation of cyclic fatigue.[402] Despite two prior reviews of PG&E's threat identification process, CPSD alleged violations of the

[394] Ex. PG&E-1c at 4-30, n.18 (PG&E/Keas).

[395] Ex. PG&E-1c at 4-30 to 4-31 (PG&E/Keas).

[396] Ex. PG&E-7 (Tab 4-24) at 12 (2005 Audit Protocol Matrix). The full entry states: "Based on preliminary assessment, [cyclic fatigue is] not considered a threat due to the level of increase and frequency of pressure increases in our system. However, also participating with INGAA in review of Kiefner Cyclic Fatigue report to determine if there are situations that would be a concern. Also performing some review of pipelines with the greatest potential for cyclic fatigue to verify our preliminary assessment (*see* RMP-6 section 4.3)."

[397] Ex. PG&E-7 (Tab 4-24) at 12 (2005 Audit Protocol Matrix).

[398] *See* Ex. PG&E-7 (Tab 4-25) (2005 Audit Inspection Protocols with Results Forms); Ex. PG&E-7 (Tab 4-13) (2010 Audit Inspection Protocols with Results Forms).

[399] Joint R.T. 1192-96 (PG&E/Keas).

[400] *See, e.g.*, Ex. PG&E-7 (Tab 4-25) (2005 Audit Inspection Protocols with Results Forms).

[401] *See, e.g.*, Ex. PG&E-7 (Tab 4-25) (2005 Audit Inspection Protocols with Results Forms).

[402] Joint R.T. 1192-96 (PG&E/Keas); Ex. PG&E-7 (Tab 4-25) (2005 Audit Inspection Protocols with Results Forms); Ex. PG&E-7 (Tab 4-13) (2010 Audit Inspection Protocols with Results Forms).

integrity management regulations in PG&E's evaluation of cyclic fatigue for the first time in CPSD's January 12, 2012 Report.[403]

d. Application Of Dr. Kiefner's Analysis Shows Segment 180 Would Not Be Expected To Experience Cyclic Fatigue During Its Useful Life

CPSD alleges that had PG&E conducted a cyclic fatigue analysis of pipeline segments for which it did not have a documented hydro test, PG&E would have determined that portions of Line 132 (including Segment 180) were subject to an unstable manufacturing threat.[404] CPSD's conclusions are erroneous.

The pipe for Line 132 and the construction of Segment 180 was procured pursuant to a specification calling for the pipe to be subject to a mill hydro test to 90% of the pipeline SMYS.[405] Such a mill test, while of short duration, is considered in Dr. Kiefner's 2007 study as sufficient to ensure that any remaining manufacturing defects would be too small to fail at the maximum operating pressure.[406] When subjected to Dr. Kiefner's analysis, Segment 180 (as reflected in PG&E's procurement records) would not be expected to experience fatigue-induced failure during its useful life. In Dr. Kiefner's words:

> [T]he pipeline, thinking of the primary pipe, was 3[0]-inch diameter, 3/8s inch wall thickness, grade X-52 double submerged arc welded pipe. And on the basis of that, there was no reason to suspect fatigue.[407]
>
> [. . .]
>
> The test pressure to operating pressure ratio [for the pipe procured for Line 132, Segment 180] was more than two to one. It demonstrated that it would take literally hundreds of years for any

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[403] CPSD's allegations are reiterated in audit findings from a joint CPSD-PHMSA audit of PG&E's Integrity Management program conducted after the San Bruno incident. CPSD provided the findings to PG&E on August 31, 2012, two months after PG&E served its prepared testimony in this proceeding. PG&E responded to CPSD's latest audit on October 17, 2012. Ex. Joint-3 9 (PG&E's Response to GO-112E Audit of PG&E's Integrity Management Program).

[404] Ex. CPSD-1 at 51-53 (CPSD/Stepanian).

[405] Ex. PG&E-1 at 2-2 to 2-3 (PG&E/Harrison); Ex. PG&E-7 (Tab 4-20) (pipe specifications for 1948 construction of Line 132). *See infra*, Section V.B.3.a.iii.

[406] Ex. PG&E-1 at 6-5 (PG&E/Kiefner).

[407] R.T. 691-92 (PG&E/Kiefner).

> defect that survived that test to grow to failure under the operating pressure spectrum that we used in our analysis.[408]

3. PG&E's Threat Identification Process Satisfied Regulatory Requirements

CPSD alleges violations relating to PG&E's threat identification process. CPSD alleges that (a) PG&E violated 49 C.F.R. Section 192.917(b) by failing to consider data relating to longitudinal seam defects in its assessment of potential manufacturing defects on Line 132;[409] and (b) PG&E failed to identify an unstable manufacturing threat on Segment 181 "or other similar segments", in purported violation of Section 192.917(e)(3).[410] CPSD's allegations have no support in the regulations or the evidentiary record.

a. CPSD's Allegations Regarding The Significance Of Leak Records Find No Support In The Law Or The Record

CPSD alleges that PG&E violated the law by purportedly failing to consider data relating to longitudinal seam leaks for the purpose of identifying manufacturing threats on Line 132. CPSD alleges that PG&E should have determined that Line 132 was subject to a potential manufacturing threat based on consideration of records of longitudinal seam cracks dating to the 1948 construction of the pipeline, records of a 1988 leak on the long seam of a portion of Line 132 and other assorted records identified in the NTSB Report.[411] As discussed bel ow, CPSD's allegations are unsupported and without merit.

(i) The Evidence Demonstrated That Leak Records Are Of Only Marginal Value To Identification Of Manufacturing Defects

Under ASME B31.8S, Appendix A, section 4.2, gas transmission pipeline operators are not required to review leak records for purposes of determining the potential for a manufacturing

[408] R.T. 836 (PG&E/Kiefner). Before September 9, 2010, cyclic fatigue analysis would not have taken into consideration the defective pups; their presence in Segment 180 was not known until after the accident. CPSD's assertion that PG&E should have suspected cyclic fatigue in the DSAW pipe procured for Segment 180 is contrary to expert and industry consensus.

[409] Ex. CPSD-1 at 30, 163 (CPSD/Stepanian). CPSD's report categorizes this as a data gathering and integration issue. PG&E addresses the significance of leak data as it relates to threat identification in this section.

[410] Ex. CPSD-1 at 46-47, 163 (CPSD/Stepanian).

[411] Ex. CPSD-1 at 46-47, 163 (CPSD/Stepanian).

threat.[412] Leak data is relevant to (and is a data element specified in ASME B31.8S, Appendix A for) time-dependent threats such as internal and external corrosion. [413] Leak records are only tangentially-related to the manufacturing threat identification process, as any leak that is significant enough to merit such analysis would result in a reportable pipeline incident. [414] While PG&E did gather leak data as part of the pre-assessment process for Line 132, [415] CPSD's assertion that the failure to identify a particular leak record constitutes a violation of ASME B31.8S is contrary to the ASME data gathering provisions.

(ii) The Evidence Shows That The 1988 Leak Does Not Indicate A Manufacturing Threat On Line 132

Contrary to CPSD's assertions, records from the 1988 leak on Line 132 would not have led PG&E to consider other segments on Line 132 as subject to an unstable manufacturing threat. Metallurgical investigation of the pipe involved showed the 1988 leak was a very small (pinhole) leak attributed to the longitudinal seam of 30-inch DSAW pipe, the type of leak which does not constitute a structural integrity concern.[416] During microscopic examination, PG&E's Technical and Ecological Services (TES) group could not even locate the leak in the weld.[417]

CPSD focuses on the following language in the TES report on its examination of the pipe seam:

> The X-ray and subsequent metallographic examination identified several weld shrinkage cracks, but they did not extend through wall. The cracks are pre-service defects, i.e., they are from the original manufacturing of the pipe joint.
>
> Overall 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.[418]

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[412] Records R.T. 1492-95 (PG&E/Keas) (admitted into San Bruno OII– *see* Joint R.T. 623-25); Ex. Joint-28 (AMSE B31.8S), Appendix A, § 4.2 (2004).

[413] Records R.T. 1492-95 (PG&E/Keas).

[414] Records R.T. 1492-95 (PG&E/Keas).

[415] Ex. PG&E-1c at 4-14 (PG&E/Keas).

[416] Ex. PG&E-1c at 4-14 to 4-15 (PG&E/Keas); Ex. PG&E-7 (Tab 4-16) (Technical and Ecological Services Letter re Bunker Hill 30" Transmission Line Failure ("With the leak removed, the remaining pipe should be fully operational again.")).

[417] Ex. PG&E-7 (Tab 4-16).

[418] Ex. PG&E-7 (Tab 4-16).

CPSD ignores the bottom-line conclusion of the TES examination:

> With the leak removed, the remaining pipe should be fully operational again.[419]

The evidence supports the TES conclusion. As John Zurcher testified, even DSAW, considered one of the best performing types of pipe (and given a joint efficiency rating of 1.0 in the regulations and ASME B31.8S), may exhibit manufacturing imperfections and experience these small, pinhole-type leaks from time to time.[420] Leaks of this type do not signal the presence of unstable manufacturing defects as they have not been found to lead to pipeline ruptures and are thus not relevant to the determination of a long seam manufacturing threat.[421]

[redacted]

> [redacted]

> [redacted]

> [redacted]

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[419] Ex. PG&E-7 (Tab 4-16).

[420] Ex. PG&E-1 at 5-10 to 5-11 (PG&E/Zurcher); Joint R.T. 870-71 (PG&E/Zurcher).

[421] Joint R.T. 871 (PG&E/Zurcher). Such leaks may, however, result in reportable pipeline incidents due to the cost of excavation and repair. *Id.*

[redacted]

As had Mr. Zurcher, [redacted]

> [redacted]
>
> [redacted]

CPSD's focus on the 1988 pinhole leak is misplaced, and does not prove the violation it alleges.

(iii) Even in Hindsight, The 1948 Construction Records Do Not Indicate A Manufacturing Threat On Line 132

CPSD claims that, having noted indications of long seam imperfections through radiography during the 1948 Line 132 construction, PG&E should thereafter have identified Line 132 (or at least the portions constructed with 30-inch DSAW pipe manufactured by Consolidated Western and installed in 1948) as subject to an unstable manufacturing threat. [425] However, as the evidence demonstrated, the long seam imperfections identified during the 1948 radiography do not constitute unstable manufacturing threats.

The pipe procurement records for the 1948 Line 132 construction, [426] as well as a Moody Engineering mill inspection report from PG&E's 1949 purchase of pipe identical to the Line 132 pipe,[427] establish that PG &E's pipe specifications called for the pipe to be subjected to a 90% SMYS hydro test at the mill.[428] A mill test to 90% SMYS is 1.25 times the MAOP of this pipe if it were operating in a Class 1 location at 72% SMYS, and equates to a much higher ratio given

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[redacted]

[425] Ex. CPSD-1 at 46 (CPSD/Stepanian).

[426] Ex. PG&E-7 (Tab 4-20) (PG&E Pipe Specifications, Line 132 (1948)).

[427] PG&E contracted Moody Engineering Company to inspect the manufacturing process and testing of the Line 132 pipe at Consolidated Western's plant. Ex. PG&E-7 (Tab 4-17) (Moody Engineering Invoice – 1948). PG&E has not located the final Moody report issued in connection with this inspection, but has located the Moody Engineering Inspection Report for pipe ordered three months later from Consolidated Western, the specifications for which were identical to the Line 132 pipe specifications. Ex. PG&E-7 (Tab 4-18) (Moody Engineering Pipe Inspection Report (1949). Given that the orders were contemporaneous and that both were for the same pipe specification filled by the same manufacturer (and at the same mill inspected by the same engineering company), it is reasonable to conclude that the manufacturing and inspection processes were identical for both pipe purchases.

[428] Ex. PG&E-7 (Tab 4-20); Ex. PG&E-7 (Tab 4-18).

that the Line 132 MAOP of 400 psig was well below 72% SMYS.[429] For Line 132, the pipe specifications called for the 90% SMYS mill test, at a resulting test pressure of 1170 psig.[430] 1170 psig is nearly three times the 400 psig MAOP of Line 132. By design, any defects that do not fail during this mill test are assumed to be safe and stable at the established operating pressure.[431] The 1948 construction radiography records therefore do not (and did not) indicate the presence of an unstable manufacturing threat.

(iv) The Miscellaneous Long Seam Issues Identified By CPSD Would Not Inform A Manufacturing Threat Assessment Of Line 132

CPSD also alleges that PG&E should have considered in its assessment of manufacturing threats on Line 132 an assortment of longitudinal seam issues identified in Table 2 of the NTSB's Report.[432] However, most of the listed records involve pipe dissimilar to the 30-inch DSAW pipe used in Line 132 and thus they would not meaningfully inform integrity assessment of that pipeline.[433] CPSD's reli ance on the remaining records is similarly misplaced. The reference to a long-seam defect on a segment of Line 132 in 1992 is based on a misinterpretation of statements made by a PG&E employee during an NTSB interview.[434] The remaining items identified in Table 2 were discovered during testing carried out after the San Bruno accident. CPSD cannot legitimately allege a violation of law for PG&E's failure to consider in its pre-accident integrity assessments information learned only after the accident itself. Taken together, the miscellaneous long seam issues identified by CPSD only reinforce the fact that before September 9, 2010, PG&E had not experienced long seam failures on 30-inch DSAW pipe similar to that used to construct Segment 180, and had no reason to consider any segment constructed with this pipe as subject to a potentially unstable long seam manufacturing threat.

[429] *See generally* Ex. PG&E-1 at 6-6 (PG&E/Kiefner).

[430] Ex. PG&E-7 (Tab 4-19) (Line 132 procurement specifications).

[431] Ex. PG&E-1 at 6-5 (PG&E/Kiefner); R.T. 691-92, 770, 786-87, 832 (PG&E/Kiefner).

[432] Ex. CPSD-1 at 32-33 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report), Table 2.

[433] Joint R.T. 1087 (PG&E/Keas).

[434] Ex. PG&E-7 (Tab 4-22) at 6-30 (NTSB Telephone Interview of Joe Joaquim). The company employee could not recall the pipeline on which the defect he described was located, thus the conclusion that it was on Line 132 is not supported by his statements.

b. CPSD Did Not Prove The Regulations Required PG&E To Assess Segment 181 For A Long-Seam Manufacturing Threat

CPSD places great importance on its analysis of a purported long seam manufacturing threat on Segment 181 of Line 132. [435] In CPSD's view, Segment 181 is the key to its argument that PG&E should have hydro tested Segment 180, and had it done so, would have prevented this accident. CPSD's theory starts and ends with untenable speculation, and actual evidence destroys it completely. CPSD's theory, stated as briefly as it can be, is:

- PG&E conducted a planned pressure increase on Line 132 on December 11, 2003;
- Prior to that, PG&E identified Segment 181 as an HCA, as defined in federal integrity management regulations that did not become effective until two months after the planned pressure increase;
- The planned pressure increase slightly exceeded the MAOP of Line 132 at Milpitas Terminal (40 miles south of Segment 181);
- Due to the pressure exceeding MAOP at Milpitas Terminal, PG&E should have treated an identified manufacturing threat on Segment 181 as an unstable seam threat, even though the identified threat on Segment 181 was to the pipe body, not the seam;
- Because of the purportedly unstable seam threat, PG&E should have assessed Segment 181 with a method capable of detecting seam defects, such as hydro testing;
- Had PG&E hydro tested Segment 181, it might have cut into the adjacent Segment 180 as part of the physical setup for the hydro test;
- If PG&E cut into Segment 180, it might have noticed that the Segment 180 pipe was DSAW, not seamless as recorded in GIS;
- Rather than simply correcting GIS to reflect the pipe was DSAW, as research of the paper records would have shown, PG&E might have hydro tested Segment 180;
- If PG&E had hydro tested Segment 180, it would have discovered the seam defect in the pup, and thereby have prevented the accident. [436]

[435] Ex. CPSD-1 at 42-49 (CPSD/Stepanian).

[436] Ex. CPSD-1 at 42-49 (CPSD/Stepanian).

To state CPSD's theory is to refute it. Add the evidentiary record, and CPSD's theory is shown to be completely erroneous and based on a misconstruction and misunderstanding of ASME B31.8S and the applicable federal regulations.

(i) CPSD Failed To Prove Segment 181 Was Subject To A Potential Long-Seam Manufacturing Threat

Not all manufacturing and construction threats are related to the long seam of the pipe. Threats that are not related to the long seam do not require the operator to conduct a seam assessment.[437] PG&E's GIS records used in the manufacturing threat identification process accurately reflect job file documents demonstrating that Segment 181 was constructed in 1948 from 30-inch DSAW pipe manufactured by Consolidated Western.[438] Prior to the San Bruno accident, this type of pipe did not have a history of in-service pipeline failure, either in PG&E or industry experience, and was assigned a joint efficiency of 1.0 under both the federal integrity management regulations and PG&E's Integrity Management program.[439] Contrary to CPSD's assertion, and as established by the uncontradicted testimony of experts Zurcher, Kiefner and Caligiuri, prior to the San Bruno accident there was no reason for PG&E (or any operator) to conclude that DSAW pipe contained a potential manufacturing seam threat under the integrity management rules.[440]

As PG&E witness Kris Keas explained, Segment 181 was identified in 2004 as subject to a potential manufacturing threat solely because the pipe in Segment 181 was over 50 years old, not because a suspected or known manufacturing seam threat existed.[441] Per ASME B31.8S Appendix A, section 4.3, pipe greater than 50 years old is grouped with mechanically coupled pipelines and pipelines constructed with oxyacetylene girth welds as at-risk of failure if exposed to low temperatures or if located in an area of ground movement (these are examples of non-long seam related manufacturing threats).[442] If exposed to such conditions, ASME B31.8S requires an

[437] Ex. PG&E-1c at 4-15 (PG&E/Keas).

[438] Ex. PG&E-1c at 4-15 (PG&E/Keas).

[439] Ex. PG&E-1c at 4-15 to 4-16 (PG&E/Keas). The pipe that ruptured was not properly-manufactured DSAW pipe. Ex. PG&E-1 at 3-5 to 3-17 (PG&E/Caligiuri).

[440] Joint R.T. 967 (PG&E/Keas) ("Based upon the criteria provided by code, DSAW pipe isn't considered [to be subject to] a manufacturing threat."); Ex. PG&E -1 at 3-5 (PG&E/Caligiuri); Ex. PG&E-1 at 5-9 (PG&E/Zurcher); Ex. PG&E-1 at 6-5 to 6-6 (PG&E/Kiefner); R.T. 691-92 (PG&E/Kiefner).

[441] Ex. PG&E-1c at 4-16 (PG&E/Keas).

[442] Ex. Joint 28 (ASME B31.8S-2004), Appendix A, § 4.3.

operator to initiate a pipeline movement-monitoring program, and to take appropriate intervention (e.g., relocation, replacement). Neither the age of the pipe, nor the presence of substandard girth welds, constitutes a manufacturing threat related to the long seam.[443] PG&E has implemented a ground movement monitoring program to mitigate such threats, including monitoring rainfall to identify potential landslides, reviewing and relocating pipelines in earthquake fault crossings, and avoiding construction-related damage that may include removal of support for a pipeline.[444]

Despite the universal expert and industry consensus to the contrary, CPSD asserts that PG&E should have considered all DSAW pipe (including Segment 181) as subject to a long seam manufacturing threat based on information from *Integrity Characteristics of Vintage Pipelines*, a report prepared by Battelle Memorial Institute for the INGAA Foundation.[445] However, as reflected in the report, both SSAW and DSAW pipe welds are not prone to anomalies such as long seam cracks. While there have been isolated occurrences of anomalies, these are rare and occurred mostly in pre-1960 pipe manufactured by Kaiser or U.S. Steel.[446] Consistent with the information in the INGAA report, PG&E's Integrity Management program would not have considered pipe manufactured by PG&E's principal large pipe supplier of the time, Consolidated Western, as subject to a manufacturing threat. Additionally, the pipeline incidents identified on DSAW (and on all other seam types) in the *Integrity Characteristics of Vintage Pipelines* report are only presented as summary data, without providing additional information on the incident that would make it relevant to a manufacturing threat identification process.[447] For example, to make the incident tables usable, an operator would need to know what kind of service the pipelines were in, to what specification the pipes were ordered, and how the pipelines were installed to identify the incidents that would have significance to the operator's system.[448] Even applying hindsight, as CPSD does, this report does not support

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[443] Ex. Joint-28 (ASME B31.8S-2004), Appendix A § 4.3.
[444] Joint R.T. 1142-51 (PG&E/Keas).
[445] Ex. CPSD-1 at 41, 46 (CPSD/Stepanian).
[446] Ex. Joint-49 (*Integrity Characteristics of Vintage Pipelines*) Table E-9, at E-11.
[447] Joint R.T. 973 (PG&E/Keas).
[448] Joint R.T. 973 (PG&E/Keas).

CPSD's assertion that PG&E should have identified the DSAW pipe in Segment 181 as subject to a long seam manufacturing threat.[449] *See supra*, Section IV.A.2.

(ii) Even If Segment 181 Were Subject To A Long-Seam Manufacturing Threat, The Threat Would Be Stable And Not Require Assessment

Assuming, for the sake of argument, that Segment 181 was subject to a manufacturing seam threat, CPSD's assertion that PG&E was required by law to conduct an integrity assessment on Segment 181 (and in turn, Segment 180) remains erroneous. Absent an increase in operating pressure of the type described in Section 192.917(e)(3), a stable manufacturing seam threat is not rendered unstable, and no seam assessment is required for a stable manufacturing threat.[450] CPSD claims that planned pressure increases PG&E carried out rendered the purported manufacturing threat on Segment 181 unstable under 49 C.F.R. § 192.917(e)(3). [451] Contrary to CPSD's claim, PG&E's December 2003 pressure exercise predated the identification of HCAs (December 2004) and the effective date of the integrity management regulations (February 2004), and therefore could not have triggered the regulatory requirements on which CPSD relies.[452] PG&E's 2008 pressure increase on Line 132 did not significantly exceed the pipeline MAOP, and was only a transient excursion that did not constitute an "operating pressure increase" under 49 C.F.R. § 192.917(e). [453] Therefore, even assuming the DSAW pipe in Segment 181 had the long seam manufacturing threat (it did not), neither the 2003 nor the 2008 pressure exercise rendered it unstable so as to require a priority integrity assessment of the longitudinal seam.

(a) The 2003 Pressure Increase Predated Identification Of PG&E's High Consequence Areas

Section 192.917(e)(3) requires an operator to prioritize for assessment, using a tool capable of identifying seam defects, any pipeline segment that (1) has a manufacturing seam

[449] Ex. PG&E-1 at 5-9 to 5-12 (PG&E/Zurcher).

[450] *See, e.g.*, 49 C.F.R. § 192.917(e)(3); Ex. Joint-28 (ASME B31.8S-2004) Appendix A, § 4.3.

[451] Ex. CPSD-1 at 42-49 (CPSD/Stepanian).

[452] Even putting aside that the regulations CPSD points to were not in effect in December 2003, the pressure on Line 132 at Milpitas Terminal during the planned increase was only a transient excursion over MAOP.

[453] Discussed in detail below.

threat, and (2) has been subject to an "operating pressure increase" above the operating pressure experienced in the five years preceding the date the segment was identified as an HCA segment.[454] PHMSA published this code section on December 17, 2003, when it promulgated the final integrity management rule (Subpart O), which was effective February 14, 2004.[455] The Subpart O rules required operators to develop a written integrity management plan by December 17, 2004.[456] The written integrity management plan had to include identification of all HCAs.[457]

PG&E operated Line 132 to approximately 400 psig on December 11, 2003 - prior to issuance of the final rule. At that time, PG&E had not and – because the definition of an HCA had not been finalized or codified in the integrity management regulations – could not have identified any pipeline segment as being within an HCA.[458] PG&E filed its HCA identification in its Baseline Assessment Plan (BAP) in December 2004, the time at which the regulations required operators to identify HCAs, and a year after the December 2003 pressure increase on Line 132.[459] PG&E's approach was consistent with 49 C.F.R. § 192.907(a), which required operators to identify all HCA pipe no later than December 17, 2004. Because PG&E conducted the pressure increase on Line 132 prior to filing its BAP, prior to issuance of the final rule defining HCAs, and prior to publication of the integrity assessment requirement in 192.917(e)(3), PG&E's planned pressure increase on Line 132 in 2003 could not and did not trigger the requirement to prioritize any segment on Line 132, including Segment 181, for long seam assessment under 49 C.F.R. § 192.917(e)(3).[460]

(b) PG&E's Planned Pressure Increase In 2008 Did Not Trigger A Long-Seam Assessment

The maximum pressure on Line 132 in 2008 was measured at 400.73 psig at Milpitas Terminal (approximately 39 miles from the Segment 180 rupture); the pressure at Half Moon

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[454] 49 C.F.R. § 192.917(e)(3) (also addressing uprated pipe and increased potential for cyclic fatigue).

[455] 68 Fed. Reg. 69,778; 69 Fed. Reg. 2307.

[456] 49 C.F.R. § 192.907(a).

[457] 49 C.F.R. § 192.911(a).

[458] Similarly, 49 C.F.R. § 192.917(e)(3) had not been finalized as of December 11, 2003. Thus, even if PG&E had identified HCA pipelines, the assessment mandates under Section 192.917(e)(3) were not in effect on December 11, 2003, when the company raised pressure on Line 132.

[459] Ex. PG&E-1c at 4-24 (PG&E/Keas).

[460] The integrity management regulations did not become effective until February 2004. 69 Fed. Reg. 2,307 (Jan. 4, 2004). Thus, in December 2003, Section 192.917(e)(3) had no legal effect and could not, as a matter of law, be violated.

Bay and Martin Station, the two closest monitoring points up and downstream from the rupture, only reached 382 psig. [461] This pressure excursion at Milpitas Terminal did not constitute an operating pressure increase that would require the pipeline to be prioritized for assessment. As explained in the preamble to the integrity management regulations, 49 C.F.R. 192.917(e)(3) was intended to address **changed operating conditions**, not transient excursions like that on Line 132 in 2008:

> Changes in operating conditions, such a significant increase in pressure, could cause latent defects to grow. Therefore, if the pipeline operating conditions change such that operating pressure will be above historic operating pressure, if MAOP increases, or if the stresses that could lead to cyclic fatigue increase, the operator must treat the covered segment as a high-risk segment.[462]

Mr. Zurcher, who helped write the integrity management regulations, explained it clearly:

> Q: So if you exceed the MAOP – and my question when I asked you if you exceed the MAOP, that means you would exceed the historic operating level; is that correct?
>
> A: Well, again, I think we continue to have a terminology issue here. The regulations and the standard address raising the operating pressure, not just having a pressure exceedance. It's – the operating pressure is a number. Every company has one. It's a normal operating pressure, that is when that integrity threat may kick in for certain seam types. But the fact that you had an excursion above the operating pressure or above MAOP does not kick in the need for an assessment for the manufacturing threat.[463]

Before and after the 2008 planned pressure increase, the MAOP on Line 132 remained unchanged at 400 psig, as did the normal operating pressure, which are the types of changed conditions Section 192.917(e)(3) addresses. 49 C.F.R. § 192.917(e)(3) (requiring priority assessment where "[o]perating pressure increases above the maximum operating pressure experienced during the preceding five years[.]").

Even assuming a transient pressure excursion was relevant under 49 C.F.R. 192.917(e)(3), the 2008 pressure increase would not have triggered a priority assessment. As explained in Dr. Kiefner's 2007 DOT Report (at pages 17-21), an increase of such a small

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[461] Ex. CPSD-31; Ex. CPSD-9 (NTSB Report) at 91, n.131.

[462] 68 Fed. Reg. 69,804.

[463] Joint R.T. 749-50 (PG&E/Zurcher).

magnitude (less than 1 pound over MAOP on pipeline that has been mill tested to at least 1.25 times the pipeline MAOP) does not have the capability of rendering stable manufacturing threats on a long seam unstable. [464] Dr. Kiefner's conc lusion is consistent with PHMSA Frequently Asked Question (FAQ) 221, which, when read in conjunction with FAQ 220, addresses changes in operating conditions – no matter how small – that require prioritization of the segment for assessment.[465] As shown above, the changes in operating conditions contemplated under the integrity management regulations are "operating pressure increases," not short duration excursions like the 2008 planned pressure increase on Line 132.

4. CPSD's Allegations Regarding The Assessme nt Tool For Segment 180 Are Based On Hindsight

CPSD's claim that PG&E violated the integrity management rules in its selection of the assessment tool for Segment 180 [466] is based on hindsight rather than information available to PG&E prior to the San Bruno accident. As described in detail, *supra,* the evidence established that PG&E's Integrity Management program gathered the proper data and conducted threat identification for Line 132, Segment 180 consistent with ASME B31.8S and the federal integrity management regulations. Through the data gathering and threat identification process, PG&E identified external corrosion as the primary threat to Segment 180 (and Segment 181), and consistent with the integrity management rules and PG&E's Integrity Management proc edures, concluded that external corrosion direct assessment was the appropriate assessment methodology to use. CPSD does not dispute that the integrity management regulations identify external corrosion direct assessment as an acceptable assessment technique to address the threat of external corrosion.[467]

While PG&E's records erroneously identified Segment 180 as seamless, this had no effect on the integrity management assessment method chosen for the pipeline. Before

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[464] Ex. PG&E-7 (Tab 4-21) at 17-21; R.T. 738-39 (PG&E/Kiefner) ("[E]xceeding the operating pressure constitutes a large cycle…but you could still – if the margin that you have based on that going over your operating pressure is still well below your test pressure, that really doesn't significantly change the fact that the life will be quite long. It may be shortened some, but it is still shortened from a long starting point.").

[465] Joint R.T. 977-78 (Keas/PG&E). PHMSA FAQ 221 states that any pressure increase, regardless of amount, requires that the segment be prioritized as high risk for integrity assessment. PHMSA FAQ 220 states that assessment for manufacturing defects generally are not required for pipe that has been subjected to a pre-service hydro test, even if changes in operating conditions occur.

[466] Ex. CPSD-1 at 59-61 (CPSD/Stepanian).

[467] 49 C.F.R. § 192.923.

September 9, 2010, PG&E and the industry as a whole considered DSAW pipe to be equivalent to seamless pipe, as reflected by its joint efficiency factor (1.0) and its absence from the categories of pipe identified in ASME B31.8S as potentially subject to manufacturing threats. [468] Ms. Keas testified:

> And as far as the manufacturing threat, DSAW and – the point that I was trying to make in this testimony is that DSAW and seamless have really good performance in the industry. And that's the reason why they're established as having a joint efficiency factor of one. And both types of seams would not be considered a manufacturing threat.[469]

PG&E would have had no reason to believe that Segment 180 was subject to a potentially unstable manufacturing defect if its GIS had reflected DSAW pipe. PG&E's determination that cyclic fatigue was not a threat to PG&E's pipelines (including Segment 180), which was well supported by industry experience and scientific analysis, also would not have been altered.

In sum, PG&E's Integrity Management program followed regulatory requirements and industry consensus standards in carrying out external corrosion direct assessment on Line 132 and Segment 180. CPSD has introduced no basis – beyond the imputation of information learned only through the post-accident investigation – to assert that PG&E's selection of assessment technique for Segment 180 violated the law.

C. Recordkeeping Violations

Despite having a separate enforcement action regarding PG&E's recordkeeping practices,[470] CPSD alleges again here that PG&E's recordkeeping was inadequate under ASA B31.1.8-1955, thereby violating Public Utilities Code Section 451. [471] Distilled to its essence, CPSD alleges the following: (1) PG&E is missing records regarding the design, construction, and specifications for Segment 180; [472] (2) PG&E's records failed to show the existence of the pups;[473] (3) PG&E's GIS contained erroneous information regarding Segment 180; [474] and

[468] 49 C.F.R. § 192.113; Ex. Joint-28 (ASME B31.8S-2004) Appendix A, § 4.3.
[469] Joint R.T. 992-93, 997-98, 1053-54 (PG&E/Keas).
[470] I.11-02-016 at 9-10.
[471] Ex. CPSD-1 at 3-4, 62-69 (CPSD/Stepanian).
[472] Ex. CPSD-5 at 34 (CPSD/Stepanian); Ex. CPSD-1 at 64-66 (CPSD/Stepanian).
[473] Ex. CPSD-5 at 34 (CPSD/Stepanian); Ex. CPSD-1 at 66 (CPSD/Stepanian).
[474] Ex. CPSD-1 at 64 (CPSD/Stepanian).

(4) PG&E failed to preserve images purportedly recorded by a security camera in the backup gas control room in Brentwood in violation of Commission Resolution No. L-403 and Public Utilities Code 702.[475] Each of CPSD's claims lacks evidentiary and legal support. In any event, the Commission should disregard these allegations because they are duplicative of CPSD's allegations in the Records OII proceeding.

1. Design And Construction Records And Specifications For Segment 180

CPSD asserts PG&E was unable to locate design, construction and material specification records for Segment 180, allegedly in violation of recordkeeping requirements in ASA B31.1.8-1955.[476] CPSD's claim fails, however, because it is relying on a voluntary industry guideline, ASA B31.1.8, as the basis for alleging Section 451 violation. In addition to CPSD's improper expansion of Section 451 (discussed in detail in Section III.B. above), CPSD's allegations in effect circumvent the Commission's determination in General Order 112 in 1961 to partially exempt existing installations from the mandates of GO 112 insofar as design, fabrication, installation, established operating pressure, and testing are concerned.[477] In 1956, there was no legal retention requirement applicable to the records CPSD identifies. The recordkeeping provisions in the voluntary industry guideline, ASA B31.1.8-1955, addressed pressure test records (841.417), operation and maintenance procedures (850.3(c)), welding qualification records (824.25), corrosion records (851.4) and leak records (851.5).[478] Except with respect to pressure records, none of these record categories relate to pipeline installation and construction. CPSD has not identified a legitimate basis for this alleged violation.[479]

Regardless, the evidence demonstrated that PG&E's Segment 180 construction records contain the information CPSD alleges is lacking. As Mr. Harrison testified, the Segment 180 job file contains construction drawings, pipe specifications, and as-built documentation.[480] CPSD presented no evidence to the contrary.

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[475] Ex. CPSD-1 at 67-69 (CPSD/Stepanian).
[476] Ex. CPSD-1 at 62 (CPSD/Stepanian); Ex. CPSD-5 at 34-35 (CPSD/Stepanian).
[477] *Investigation into the Need of a General Order, etc*, Decision No. 61269 (1960) (adopting GO 112) at § 104.3.
[478] PG&E's Request for Official Notice, Ex. 5 (Ex. Records PG&E47 (ASA B31.1.8) (1955)).
[479] *See e.g.,* PG&E-1 at 2-4 to 2-5 (PG&E/Harrison).
[480] Joint R.T. 319-29 (PG&E/Harrison); *see* Ex. Joint-10 and Ex. Joint-12.

In the Records OII, CPSD alleges 14 violations related to Segment 180 records. [redacted] In particular, alleged violations 1 and 2 (Felts) relate to Segment 180 construction records, violation 3 relates to pressure test records for Segment 180, and violation 18 (Felts) relates generally to missing design and pressure test records. [redacted] CPSD's allegations regarding Segment 180 records in this proceeding are duplicative of and subsumed by CPSD's allegations in the Records OII.

2. Absence Of Records Regarding The Pups

CPSD cites PG&E's lack of knowledge of the pups as an example of PG&E's purported failure to keep necessary and accurate records.[483] However, the Segment 180 job file shows PG&E ordered X52, 0.375-inch, DSAW pipe for the installation, and the records for Segment 180 contained specific information down to the level of tie-in details showing pipe lengths and elbows.[484] As Mr. Harrison explained, if PG&E had known about the pups during installation, it would have noted them in the job file given the other detail on the drawing, leading to the conclusion that PG&E "had no idea [the pups] existed."[485] Moreover, the recordkeeping provisions in ASA B31.1.8-1955 did not address the creation and maintenance of records of pipeline installations to the level of detail that would show the six pups.[486] For CPSD to claim that PG&E should have maintained a joint-by-joint level of detail for the 1956 Segment 180 construction is to hold PG&E to a standard that "doesn't even exist today in the industry."[487] CPSD provided no evidence that supports its attempt to enforce such a standard.

This allegation is also duplicative of CPSD's allegations from the Records OII.[redacted]

3. Clerical Errors In GIS Regarding Segment 180

CPSD alleges that errors related to Segment 180 in PG&E's GIS constitute violations of law.[489] Specifically, CPSD notes that PG&E's GIS misidentified Segment 180 as seamless pipe instead of DSAW; misclassified the Segment 180 pipe as X42 instead of X52 pipe; and

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[redacted]

[483] Ex. CPSD-5 at 34-35 (CPSD/Stepanian).

[484] Joint R.T. 253, 325 (PG&E/Harrison).

[485] Joint R.T. 364-68 (PG&E/Harrison).

[486] Ex. PG&E-1 at 7-1, n.1 (PG&E/Harrison).

[487] Joint R.T. 487 (PG&E/Harrison).

[redacted]

[489] Ex. CPSD-1 at 64-66 (CPSD/Stepanian).

erroneously recorded that Segment 180 was pressure tested in 1961.[490] None of these errors amount to a violation of law.

None of these errors in GIS had any impact on PG&E's integrity management assessment of Segment 180. Under 49 C.F.R. § 192.113, substituting the seamless designation with the correct information (DSAW) would have yielded the same longitudinal joint efficiency factor (1.0); neither the regulations nor ASME B31.8S consider either DSAW or seamless pipe to be subject to a long seam manufacturing threat.[491] Correcting the pipe's SMYS value from X42 to X52 results in a higher yield strength; thus GIS reflected a more conservative value.[492] And, as CPSD has acknowledged, in 1956 there were no state or federal regulations requiring pressure tests, thus the purported error regarding the 1961 gas test is of no import since PG&E did not use it to establish the MAOP.[493] In addition, as Mr. Harrison testified, the Segment 180 job file contains purchase records for materials that would have only been useful for a hydro test.[494] CPSD has not submitted any evidence to establish (and meet its burden) that the identified GIS errors could conceivably constitute a violation of law.

Lastly, again, CPSD's allegations regarding errors in GIS are duplicative of violations CPSD asserts in the Records OII.[redacted]

4. Brentwood Video

CPSD's rebuttal testimony appears to drop CPSD's prior allegation regarding PG&E's alleged failure to preserve video from a security camera inside the back up gas control room in Brentwood.[496] As discussed in [redacted] and Mr. Seager's testimony [redacted] a third-party contractor failed to enable the recording device for that camera, and therefore video from inside the Brentwood facility was never recorded on September 9, 2010.[497] CPSD's

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[490] Ex. CPSD-1 at 64 (CPSD/Stepanian).

[491] Ex. PG&E-1 at 5-9 (PG&E/Zurcher);*see* Joint R.T. 241 (PG&E/Harrison).

[492] Ex. PG&E-1 at 7-3 (PG&E/Harrison).

[493] Ex. CPSD-1 at 18 (CPSD/Stepanian).

[494] Joint R.T. 412-14 (PG&E/Harrison); *see* Ex. Joint-10 at HRG 0008, HRG 0019, HRG 0073, HRG 0095, HRG 0119, and HRG 0203.

[redacted]

[496] Ex. CPSD-5 at 34-35 (CPSD/Stepanian) (not addressing this alleged violation in its Rebuttal Testimony).

[497] Ex. PG&E-1 at 7-3 (PG&E/Seager); [redacted]

allegation that PG&E failed to preserve the Brentwood video in violation of the Commission's preservation order necessarily falls because the video never existed to be preserved.

CPSD's allegation regarding the Brentwood security camera video is also duplicative of violations CPSD asserts in the Records OII.[redacted]

D. PG&E's SCADA System And The Milpitas Terminal

CPSD alleges several violations related to PG&E's SCADA system and Milpitas Terminal: "The investigation found multiple deficiencies in PG&E's Control System at Milpitas Terminal which existed at the time of the incident and led to the loss of pressure control and deficiencies in the SCADA system that delayed the response by the Gas Operators. The investigation also found PG&E in violation of Part 192.13(c) for not following its own procedures related to system clearances and Part 192.605(c) for not having adequate procedures for recognizing abnormal operating conditions."[499]

The evidence does not support CPSD's allegations. The record establishes that alleged deficiencies at Milpitas Terminal and in PG&E's SCADA system did not result in a loss of pressure control or delay gas control's response to the rupture. The evidence is undisputed that the back-up pressure limiting system at Milpitas Terminal functioned as designed to keep the pressure on Line 132 and at the rupture site below MAOP, and well below regulatory maximums. The evidence also showed that PG&E's gas system operators' response to the rupture was reasonable under the circumstances they confronted. While PG&E acknowledges that the written clearance for the work at Milpitas Terminal on September 9, 2010, did not fully comply with PG&E's clearance policy and procedure, which PG&E recognizes constitutes a violation of Section 192.13(c), the record also established that the field crew and gas system operators followed good communication practices and took actions that furthered safety during the work at Milpitas Terminal.

1. The Local Control System At Milpitas Terminal Kept Pressure Below MAOP And Regulatory Limits

CPSD failed to prove that conditions at Milpitas Terminal and on PG&E's SCADA system on September 9, 2010 constituted an unsafe condition in violation of the law. The

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[redacted]

[499] Ex. CPSD-1 at 70 (CPSD/Stepanian).

evidence proves the opposite. When the pressure increased at Milpitas Terminal, PG&E's redundant pressure limiting system operated as designed and kept pressure on the outgoing pipelines below the MAOP and well below regulatory limits. [500] CPSD itself conceded, "At the time of the incident, the pressure on line 132 did not exceed the maximum pressure allowed by code."[501] Standing alone, that statement defeats CPSD's alleged violations related to Milpitas Terminal and SCADA.

Though not its burden, PG&E produced evidence refuting CPSD's allegations. In response to a PG&E data request, CPSD stated that the "[e]vidence of those monitor valves reviewed by CPSD shows they functioned as intended." [502] The monitor valves kept pressures in Milpitas Terminal and downstream on the Peninsula pipelines under MAOP and under the MAOP-plus-10% limit permitted for abnormal operations by 49 C.F.R. § 192.201. As both CPSD and the NTSB found, the pressure at Segment 180 did not exceed approximately 386 psig.[503] And as CPSD and the NTSB also acknowledged, the pressure increase from Milpitas Terminal would not have caused a non-defective pipe to rupture. [504] At the evidentiary hearing, Mr. Kazimirsky explained:

> WITNESS KAZIMIRSKY: [. . .] Like I said, it was related because the pressure increase did expose the defect in the pipe and the pipe ruptured. But that doesn't mean that anything, any operation at the Milpitas Terminal failed. Milpitas worked just the way it was supposed to design – it was supposed to work the way it was designed. Milpitas' control system maintained pressure under the limits of the operations.
>
> MR. LONG: Q: Okay.
>
> A: In that sense, the system worked. The fact that the pipe was defective resulted in a rupture. So they are related but only related. Milpitas was not the cause of the rupture.[505]

The evidence leads to only one conclusion – the pressure control system at Milpitas Terminal and PG&E's SCADA system functioned properly during the abnormal operating

[500] Ex. CPSD-1 at 8, 24 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 12, 124; Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-13 to 9-14 (PG&E/Miesner); Joint R.T. 193 (PG&E/Kazimirsky).

[501] Ex. CPSD-1 at 24 (CPSD/Stepanian).

[502] Ex. PG&E-5 (Tab 8-2).

[503] Ex. CPSD-1 at 8 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 12.

[504] Ex. CPSD-1 at 91 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 124.

[505] Joint R.T. 193 (PG&E/Kazimirsky).

condition on September 9, 2010 and maintained pressure at what should have been safe levels. [506] Expert witness Tom Miesner corroborated this conclusion:

> When the power issues at Milpitas Terminal caused the primary regulating valves to open, the pressure began to increase. When the pressure reached 386 psig on the outgoing pipelines, the monitor valves began to close to control the pressure. Pressure leaving Milpitas Terminal reached a high of approximately 396 psig before returning toward the established set point of 386 psig. The pressure on Line 132 at Milpitas Terminal did not reach the established MAOP of 400 psig, and did not reach the MAOP permitted under federal regulations (49 CFR § 192.201) during abnormal operations, MAOP plus 10%. The pressure at the rupture site on Segment 180 was limited to approximately 386 psig.
>
> In my opinion, based on my experience both as a consultant and as an operator in the pipeline industry, the redundant pressure limiting system at Milpitas Terminal is a safe and appropriate system for controlling gas pressure on the Peninsula transmission system pipelines, and that pressure limiting system functioned properly on September 9, 2010.[507]

Unable to show that the system failed (because it did not), CPSD bases its alleged violations on its perception of the conditions existing at Milpitas Terminal on September 9, 2010.[508] However, CPSD's perception does not establish a violation of law. The evidence demonstrated that PG&E upgraded Milpitas Terminal as recently as 2002; that at that time the station PLCs were replaced with the latest technology and upgraded software was installed; that the valve controllers were upgraded, as was the communication system between the PLCs and the controllers. [509] The equipment in the station was inspected and evaluated, including the power supplies that failed on September 9, 2010 (PS-A and PS-B), and they did not show signs of degradation.[510] When asked whether conditions at Milpitas Terminal created any safety issue, PG&E engineer Mark Kazimirsky stated:

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[506] Ex. CPSD-1 at 8, 24 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 12, 124; Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-13 to 9-14 (PG&E/Miesner); Joint R.T. 193 (PG&E/Kazimirsky).

[507] Ex. PG&E-1 at 9-13 to 9-14 (PG&E/Miesner).

[508] Ex. CPSD-1 at 94, 98 (CPSD/Stepanian) (describing allegedly aged equipment, loose wires, incomplete diagrams).

[509] Ex. PG&E-1 at 8-10 to 8-11 (PG&E/Kazimirsky/Slibsager); Joint R.T. 97-98 (PG&E/Kazimirsky/Slibsager).

[510] Ex. PG&E-1 at 8-10 to 8-11 (PG&E/Kazimirsky/Slibsager).

> I think Milpitas terminal equipment is in good shape, is well maintained. And I don't consider it obsolete or being in dangerous condition.[511]

In light of the fact that the control system functioned properly when called upon in an unexpected situation, and in the face of CPSD's vague allegations regarding unsafe conditions, Mr. Kazimirsky's conclusion must be considered correct.

CPSD concedes that it lacks a specific regulation or code to which it can point in asserting that "conditions" at Milpitas Terminal and on PG&E's SCADA system constituted violations of law: "There are no specific requirements in the federal or state codes which address the above conditions."[512] Notwithstanding its subjective contentions, CPSD cannot dispute that, on September 9, 2010, PG&E's SCADA system and local control system at Milpitas Terminal functioned as intended to prevent the pressure on Line 132 from exceeding MAOP.[513] CPSD also cannot dispute that absent the defective pup in Segment 180, the pressure increase on September 9, 2010 would have been a non-event.[514] CPSD did not even approach satisfying its burden of proof for these alleged violations.

2. Gas Control's Actions Did Not Violate Any Law

CPSD alleges that the actions of PG&E's gas control operators in response to the pressure increase and rupture constituted a violation of Section 451.[515] As discussed above in Section III.B, CPSD's use of Section 451 to assert broad and arbitrary safety violations is improper and cannot support this alleged violation. In any event, the evidence shows that PG&E's gas control operators responded appropriately in the situation they confronted, and that their actions did not violate any law.

The evidence established the following. Beginning at 5:22 p.m., unexpected power issues at Milpitas Terminal caused invalid and unreliable SCADA data and an unusual volume of

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[511] Joint R.T. 113 (PG&E/Kazimirsky/Slibsager); *see* Joint R.T. 89, 92, 98, 109-10 (PG&E/Kazimirsky/Slibsager).

[512] Ex. CPSD-1 at 99 (CPSD/Stepanian).

[513] Ex. PG&E-5 (Tab 8-2).

[514] Ex. CPSD-1 at 91 (CPSD/Stepanian) ("A properly constructed pipeline that met PG&E and industry standards during its installation in 1956 would have most likely withstood a pressure of 386 psig."). "Most likely" is an unwarranted qualifier; there is no reasonable dispute that properly-manufactured DSAW pipe of the Segment 180 specifications would withstand a pressure of 386 psig. Ex. CPSD-9 (NTSB Report) at 124; Ex. PG&E-1 at 3-5 (PG&E/Caligiuri).

[515] Ex. CPSD-1 at 70, 98-99 (CPSD/Stepanian).

SCADA alarms to come into PG&E's Gas Control Center.[516] Gas control operators trended and analyzed the mixture of incoming SCADA information and alarms to determine and confirm actual operating conditions at Milpitas Terminal and downstream on the outgoing transmission pipelines.[517] Gas control operators recognized that the pressure had increased at Milpitas Terminal and was also increasing on the outgoing Peninsula pipelines.[518] They also confirmed that the back-up pressure limiting system at Milpitas Terminal was working to stop the pressure from further increasing.[519] PG&E's gas control operators worked with the field crew at Milpitas Terminal to attempt to identify the source of the pressure increase.[520] At 5:52 p.m., even though the monitor control system was limiting the pressure, Gas Control remotely lowered the pressure on the pipelines coming in to Milpitas Terminal, which had the effect of lowering the gas pressure through Milpitas Terminal and on the outgoing pipelines.[521] Line 132 ruptured at 6:11 p.m., though the pressure never exceeded 396 psig at Milpitas Terminal and 386 psig at the rupture site.[522]

At the time of the rupture, PG&E's gas control operators had for approximately 50 minutes been receiving and attempting to integrate and analyze a mixture of valid and invalid SCADA data and alarms.[523] The low pressure readings and SCADA alarms related to the Line 132 rupture, which first came in at 6:15 p.m., were single data points among the mixture of valid and invalid information and alarms that had been occurring for nearly an hour.[524] The evidence showed that, at 6:29 p.m., just 2 minutes after first becoming aware of the fire in San Bruno,

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[516] Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8 (PG&E/Miesner).

[517] Ex. PG&E-1 at 8-5 to 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8 (PG&E/Miesner).

[518] Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8to 9-9 (PG&E/Miesner).

[519] Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner).

[520] Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8 to 9-9 (PG&E/Miesner).

[521] Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner). Mr. Slibsager explained that gas control operators were aware that the pressure was being controlled by the monitor valves but ultimately decided to lower pressure upstream as an added precaution. Joint R.T. 117 (PG&E/Slibsager) ("Q: What, if any, danger would there have been if the pressure was lowered to 370 while you were – while PG&E was diagnosing the issue, while PG&E was diagnosing its situational awareness? A: I think it could have been done. I think the operators didn't take that move at first because they understood that the control system, being the monitor overpressure protection devices at Milpitas, were maintaining the pressure through Milpitas at levels that should not have posed a risk to the system."). Both CPSD and the NTSB agree that the pressure increase experienced on September 9, 2010 should not have posed a risk to non-defective pipe. Ex. CPSD-1 at 91 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 124.

[522] Ex. PG&E-40 at 5; Ex. CPSD-1 at 8, 11 (CPSD/Stepanian); Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager).

[523] Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8 to 9-9 (PG&E/Miesner).

[524] Ex. PG&E-1 at 8-5 to 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8 to 9-9 (PG&E/Miesner).

PG&E's gas control operators connected the reports of the fire with the SCADA low pressure alarms on Line 132 to determine that there had likely been a line break on Line 132.[525]

It is easy after the accident, in hindsight, to pull from the voluminous SCADA data gas operators were analyzing the first low-low pressure alarm received at 6:15 p.m. and fault the operators for not immediately recognizing the possible line break. [526] But the criticism is not warranted, as emphasized in the Introduction (Section I) and worth repeating here:

> It is much easier *after* the event to sort the relevant from the irrelevant signals. After the event, of course, a signal is always crystal clear; we can now see what disaster it was signaling, since the disaster has occurred. But before the event it is obscure and pregnant with conflicting meanings. It comes to the observer embedded in an atmosphere of "noise," i.e., in the company of all sorts of information that is useless and irrelevant for predicting the particular disaster.[527]

Under the circumstances the gas control operators confronted, in particular the length of time they were dealing with multiple and contradictory alarms and SCADA data (the "noise"), their response and conduct were reasonable and timely. [528] SCADA and operator control expert Tom Miesner testified:

> In my opinion, given the mixture of valid and invalid SCADA data and alarms that gas control operators had to integrate and analyze for nearly an hour before and after the rupture, the time in which PG&E's gas control operators determined that the low pressure readings starting at 6:15 p.m. were valid and that there had likely been a line break on Line 132 was reasonable.[529]

Mr. Miesner also testified that the gas control operators responded appropriately after determining that there had been a line break on Line 132:

> On September 9, 2010, the remote shut off valves that were available to PG&E's gas control operators to isolate the Line 132 rupture were located in Milpitas Terminal and Martin Station, approximately 46 miles apart. Because of the cross-ties between

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[525] Ex. PG&E-40 at 6; Ex. PG&E-1 at 8-6 to 8-7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner); Ex. CPSD-1 at 11 (CPSD/Stepanian).

[526] Ex. CPSD-1 at 95-98 (CPSD/Stepanian); Ex. CPSD-5 at 39 (CPSD/Stepanian).

[527] Nate Silver, *The Signal and the Noise*, Penguin Press (2012) at 418 (citing Roberta Wohlstetter, *Pearl Harbor: Warning and Decision*, Stanford Univ. Press (1962) at 387 [emphasis in original]).

[528] *See, e.g.,* Joint R.T. 168-69 (PG&E/Kazimirsky).

[529] Ex. PG&E-1 at 9-9 (PG&E/Miesner). Adding redundant SCADA data to the mix, as CPSD suggests, would have only complicated the information with which gas operators had to deal. *See* Joint R.T. 128-30 (PG&E/Slibsager).

> the three Peninsula transmission pipelines, gas control operators would have been required to close the valves at Milpitas Terminal for all three pipelines feeding the San Francisco Peninsula to prevent new gas from entering the system. Taking that action would have created unintended and severe public safety risks to a large population. For example, an uncontrolled gas shut down puts critical facilities, such as hospitals and power generation plants, at risk, as well as putting at risk the people who rely on those facilities. An uncontrolled shut down also creates the risk of residual gas entering residences and other buildings after pilot lights and furnaces have gone out due to insufficient gas pressure. Large gas outages increase the likelihood that people will take self-help actions, such as using space heaters or attempting to relight pilot lights themselves, which can create disastrous results if gas has gotten into buildings due to the loss of pressure during an outage. Moreover, shutting the valves at Milpitas Terminal and Martin Station would not have stopped the gas already in the pipeline system from continuing to escape through the rupture.[530]

In conjunction with the SCADA and local control system at Milpitas Terminal, PG&E's gas control operators responded to the unexpected pressure increase on Line 132 and took appropriate action. They maintained the pressure below MAOP. Following the rupture, gas control operators recognized that there had likely been a line break in San Bruno and reacted. Even assuming Section 451 could support an alleged violation, the record demonstrates that the gas control operators' conduct in no way constitutes a violation of law.

3. PG&E Acknowledges The Clearance Violation; However, PG&E's Personnel Acted Consistent With Clearance Objectives And Procedures

PG&E recognizes that the clearance documentation for the electrical work at Milpitas Terminal was not as it should have been, and did not fully comply with PG&E's written clearance policy and procedure.[531] PG&E acknowledges this shortcoming constitutes a violation of 49 C.F.R. § 192.13(c).

In evaluating the severity of the violation, however, the Commission should consider some additional evidence in the record. Despite the clearance documentation shortcoming, the field crew and gas system operators followed good communication practices and took actions

[530] PG&E-1 at 9-9 to 9-10 (PG&E/Miesner); R.T. 863 (PG&E/Miesner).

[531] Ex. PG&E-1 at 8-8 (PG&E/Kazimirsky/Slibsager).

focused on safety.[532] Prior to beginning work, the crew at Milpitas Terminal conducted pre-work meetings (tailboards) at which they addressed safety issues, discussed the day's project, and outlined the steps they would follow. [533] When ready to begin, the lead gas control technician called Gas Control to alert them that the clearance was beginning, and as the work progressed, the gas control technician called Gas Control several more times. [534] The purpose of these calls was to alert the gas system operators, prior to disconnecting the designated electrical equipment, that they were about to take a step in the project that could affect Gas Control's ability to monitor the system at Milpitas Terminal. [535] These clearance communications ensured that both the field crew and the gas system operators were aware that intermittent SCADA interruptions could occur as part of the process.[536]

The evidence showed that the field crew also took precautions when the steps they were taking could potentially impact Gas Control's ability to see or control the system at Milpitas Terminal. Prior to moving the connections for the Genius Blocks, the gas transmission technician switched the valve controllers into manual, after documenting the pressures at each controller.[537] While it was not expected that disconnecting power to the Genius Blocks would impact the valve controllers, the crew put the controllers into manual as an added precaution. [538] Once the Genius Blocks were reconnected to the temporary UPS device, the gas transmission technician and the contract engineer put the controllers back into automatic and rechecked the pressures at each controller to confirm they were functioning properly and that no pressure impact had occurred. [539] When the crew had completed the steps in the electrical work they planned for the day, at approximately 5 p.m., the control system at Milpitas Terminal was functioning and no problems were occurring.[540]

As Mr. Slibsager testified, the field crew followed good clearance practices and kept gas control operators informed of the status and potential impacts of the work:

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[532] Ex. PG&E-1 at 8-8 to 8-10 (PG&E/Kazimirsky/Slibsager); Joint R.T. 146-47, 149-50 (PG&E/Slibsager).

[533] Ex. PG&E-1 at 8-8 (PG&E/Kazimirsky/Slibsager). A pre-construction meeting was also held in August. Ex. PG&E-1 at 8-8 n.5 (PG&E/Kazimirsky/Slibsager).

[534] Ex. PG&E-1 at 8-8 to 8-9 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-5 (Tab 8-1).

[535] Ex. PG&E-1 at 8-8 to 8-9 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-5 (Tab 8-1).

[536] Ex. PG&E-1 at 8-9 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-5 (Tab 8-1); Joint R.T. 146-50 (PG&E/Slibsager).

[537] Ex. PG&E-1 at 8-9 (PG&E/Kazimirsky/Slibsager).

[538] Ex. PG&E-1 at 8-9 (PG&E/Kazimirsky/Slibsager).

[539] Ex. PG&E-1 at 8-9 (PG&E/Kazimirsky/Slibsager).

[540] Ex. PG&E-1 at 8-9 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 86 (CPSD/Stepanian).

> In other words, they followed the work procedure in respect the field called in, established contact and information with the control room with what they were going to do and what would transpire. The person they were talking to is an individual, it is a control tech who can fill that role. And I just have to assume that my control room understood that person was able to fill the clearance supervisor role given the qualifications.[541]

Mr. Kazimirsky underscored that the planned work was not expected to impact the gas system:

> The work that was performed that day did not or would not impact system operations. It would impact data going to SCADA. But as far as gas flowing on the line, it wouldn't be impacted. That is why they didn't feel there was a need for preplanning for abnormal operations. Nothing what they did there would have interrupted normal system operations.[542]

Although an unplanned pressure increase occurred, that resulted from an unexpected failure of two power supplies not involved in the clearance work that day.[543] And as noted above, both CPSD and the NTSB concluded that the redundant pressure limiting system at Milpitas Terminal functioned properly and that a non-defective pipe would not have ruptured from the pressure increase.[544]

4. Post-Accident Alcohol Testing

CPSD alleges, "PG&E failed to conduct prompt alcohol testing of the operators doing the Milpitas work in violation of Part 199.225."[545] PG&E agrees.

Section 199.225 requires that post-incident alcohol testing be conducted at the latest within 8 hours of an incident, and if testing is not done within the first 2 hours, that the operator prepare "a record stating the reasons the test was not promptly administered."[546] 49 C.F.R. § 199.225(a). PG&E did not conduct alcohol testing of the personnel working on the clearance

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[541] Joint R.T. 143-44 (PG&E/Slibsager).

[542] Joint R.T. 150-51 (PG&E/Kazimirsky).

[543] Joint R.T. 92, 150-51 (PG&E/Kazimirsky)

[544] Ex. CPSD-1 at 91 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 124; *see* PG&E-1 at 3-5 (PG&E/Caligiuri); Ex. PG&E-1 at 9-12 to 9-14 (PG&E/Miesner).

[545] Ex. CPSD-1 at 163 (CPSD/Stepanian).

[546] 49 C.F.R. § 199.225(a).

at Milpitas Terminal within 8 hours after the accident, and did not create a record explaining the reasons for the delay.[547]

PG&E has revised its DOT reportable incident drug and alcohol testing protocol to improve performance in this area.[548]

E. PG&E's Emergency Response

CPSD summarily alleges that PG&E violated 49 C.F.R. §§ 192.605 and 192.615 pertaining to emergency response plans, and Public Utilities Code Section 451 for inadequately responding to a major incident.[549] With the benefit of hindsight, CPSD identified areas for PG&E to improve, which PG&E has addressed. Even with hindsight, however, CPSD has not alleged any specific act or omission that amounts to a legal violation. CPSD has not and cannot meet its burden of proving that PG&E's conduct violated Section 192.605, Section 192.615, or Public Utilities Code Section 451.

1. PG&E's Response Time Did Not Violate Any Law

CPSD notes the NTSB's comment that 95 minutes to stop the flow of gas by isolating the rupture site was excessive.[550] This conclusion is unsupported by the evidence. Rather, the record establishes that 95 minutes was not "excessive."[551] Moreover, such a finding does not amount to a violation of law. As CPSD acknowledges, "no specific regulations exist pertaining to emergency response time."[552] No federal or state regulation or law addresses requirements for response time. Nor does CPSD attempt to expl ain what "excessive" means in light of the relevant facts, or as applied to the regulations it cites. In fact, CPSD acknowledges that there are a "multitude of variables" present in responding to an emergency, providing as examples "the severity of the leak, vintage and material of the pipe, weather and traffic conditions, proximity to nearby personnel and equipment, utility resources, and the time of day."[553] CPSD further notes

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[547] Ex. CPSD-1 at 100 (CPSD/Stepanian); R.T. 252 (PG&E/Oceguera). All personnel tested negative for both drugs and alcohol. Ex. CPSD-1 at 99-100 (CPSD/Stepanian).

[548] Ex. PG&E-1 at 8-23 to 8-25 (PG&E/Oceguera); R.T. 247-63 (PG&E/Oceguera); Ex. PG&E-1a, Appendix A (PG&E/Yura); Ex. PG&E-38.

[549] Ex. CPSD-1 at 103 (CPSD/Stepanian).

[550] Ex. CPSD-1 at 107 (CPSD/Stepanian).

[551] R.T. 415-16 (PG&E/Bull).

[552] Ex. CPSD-1 at 102 (CPSD/Stepanian).

[553] Ex. CPSD-1 at 107 (CPSD/Stepanian).

that a U.S. Department of Transportation study concluded there was "insufficien t data to establish an appropriate standard time to isolate a ruptured pipeline section."[554]

In the absence of a relevant regulation, CPSD points to 49 C.F.R. § 192.615(a)(3)(iii). Section 192.615(a)(3)(iii) discusses the required elements of a written emergency plan, not response times:

> (a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following: . . .
>
> (3) Prompt and effective response to a notice of each type of emergency, including the following: . . .
>
> (iii) Explosion occurring near or directly involving a pipeline facility.

At the time of the San Bruno accident, PG&E had written procedures that provided for the prompt and effective[555] response to an incident occurring near or directly involving a pipeline facility.[556] PG&E's emergency response plans contain each of the elements required by the regulation, 49 C.F.R. § 192.615.[557] David Bull, an expert on emergency response plans and the federal regulations, reviewed PG&E's written plans and testified that they were in compliance with the regulation.[558] CPSD offered no testimony to the contrary. In fact, in the two years before the accident CPSD audited PG&E's emergency plans and deemed them to be satisfactory under the same regulations.[559] [redacted]

Moreover, the evidence shows that PG&E's response was reasonable, ad equate, effective and prompt.[561] PG&E initiated its response immediately after becoming aware of the event a few minutes after the rupture. PG&E dispatched multiple field personnel and coordinated on

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[554] Ex. CPSD-1 at 105 (CPSD/Stepanian).

[555] In the Records OII, CPSD also makes allegations relating to this regulation and the effectiveness of PG&E's plan. CPSD cannot duplicate alleged violations in each proceeding.

[556] Ex. PG&E-39 (PG&E Company Gas Emergency Plan); Ex. PG&E-42 (PG&E Gas T&D Emergency Plan Manual).

[557] Ex. PG&E-1 at 11-10, 11-11 to 11-25 (PG&E/Bull); R.T. 414-15 (PG&E/Bull).

[558] Ex. PG&E-1 at 11-5 to 11-23 (PG&E/Bull); R.T. 414-15 (PG&E/Bull); Ex. PG&E-39 (PG&E Company Gas Emergency Plan); Ex. PG&E-42 (PG&E Gas T&D Emergency Plan Manual).

[559] Ex. PG&E-1 at 10-2 (PG&E/Almario); Ex. PG&E-1, Appendix A (PG&E/Almario).

[redacted]

[561] R.T. 269 (PG&E/Almario); R.T. 415-16 (PG&E/Bull); R.T. 861-62 (PG&E/Miesner).

scene with the San Bruno Fire Department. [562] Mr. Bull rev iewed PG&E's response and found that the response was prompt and effective. [563] By contrast, CPSD offered no testimony or analysis by an emergency response expert or any other expert to support the conclusion that PG&E's response time was "excessive." Nor can it. A review of PG&E's response demonstrates that PG&E acted promptly and effectively.

The rupture occurred at 6:11 p.m. [564] PG&E responded as soon as it became aware of the event and began dispatching resources. [565] Within seven minutes of the rupture, at 6:18 p.m., PG&E's dispatcher began receiving calls about the incident. [566] Five minutes later, at 6:23 p.m., PG&E's dispatcher had gathered information and dispatched a gas service representative to Sneath Lane and Skyline Boulevard in San Bruno to investigate the reported explosion. [567] It was rush hour and the roads were crowded. [568] At 6:25 p.m., PG&E's dispatcher contacted the Peninsula Division On-Call Supervisor, who then began making call outs of more field personnel.[569] PG&E's dispatch also called Gas Control at 6:27 p.m.[570]

PG&E's personnel acted promptly and effectively, even personnel who were not on -duty. At 6:35 p.m., a PG&E M&C mechanic saw the fire from his house and headed immediately to PG&E's Colma Yard to retrieve a truck and tools. [571] The M&C mechanic recognized through his training and experience that the fire was consistent with a fire fueled by natural gas. [572] While en route, five minutes later at 6:40 p.m., the M&C mechanic was contacted by the Peninsula Division On-Call Supervisor, who instructed him to report to the Colma Yard. [573] Already on his way, the M&C mechanic continued to the yard, arriving at 6:50 p.m. [574] He arrived and gathered

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[562] R.T. 415-16 (PG&E/Bull); Ex. PG&E-40 at 6-10.
[563] R.T. 415-16 (PG&E/Bull); Ex. PG&E-1 at 11-25 to 11-28 (PG&E/Bull).
[564] Ex. PG&E-40 at 5; R.T. 370 (PG&E/Almario).
[565] R.T. 415-16 (PG&E/Bull).
[566] Ex. PG&E-40 at 6; R.T. 377-78 (PG&E/Almario).
[567] Ex. PG&E-40 at 6.
[568] R.T. 380-81 (PG&E/Almario).
[569] R.T. 381-82 (PG&E/Almario); Ex. PG&E-40 at 7.
[570] Ex. PG&E-40 at 7.
[571] R.T. 382-85, 392-93 (PG&E/Almario); Ex. PG&E-40 at 8.
[572] R.T. 864 (PG&E/Miesner); Ex. CPSD-96 at 6, 10-14
[573] R.T. 382 (PG&E/Almario); Ex. PG&E-40 at 9.
[574] Ex. PG&E-40 at 10; R.T. 389-90 (PG&E/Almario).

his tools and maps.[575] He also spoke with his Supervisor about the plan to isolate the rupture; the Supervisor approved the plan and directed that it be carried out.[576] Another M&C mechanic had also been directed to report to the Colma Yard.[577] (Two mechanics are needed to shut the valves, which often are large, difficult to turn and isolated underground.[578]) At 7:06 p.m., the two M&C mechanics left the yard to close valves and isolate the rupture.[579]

The M&C mechanics arrived at the first valve location at 7:20 p.m. and closed the valve by 7:30 p.m.[580] In the meantime, at 7:29 p.m., Gas Control remotely closed the valves at Martin Station, isolating the pipeline north of the rupture but several miles distant.[581] Meanwhile, the two M&C mechanics, joined by a T&R Supervisor, traveled to and closed two additional valves north of the rupture, isolating the rupture at the closest possible locations.[582]

The record thus establishes that PG&E personnel were effective, prompt and provided a reasonable response in difficult circumstances. CPSD's bare assertion that the response time was "excessive" does not prove a violation, especially in light of the concrete evidence of PG&E's response.

2. Fire And Police Were On The Scene By The Time PG&E Learned Of The Incident; PG&E Did Not Violate The Law By Not Calling 911

CPSD criticizes PG&E for not calling 911 at the time PG&E recognized a potential line rupture. Fire and police responders, however, were on the scene within minutes of the incident, even before PG&E was notified.[583] The rupture occurred at 6:11 p.m.[584] The first San Bruno Police Department resources were dispatched at 6:11 p.m. and arrived at 6:12 p.m.[585] The San Bruno Fire Department's alarm sounded at 6:12 p.m., and the first fire department unit arrived at

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[575] R.T. 390 (PG&E/Almario).

[576] R.T. 391 (PG&E/Almario); Ex. PG&E-40 at 11.

[577] Ex. PG&E-40 at 9.

[578] R.T. 391-92 (PG&E/Almario).

[579] Ex. PG&E-40 at 11; R.T. 391 (PG&E/Almario); Ex. CPSD-96 at 10-25.

[580] Ex. PG&E-40 at 11-12; R.T. 393 (PG&E/Almario). Transmission line valves are large and require substantial strength and several minutes to close.

[581] Ex. PG&E-40 at 12.

[582] Ex. PG&E-40 at 13. As the M&C mechanics were closing the final valves, at 7:42 p.m. a PG&E Superintendent contacted Gas Control from the incident site to notify it that the flames had diminished.

[583] R.T. 378 (PG&E/Almario); Ex. PG&E-40 at 5-6.

[584] R.T. 370 (PG&E/Almario); Ex. PG&E-40 at 5.

[585] R.T. 370-71 (PG&E/Almario); Ex. PG&E-40 at 5.

6:17 p.m.[586] PG&E was side-by-side with the police and fire personnel within approximately 28 minutes of the incident.[587]

Not calling 911 in this situation does not violate the requirements of 49 C.F.R. § 615(a)(8), which provides:

> (a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
>
> > (8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

PG&E's written procedures provide for notifying the appropriate fire and police officials.[588] On September 9, 2010, PG&E personnel directly interacted and coordinated with the appropriate fire and police officials. When PG&E personnel arrived on the scene, the fire and police were already there.[589] As emergency response expert David Bull testified, the notification and coordination requirement was fulfilled at the time PG&E personnel arrived at the scene, confirmed that there was a gas emergency and that additional emergency action should take place.[590] PG&E personnel thereafter worked hand-in-hand with the fire and police first responders. In fact, San Bruno Fire Chief Dennis Haag complimented the coordination between PG&E and the fire department as "great."[591]

As this evidence shows, the lack of a call to 911 neither violated the law nor adversely affected the response to the emergency. PG&E's field personnel were working directly with the public agency first responders within 30 minutes of the rupture.[592] Agency first responders were both aware of and on the scene of the accident before PG&E even knew about it; PG&E personnel in the field began working with first responders as soon as PG&E was on site. That

[586] R.T. 370-71 (PG&E/Almario); Ex. PG&E-40 at 5.
[587] R.T. 285 (PG&E/Almario); Ex. PG&E-40 at 5.
[588] Ex. PG&E-39 at 1-40, 1-47, IV-20; Ex. PG&E-1 at 11-24 to 11-25 (PG&E/Bull).
[589] R.T. 378 (PG&E/Almario); Ex. PG&E-40 at 5-6.
[590] R.T. 420-21 (PG&E/Bull).
[591] Ex. PG&E-41 at 469.
[592] R.T. 282-83, 285 (PG&E/Almario); Ex. PG&E-40 at 10.

gas control did not call 911, when fire and police were already aware of the event and working with PG&E employees on site, does not support a violation of law.[593]

At the time of the accident, PG&E's Gas Control did not have a specific policy that directed gas control operators to contact 911. Neither federal nor state regulations required gas control operators to contact 911 during an emergency event, thus the absence of a 911 policy and a call to 911 cannot support a legal violation. However, in response to an NTSB recommendation, PG&E has developed and implemented such a policy.[594] As Mr. Slibsager testified:

> MR. REIGER: Q: Do you know if gas control operators called 9-1-1?
>
> WITNESS SLIBSAGER: A: My operators did not call 9-1 -1 on the day of the accident.
>
> Q: Do you believe that was unreasonable?
>
> A: At the time of the accident we didn't have a policy or procedure that actually directed them to do that. Our response had typically been working with our field employees on scene, that if they needed our assistance in making any phone calls, that we would assist them in doing that. We have since changed that policy, and we now have a 9-1 -1 procedure based on the recommendation by the NTSB.[595]

The NTSB deemed PG&E's revised 911 policy "acceptable" in response to its safety recommendation and has closed this item.[596]

3. CPSD Identifies Areas For Improvement, But Does Not Allege Legal Violations Regarding Aspects Of PG&E's Emergency Response

CPSD alleges "deficiencies" in the areas of training, geographical area monitoring, coordination with internal personnel, and emergency response decision-making.[597] As the evidence discussed above shows, PG&E's emergency response was not deficient.[598] The issues

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[593] R.T. 420-21 (PG&E/Bull).
[594] Ex. PG&E-1 at 10-10 (PG&E/Dickson).
[595] Joint R.T. 121 (PG&E/Slibsager); R.T. 372-73, 374-76 (PG&E/Almario); Ex. PG&E-1 at 10-6 (PG&E/Dickson).
[596] Ex. PG&E-38 at 2 (NTSB Letter).
[597] Ex. CPSD-1 at 102 (CPSD/Stepanian).
[598] R.T. 410 (PG&E/Almario).

CPSD raises were identified with the benefit of hindsight and an after-the- fact review of PG&E's multi-faceted response to the San Bruno accident. CPSD identifies areas for improvement, but does not present evidence that any of the purported "deficiencies" amount to a violation of the law. In response to suggestions from a variety of sources, PG&E has made a number of improvements since the incident, including with respect to emergency response.[599]

a. Training

CPSD observes, "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."[600] CPSD does not allege this to be a violation of law, as there is no legal requirement to have such training. During the event, however, the responding M&C mechanic immediately recognized the possibility that the fire was fed by natural gas.[601] At other times, there were conflicting reports about the source of the fire being a gas station fire or a jet fuel fire from a plane crash.[602] CPSD recommended that PG&E provide training on fire identification, and PG&E has developed specific training to address this issue.[603] The training includes instruction regarding how to determine the nature of the fire, for example by considering the color of the flame and the type of smoke.[604]

b. Geographical Area Monitoring

CPSD contends Gas Control Room geographical monitoring responsibilities were "arbitrary."[605] Again, CPSD did not allege a legal violation, as no regulation addressed the method of assigning monitoring responsibilities in a gas control room. Rather, CPSD recommended that PG&E modify its procedur es to be more "efficient."[606] PG&E's method of monitoring its gas system had benefits. For example, it allowed multiple operators to have an

[599] *See* Ex. PG&E-1 at 10-6 to 10-11 (PG&E/Dickson);*see generally* Ex. PG&E-1a (PG&E/Yura).

[600] Ex. CPSD-1 at 102, 123 (CPSD/Stepanian).

[601] *See, e.g.*, Ex. PG&E-40 at 8 (upon seeing flames from the San Bruno fire from his house, PG&E M&C mechanic reports to PG&E's Concord dispatcher that "the flame that is coming out is consistent with a transmission line."); Ex. PG&E-1 at 10-4 (PG&E/Almario).

[602] *See, e.g.*, Ex. PG&E-40 at 11 (San Mateo County Sheriff called PG&E dispatch to ask if PG&E was aware of a "plane crash.").

[603] Ex. PG&E-1 at 10-9 (PG&E/Dickson).

[604] Ex. PG&E-1 at 10-9 (PG&E/Dickson).

[605] Ex. CPSD-1 at 117-18 (CPSD/Stepanian).

[606] Ex. CPSD-1 at 117-18 (CPSD/Stepanian).

overall view of the system, thereby creating a check through shared review and collaboration on proper operational actions. [607] Nonetheless, geographically-assigned monitoring also has advantages, thus PG&E modified its Gas Control Room procedures to implement geographically assigned monitoring.[608]

c. Coordination With Internal Personnel

CPSD contends that internal communication procedures for Gas Dispatch and Gas Control should be modified "to operate more efficiently." [609] CPSD does not allege that PG&E's internal communications procedures during its emergency response violated the law. [610] PG&E had written procedures for internal communications that complied with the law, including instructions, checklists and policies that describe the internal communications required in an emergency.[611] In pursuit of continual improvement, PG&E has revised its Gas Emergency Response Plan and implemented new Control Room Management procedures. [612] These procedures delineate roles and responsibilities during normal and emergency operating conditions, and are intended to improve communication and coordination among PG&E personnel.[613]

d. Emergency Response Decision Making

CPSD recommends that PG&E revise its procedures to clarify emergency response responsibilities.[614] CPSD claims the position responsible for dispatching crews to shut specific valves in the case of an emergency is unclear.[615] PG&E's emergency response plans set forth the roles and responsibilities of various personnel in an emergency, including the gas construction crew and supervisors. [616] CPSD is wrong to assert that there was a lack of supervision or direction regarding the shut down of valves. The on-call supervisor dispatched two M&C

[607] Ex. PG&E-1 at 10-3 (PG&E/Almario); R.T. 290-92 (PG&E/Almario).
[608] Ex. PG&E-1 at 10-3 (PG&E/Almario).
[609] Ex. CPSD-1 at 117 (CPSD/Stepanian).
[610] Ex. CPSD-1 at 117 (CPSD/Stepanian).
[611] Ex. PG&E-1 at 11-24 (PG&E/Bull);*see also id.* at 11-23.
[612] Ex. PG&E-1 at 10-6 to 10-7 (PG&E/Dickson).
[613] Ex. PG&E-1 at 10-6 to 10-9 (PG&E/Dickson).
[614] Ex. CPSD-1 at 122 (CPSD/Stepanian).
[615] Ex. CPSD-1 at 120 (CPSD/Stepanian).
[616] Ex. PG&E-39 at 1-30 to 1-31.

mechanics to isolate the rupture, one of whom had self-responded immediately upon seeing the flames though off-duty.[617] CPSD is also incorrect in its statement that the M&C mechanics were told to wait a t the Colma Yard, but "fortunately, the mechanics forewent waiting for official orders."[618] While preparing their tools and truck at the yard, the M&C mechanics conferred with their supervisor, who directed them to shut down the appropriate valves as expeditiously as possible, as they are trained to do in an emergency.[619]

F. PG&E's Safety Culture And Financial Priorities

CPSD has not alleged any violations based solely on PG&E's past spending on its gas transmission business. However, CPSD asserts that "manage ment failing to foster a culture that values safety over profits at PG&E" was one of a number of factors that "contributed to" the San Bruno accident and that "together constitute an unreasonably unsafe condition" in violation of Public Utilities Code Section 451. [620] In addition, CPSD makes a number of recommendations based on its conclusions about PG&E's past spending on, and the revenues generated by, its gas transmission and storage business.[621] Yet CPSD has failed to prove that PG&E's spending on its gas transmission and storage business constituted or contributed to any violation or that there is any basis for penalizing PG&E based on its past financial priorities or "safety culture."

CPSD relies in large part on the report of Overland Consulting ("Overland") and the testimony of Overland's lead consultant, Gary Harpster, for its claims relating to PG&E's past spending.[622] The cornerstone of Overland's analysis is its conclusion that PG&E spent less on capital expenditures and operations and maintenance costs for its gas transmission and storage business than the amounts implicit in the approved revenue requirements and rates. [623] For most

[617] Ex. PG&E-40 at 9-10; R.T. 389-90 (PG&E/Almario).

[618] Ex. CPSD-1 at 122 (CPSD/Stepanian); R.T. 417 (PG&E/Bull).

[619] R.T. 391 (PG&E/Almario); Ex. PG&E-40 at 11; Ex. PG&E-1 at 10-5 (PG&E/Almario); Ex. PG&E-39 at 1-29 to 1-31.

[620] Ex. CPSD-1 at 162 (CPSD/Stepanian).

[621] Ex. CPSD-1 at 168 (CPSD/Stepanian) (Recommendations 31-33).

[622] Gary Harpster of Overland was the principal author of the Overland Report (Ex. CPSD-168). CPSD later offered rebuttal testimony from Mr. Harpster (Ex. CPSD-170), who also was cross-examined at the evidentiary hearing. While PG&E typically uses "Overland" when discussing statements or findings in the Overland Report, throughout this section "Overland" and "Mr. Harpster" are sometimes used interchangeably.

[623] In this section, PG&E refers to its gas transmission and storage line of business as "GT&S." PG& E refers to operations and maintenance expenses as "O&M" and capital expenditures as "capex." These are the terms used throughout the cited testimony and exhibits.

of the relevant years, the Commission's decisions do not explicitly set forth adopted capital and expense forecasts, which makes it necessary to use judgment to estimate those amounts. Overland used flawed methods in doing so, however, and the Commission should not rely on its conclusions. In fact, as shown by the testimony of Matthew O'Loughlin, PG&E spent more, not less, than the amounts implicit in revenue requirements and rates. Moreover, both Overland and Mr. O'Loughlin found that PG&E spent more on *safety-related* capital than the amounts in revenue requirements and rates during the years in which they analyzed that issue. And, even if PG&E had spent somewhat less than the amounts implicit in revenue requirements and rates, that fact alone would not be a basis for penalizing PG&E.

CPSD's recommendations are also based on Overland's analysis showing that the GT&S business generated more in revenues than PG&E spent within that business and, on average, earned more than the authorized rate of return for the GT&S business. PG&E agrees with these findings but disagrees with CPSD about their significance. In the first place, PG&E's competitive storage business thrived during much of the time period due to the rate structure and incentives approved by the Commission in the GT&S rate cases combined with favorable external market conditions. Furthermore, the fact that a single line of business such as GT&S earned higher than authorized rates of return says nothing about whether PG&E, as a utility, valued profits over safety. Looking at the utility as a single entity – as it was managed – PG&E earned returns that were consistent with the authorized rates of return.

Overland's report also addresses the purported operational impacts of PG&E's spending and budgetary priorities, but Overland's conclusions are unreliable because they are colored by its mistaken view that PG&E spent less than the amounts implicit in revenue requirements and rates. Overland did not identify any specific spending decision that raises safety concerns or that shows that PG&E did not care about safety. In particular, Overland never identified any impact to Line 132 that it claimed was based on spending or budget priorities. As PG&E's expert witness Joseph Martinelli testified, PG&E did not change or defer planned integrity management assessments for Line 132 based on budgetary considerations.[624]

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[624] Ex. PG&E-1 at 12-1 to 12-4 (PG&E/Martinelli).

Lastly, CPSD's broad-brush attack on PG&E's safety culture in its own report is so rife with unsupported innuendo and irrelevant conjecture, and so lacking in facts, that it fails to prove anything, much less that PG&E prioritized financial performance over safety.[625]

1. PG&E Did Not Spend Less On Its Gas Transmission And Storage Business Than The Amounts Implicitly Included In Rates

a. Comparing The Capital And Expense Amounts Implicit In Rates To What PG&E Actually Spent

CPSD asked Overland to compare PG&E's "actual gas transmission safety-related O&M expenses and capital expenditures to the levels included in rates."[626] PG&E similarly asked Matthew O'Loughlin of The Brattle Group to prepare an independent comparison of PG&E's actual GT&S O&M expenses and capital expenditures to the amounts provided for in authorized revenue requirements and rates.[627] This exercise is more challenging than it might sound, because, for most of the years at issue, the Commission decisions and settlement documents do not explicitly set forth the O&M and capital amounts supporting the declaration of the authorized rates. CPSD and PG&E use the term "imputed adopted amounts" to refer to the O&M and capex amounts *implicitly* provided for in rates.[628]

In a fully litigated case, the Commission typically adopts explicit O&M and capex forecasts that it then uses to calculate a revenue requirement that, in turn, is used to set the approved rates.[629] In the case of a settlement, however, the settlement agreement (or the Commission decision approving the settlement) may not provide the same level of detail about the cost of service elements used to determine the settlement revenue requirement or rates as would be available in a fully litigated case. Four of the five GT&S rate cases covering 1997-2010 were resolved by settlement. The sole fully litigated case covered only one of the 14 years at issue – 2004.[630] The amount of detail included in the GT&S rate case settlements varies from case to case. Generally, however, the settlements do not include detailed cost of service

[625] Ex. CPSD-1 at 126-61 (CPSD/Stepanian).

[626] Ex. CPSD-168 at 1-2 (CPSD/Harpster); R.T. 56 (CPSD/Harpster).

[627] Ex. PG&E-10, MPO-1 at 1-2 (PG&E/O'Loughlin).

[628] *See, e.g.*, R.T. 61-62 (CPSD/Harpster).

[629] R.T. 73-74 (CPSD/Harpster).

[630] *See Application of Pacific Gas and Electric Company, etc.,* D.03-12-061, 2001 Cal. PUC LEXIS 1279 (excerpted in Ex. PG&E-19).

information for at least some of the rate case period. [631] Notwithstanding this lack of cost-related detail, the Commission approved all of the settlements in fully reasoned decisions.[632]

The following is an overview of the available information for each rate case period:

Gas Accord I (1997-2002): Under the terms of the Gas Accord I settlement, the 1997 revenue requirement is based on the GT&S portion of the revenue requirement adopted as part of the 1996 General Rate Case (GRC) (before GT&S was carved out into a separate rate case proceeding). The settlement agreement and workpapers provide information about the escalation of the revenue requirement (and the individual components of the revenue requirement) in 1998 through 2002.[633]

2003 Rate Case (also known as the Gas Accord I extension or Gas Accord II): The 2003 rate case settlement extended 2002 rates for another year without change and kept the Gas Accord I structure in place. The settlement agreement does not include a revenue requirement or other cost of service information.[634]

2004 Rate Case (also known as Gas Accord II): This was a fully litigated case with detailed cost of service information.[635]

Gas Accord III (2005-2007) : The Gas Accord III settlement provides cost of service information supporting the settlement rates for 2005. For the later years, the settlement provides a revenue requirement and information about O&M and capex escalation but not explicit adopted O&M or capex amounts.[636]

Gas Accord IV (2008-2010) : The Gas Accord IV settlement explicitly provides a revenue requirement for each year of the settlement and information about how the settlement revenue requirement and rates relate to the 2007 revenue requirement and rates (set in the Gas

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[631] R.T. 66 (CPSD/Harpster).

[632] *See Application of Pacific Gas and Electric Company, etc.,* D.97-08-055, 1997 Cal. PUC LEXIS 763 (Ex. PG&E-15); *Application of Pacific Gas and Electric Company, etc.,* D.02-08-070, 2002 Cal. PUC LEXIS 518 (Ex. PG&E-17); *Application of Pacific Gas and Electric Company, etc.,* D.04-12-050, 2004 Cal PUC Lexis 579 (Ex. PG&E-23); *Application of Pacific Gas and Electric Company, etc.,* D.07-09-045, 2007 Cal. PUC LEXIS 449 (Ex. PG&E-27).

[633] Ex. PG&E-10, MPO-3 at 1-2 (PG&E/O'Loughlin); Ex. PG&E-10, MPO-4 at 2 (PG&E/O'Loughlin); R.T. 86-87 (CPSD/Harpster); Ex. PG&E-13; Ex. PG&E-14.

[634] Ex. PG&E-10, MPO-1 at 27-29 (PG&E/O'Loughlin); Ex. PG&E -10, MPO-3 at 6-7 (PG&E/O'Loughlin); Ex. CPSD-168 at 2-7 (CPSD/Harpster); R.T. 105 (CPSD/Harpster); Ex. PG&E-16.

[635] Ex. PG&E-10, MPO-3 at 8 (PG&E/O'Loughlin); Ex. PG&E -10, MPO-4 at 7 (PG&E/O'Loughlin); Ex. CPSD-168 at 2-7 (CPSD/Harpster); R.T. 116-18 (CPSD/Harpster); Ex. PG&E-19.

[636] Ex. PG&E-10, MPO-4 at 9 (PG&E/O'Loughlin); Ex. CPSD-168 at 2-7 (CPSD/Harpster); Ex. CPSD-170 at 55 (CPSD/Harpster); R.T. 124-26, 133 (CPSD/Harpster); Ex. PG&E-20; Ex. PG&E-21.

Accord III settlement). The settlement does not, however, explicitly set out the O&M and capex amounts that were used to develop the settlement revenue requirements or rates.[637]

The lack of detailed cost of service information in the settlements covering 13 of the 14 years at issue has several important – and undisputed – implications. Determining the imputed adopted O&M and capex amounts in many of those years involves a considerable amount of judgment.[638] Because the settlements do not provide details about the adopted cost of service forecasts, assumptions must be made to estimate the O&M and capex amounts implicit in revenue requirements and rates. For many of the years, there is more than one potentially reasonable method for estimating the imputed adopted O&M and capex amounts.[639] There is therefore no one "correct" imputed adopted amount for the entire period analyzed by Overland,[640] but rather a range of possible reasonable estimates of the imputed adopted amounts.[641]

Consistent with the fact that there is not one clearly correct imputed adopted amount for a given year, estimating the imputed adopted amounts is complex and time-consuming. The parties to the settlements do not appear to have contemplated that anyone would engage in a backward-looking exercise to compare PG&E's actual expenditures to the imputed adopted O&M and capex amounts in the settlement revenue requirements and rates – otherwise they would have explicitly documented these amounts in the settlements.[642] Messrs. Harpster and O'Loughlin agree this is a fairly unique exercise.[643] Furthermore, this type of *ex post* comparison is arguably at odds with the principles underlying forward test-year ratemaking. *See, e.g.*, *Application of Pacific Gas & Electric Company*, *etc.*, D.96-12-066, 1996 Cal. PUC LEXIS 1111, at *4-*5 (quoting D.85-03-037, 1985 Cal. PUC LEXIS 104; 17 CPUC 2d 246, 254) ("Ratemaking . . . is essentially the art of estimating future events based on judgment that is as

[637] Ex. PG&E-10, MPO-1 at 31-32 (PG&E/O'Loughlin); Ex. PG&E-10, MPO-3 at 12 (PG&E/O'Loughlin); Ex. PG&E-10, MPO-4 at 13 (PG&E/O'Loughlin); Ex. CPSD-168 at 2-7 to 2-8 (CPSD/Harpster); R.T. 161 (CPSD/Harpster); Ex. PG&E-26.

[638] R.T. 57-58, 61-62 (CPSD/Harpster); PG&E-10, MPO-1 at 12-13 (PG&E/O'Loughlin).

[639] R.T. 62 (CPSD/Harpster).

[640] R.T. 63 (CPSD/Harpster).

[641] R.T. 561 (PG&E/O'Loughlin).

[642] R.T. 69 (CPSD/Harpster); R.T. 544 (PG&E/O'Loughlin).

[643] R.T. 544 (PG&E/O'Loughlin); R.T. 63 (CPSD/Harpster).

fully informed as possible. We know in prospective test year ratemaking that our adopted estimates of revenues and expenses may be at variance with actual hindsight experience.").

b. Mr. Harpster's And Mr. O'Loughlin's Results Compared

Although Overland's task was to compare PG&E's "actual gas transmission *safety-related* O&M expenses and capital expenditures to the levels included in rates,"[644] as discussed further in Section V.F.1.d.(i) below, Overland did not perform an analysis focusing on only safety-related O&M expenses and did so for capital expenditures only for 2003 to 2010. For that period, Overland found that PG&E spent $35 million *more* than the safety-related capital expenditures implicit in rates.[645] Overland also conducted an analysis for both O&M and capital that was not focused specifically on safety-related costs. As part of that analysis, Overland initially found that PG&E spent $39.2 million less than the imputed adopted amounts for O&M expenses and $95.4 million less than the imputed adopted amounts for capital expenditures from 1997 to 2010.[646] CPSD imported these findings into its separate report,[647] where it recommends that PG&E be required to "use these previously authorized ratepayer funds" before seeking "additional ratepayer funds going forward."[648] In his rebuttal testimony, Mr. Harpster revised his findings based on his review of Mr. O'Loughlin's testimony.[649] Mr. Harpster claimed that PG&E spent $39.9 million less than the imputed adopted O&M amounts and $116.7 million less than the imputed adopted capital expenditures from 1997 to 2010.[650] Mr. Harpster did not update his safety-focused capex comparison.[651]

Mr. O'Loughlin also was not able to conduct a solely safety-focused comparison for O&M and could do so for capital only for 2004 to 2010. He found that PG&E spent $63.2 million more on safety-related capex than the imputed adopted amounts in those years.[652] Like

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[644] Ex. CPSD-168 at 1-2 (CPSD/Harpster) (emphasis added); R.T. 56-57 (CPSD/Harpster).

[645] Ex. CPSD-168 at 4-3 (CPSD/Harpster).

[646] Ex. CPSD-168 at 3-2 (Table 3-1) (CPSD/Harpster);*id*. at 4-2 (Table 4-1).

[647] In its Recommendation 31, CPSD relies on Overland's closely related finding that PG&E spent $39.3 million less than the imputed adopted amounts for transmission-related O&M expenses. *See* Ex. CPSD-168 at 3-3 (Table 3-2) (CPSD/Harpster).

[648] Ex. CPSD-1 at 168 (Recommendations 31 and 32) (CPSD/Stepanian).

[649] Ex. CPSD-170 at 6-8 (CPSD/Harpster).

[650] Ex. CPSD-170 at 7-8 (Tables 3-2 and 3-3) (CPSD/Harpster).

[651] R.T. 78 (CPSD/Harpster).

[652] Ex. PG&E-10, MPO-1 at 46-47 (PG&E/O'Loughlin).

Overland, he also conducted a broader analysis of imputed adopted O&M and capex compared to PG&E's actual expenditures, but with different results. Mr. O'Loughlin found that PG&E spent $43.1 million more than the imputed adopted O&M amounts and $261.5 million more than the imputed adopted capex amounts from 1997 to 2010.[653]

The following chart summarizes Messrs. Harpster's and O'Loughlin's comparisons of the imputed adopted amounts to PG&E's actual expenditures (parenthes es indicated claimed underspending) (dollars in millions):

	Overland/Harpster	O'Loughlin
O&M Expenses (1997-2010)	($39.9)	$43.1
All Capital Expenditures (1997-2010)	($116.7)	$261.5
Safety-Related Capital Expenditures	$35 (2003-2010)	$63.2 (2004-2010)

The fact that there is a range of potentially reasonable imputed adopted amounts for many of the years does not mean that *any* estimate of the imputed adopted O&M and capex amounts is necessarily reasonable. Rather than closely follow the terms of the GT&S rate case settlements, Mr. Harpster chose to give precedence to his own views about how rate cases should work. As a result, and as discussed further in the next section, his calculated imputed adopted amounts are inherently unreliable and should not be compared to PG&E's actual expenditures.

c. Mr. Harpster's Estimates Of The Imputed Adopted Amounts Are Unreliable And Cannot Support The Conclusion That PG&E Spent Less Than The Imputed Adopted Amounts

(i) Mr. Harpster Did Not Adhere To The Terms Of The Parties' Settlements And The Commission Decisions Approving Those Settlements

Mr. Harpster substituted his own unsupported assumptions about what the parties or the Commission *should have done* – what he calls "sound cost of service principles"[654] – for what they actually did. His imputed adopted amounts are untethered from the settlement terms and

[653] Ex. PG&E-10, MPO-1 at 19, 43 (PG&E/O'Loughlin).

[654] *See, e.g.*, R.T. 67, 91 (CPSD/Harpster); Ex. CPSD-170 at 26, 36 (CPSD/Harpster).

instead are based on a variety of different sources including forecasts created long after the Commission decisions setting rates for the years in question. Mr. Harpster's results-oriented approach renders his conclusions unreliable as estimates of the O&M and capex amounts implicit in the GT&S revenue requirements and rates.

One of the principal flaws in Mr. Harpster's analysis is that he frequently disregards the settlement terms and goes outside the settlement documents themselves to use data from forecasts that the parties and the Commission never saw – and never could have seen – before they agreed to and approved the rates for a given rate case period.[655] In some cases, Mr. Harpster relies on forecasts that were created *years* after the Commission set the rates for the period in question.[656] His use of *ex post* data to estimate the imputed adopted amounts is contrary to the entire purpose of the exercise – to determine the O&M and capex amounts implicit in the settlement revenue requirements and rates approved by the Commission.[657] Indeed, Mr. Harpster concedes – as he must – that in certain years his imputed adopted amounts were not the amounts in rates during the years at issue.[658] For example, with respect to his imputed adopted capex amount for 2007, he urged:

> As I stated this morning, I want to make sure everybody is clear. I'm not trying to say that that 2007 forecast from the GA 4 case was literally in rates starting in January of 2007. It wasn't.[659]

This alone makes Mr. Harpster's estimates of the imputed adopted O&M and capex amounts invalid.

Mr. Harpster tries to justify his reliance on forecasts that did not form the basis for the settlement revenue requirements and rates on the ground that, whether or not the parties explicitly adopted a settlement forecast, in his view, "sound cost of service principles" warrant basing the imputed adopted amounts on detailed cost of service forecasts, even if those forecasts were created years after rates were set.[660] While Mr. O'Loughlin used detailed forecasts to estimate his imputed adopted amounts *if those forecasts were part of the settlement materials*

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[655] *See, e.g.*, R.T. 110 (CPSD/Harpster).

[656] R.T. 141-42, 144, 174 (CPSD/Harpster).

[657] Ex. PG&E-10, MPO-1 at 34 (PG&E/O'Loughlin).

[658] R.T. 71, 138, 145-46, 172 (CPSD/Harpster).

[659] R.T. 146 (CPSD/Harpster); *see also* R.T. 145 (CPSD/Harpster).

[660] *See, e.g.*, Ex. CPSD-170 at 51-52, 57-58, 61, 64-65, 70-71 (CPSD/Harpster); *see also* R.T. 67 (CPSD/Harpster) (discussing application of "sound cost of service principles" in determining imputed adopted amounts).

and were used to set the settlement revenue requirements and rates, Mr. Harpster contends that the parties and the Commission must have considered detailed cost of service information before approving any settlement *even where there is no evidence they did so*.[661] This position is at odds with the fact that the Commission approved the four GT&S rate case settlements based on a variety factors having little or nothing to do with PG&E's cost of service and notwithstanding the lack of detailed cost of service information in the settlement materials for many of the years.[662] Yet, the Commission has recognized that a lack of detailed cost of service information in a settlement is not "an insurmountable problem, given the fact that under forecast test year ratemaking a utility is generally neither obligated to spend the authorized amount nor limited to spending only the authorized amount."[663]

Mr. Harpster's imputed adopted amounts are also unreliable because he changed his method for determining the imputed amounts from rate case to rate case and even within individual rate cases.[664] Mr. Harpster's method changes almost always led to him increasing the imputed adopted amount (and therefore also adding to the amount of PG&E's alleged underspending). For example, Mr. Harpster used a different source for his imputed adopted capex amount for 2007 than he used for O&M for the same year because, in his view, if he had used a consistent method, his imputed adopted capex amount would have been too low.[665] He did this even though he admits that his imputed adopted capex amount for 2007 was approximately $38 million more than the amount actually in rates in 2007.[666] Similarly, rather than use the same forecast for all of the Gas Accord IV period, he used a much later forecast for capital (but not O&M) in 2010 only so that he could increase his imputed adopted capex amount in that year:

> Q: [I]f you had used [the same] forecast for your imputed adopted [2010 capex] amount, the amount would have been too low, right? That's basically what you're saying?

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[661] R.T. 112 (CPSD/Harpster) ("when a commission approves a settlement that's setting rates for a year, they have some sense of what return on equity or profitability level is going to be produced by that settlement").

[662] Ex. PG&E-15 at 19-26 (Commission decision discussing reasonableness of settlement); Ex. PG&E-17 at 11- 19 (same); Ex. PG&E-23 at 11-12 (same); Ex. PG&E-27 at 13-16 (same).

[663] *Application of Pacific Gas and Electric Company*, D.04-05-055, 2004 Cal. PUC Lexis 254, at *115; *Application of Southern California Gas Company*, D.04-12-015, 2004 Cal. PUC LEXIS 574, at *73 (same).

[664] Ex. CPSD-168 at 2-8 & Table 2-3 (chart summarizing his methods) (CPSD/Harpster).

[665] Ex. CPSD-170 at 58 (CPSD/Harpster); R.T. 139 (CPSD/Harpster).

[666] R.T. 138-41, 144-45 (CPSD/Harpster).

A: Yes, that's basically what I'm saying. . . .[667]

In contrast, Mr. O'Loughlin carefully applied the terms of the settlement agreements and other settlement materials to determine his imputed adopted O&M and capex amounts.[668] Mr. O'Loughlin tried to estimate, as closely as possible, the O&M and capex amounts implicit in the settlement revenue requirements, just as in a fully litigated case the adopted O&M and capex amounts would be used to calculate a revenue requirement that in turn would be used to set rates.[669] That is, he approximated how the Commission would address the issue in a fully litigated rate case, and he only relied on data that the Commission had when it approved the settlements in question.[670]

Mr. O'Loughlin explained the rationale for his approach as follows:

> [T]he parties reached a settlement which typically specified settlement revenue requirements and often underlying those settlement revenue requirements gave you information about the O&M that was implicit in the settlement revenue requirements or gave you information that would allow you to derive the capex that was implicit in those settlement revenue requirements. And then the Commission reviewed both the settlements and underlying support materials for the adjustments and reasonableness of what was in those settlements and was fully cognizant [of] the revenue requirements that were agreed to in the settlements, and then the Commission approved the settlements. So to me, that's about as close as you're going to get to the equivalent of an adopted revenue requirement that the Commission would produce in an adjudicated proceeding.[671]

He also elaborated on the critical difference between his approach and Mr. Harpster's:

> As I said, this is a relatively unique exercise. It's complicated. It takes judgment. And the judgment that I think it takes involves interpreting the settlements and the workpapers and trying to get the numbers that are in the settlement revenue requirements. And believe me, doing that alone is not trivial. But I think Mr. Harpster believes that you can go beyond that in te rms of judgment. He's willing to say at times: Gee, you know what, the settlement revenue requirement's just not relevant; the O&M number or the

[667] R.T. 171 (CPSD/Harpster).
[668] Ex. PG&E-10, MPO-1 at 13 (PG&E/O'Loughlin).
[669] R.T. 558-59, 561-62 (PG&E/O'Loughlin).
[670] Ex. PG&E-10, MPO-1 at 16-17 (PG&E/O'Loughlin).
[671] R.T. 558-59 (PG&E/O'Loughlin).

> capex numbers that's implicit in that, just not relevant; I'm going to use something else, and it could be from a document that was prepared two or three years later after the settlement occurred. So I think he has a very expansive view as to what judgment can be applied to come up with imputed adopted amounts.[672]

Consistent with this fundamental difference in their respective approaches, Mr. Harpster even criticized Mr. O'Loughlin for following the settlements *too closely*, arguing that certain settlement documents should be ignored as "superfluous."[673]

(ii) Mr. Harpster Made Many Specific Errors That Render His Overall Conclusions Invalid And Unreliable

(a) Mr. Harpster Deviated From The Settlement Terms In Calculating His Imputed Adopted O&M Expenses For The Gas Accord I Period

Overland's imputed O&M amount for the very first year of Gas Accord I contradicts the terms of the settlement agreement and the detailed escalation calculations in the accompanying workpapers. The Gas Accord I settlement agreement explicitly states that "[i]nitial base revenue requirements for calculating 1997 rates match PG&E's 1996 GRC."[674] In other words, there was no escalation of the revenue requirement from the base year 1996 to 1997, the first year of Gas Accord I.[675] The settlement also provides that transmission rates would escalate by 2.5% per year from 1998 through 2002.[676] In addition to the settlement agreement itself, the parties agreed to the terms reflected in the supporting workpapers, which they provided to the Commission when they sought approval for the settlement.[677] The settlement workpapers specify how the escalation would work. The workpapers show that none of the individual revenue requirement elements – including O&M expenses – were escalated from 1996 to 1997 and that each revenue

[672] R.T. 560-61 (PG&E/O'Loughlin).

[673] Ex. CPSD-170 at 29 (CPSD/Harpster) (arguing that the Gas Accord I settlement workpapers should not be followed because they were "superfluous and contrary to sound cost-of-service principles"); *id.* at 56-57 (criticizing Mr. O'Loughlin for relying on the Gas Accord III settlement workpapers, portions of which he characterizes as "superfluous").

[674] Ex. PG&E-13 at 38.

[675] R.T. 88 (CPSD/Harpster); Ex. CPSD-168 at 2-9 (CPSD/Harpster).

[676] Ex. PG&E-15 at 18.

[677] R.T. 88, 91-92 (CPSD/Harpster).

requirement element was escalated 2.5% per year thereafter (i.e., in 1998 through 2002). [678] Mr. Harpster concedes, "that's the way the schedule works."[679]

Mr. Harpster nonetheless chose to escalate the 1996 base year O&M amount by 2.5% in 1997. He initially tried to justify disregarding the terms of the settlement by explaining that, in his view, "[a]dop ted O&M should reflect realistic expectations rather than negotiated concessions that may have been influenced by unrelated issues."[680] Perhaps realizing that he had conceded his imputed adopted amount directly contradicted the settlement terms, [681] Mr. Harpster switched to defending his approach on the ground that the settlement workpapers are "superfluous and contrary to sound cost of services principles."[682] In other words, he substituted his own views about what is "sound" for what the parties actually did. In contrast, Mr. O'Loughlin used the adopted O&M amount from the 1996 GRC without escalation for his imputed adopted 1997 amount to be consistent with the settlement agreement and the settlement workpapers.[683] He then increased that amount by 2.5% each year from 1998 through 2002.[684]

(b) Mr. Harpster Significantly Overstates The Imputed Adopted Amounts For The 2003 Rate Case

To calculate O&M and capex amounts in the 2003 rate case, Mr. Harpster once again deviates from the terms of the settlement agreement and instead relies on a forecast created after the Commission's decision setting rates for 2003. The 2003 GT&S rate case settlement is straightforward: the parties agreed that the 2002 rates would remain in place for an additional year during 2003.[685] Not only were rates extended for an additional year without any increase, the entire "existing market structure, rates, tariffs, and terms and conditions of service for the PG&E gas transmission and storage system, as adopted in the Gas Accord" were extended. [686]

[678] R.T. 89-91 (CPSD/Harpster); Ex. PG&E-14 at 98, 100, 115, 127, 139, 151, 163.

[679] R.T. 90-91 (CPSD/Harpster).

[680] Ex. CPSD-168 at 2-9 (CPSD/Harpster).

[681] Although Mr. Harpster tried to retract a portion of the sentence quoted above during cross-examination, he agreed that "part of the negotiation was . . . not to have an escalation applied in 1997." R.T. 95 (CPSD/Harpster).

[682] Ex. CPSD-170 at 29 (CPSD/Harpster); R.T. 90-91 (CPSD/Harpster).

[683] Ex. PG&E-10, MPO-3 at 1 (PG&E/O'Loughlin).

[684] Ex. PG&E-10, MPO-3 at 2-3 (PG&E/O'Loughlin).

[685] Ex. PG&E-16 at 2; R.T. 104 (CPSD/Harpster); Ex. PG&E-17 at 20 (Finding of Fact 5).

[686] Ex. PG&E-16 at 2.

PG&E did not provide any cost of service information as part of the 2003 settlement, and there is no adopted revenue requirement in the settlement agreement or decision.[687]

In light of the settlement terms and the lack of cost of service information in the 2003 settlement materials, Mr. O'Loughlin used the same imputed adopted O&M amount for 2003 as for 2002.[688] For capital, he determined the amount of capital expenditures for 2003 needed to maintain the same rate base and revenue requirement as in 2002.[689] Mr. Harpster, however, chose to base his imputed adopted amounts on a forecast pulled from the next rate case proceeding (the 2004 rate case) that was prepared months after the decision setting rates for 2003, and that the parties and the Commission did not have when they approved the settlement.[690] To justify this approach, Mr. Harpster insists – based on nothing but his own *ipse dixit* – that the parties' and Commission's decisions to "agree upon and approve the rates established by the GA II settlement were based on the decision makers' perceptions of the current (2003) cost of providing service," and that the forecast from the 2004 rate case was the best proxy for that understanding.[691]

Not only is there no support for the second point, Mr. Harpster's threshold premise that the Commission and the parties *must* have considered PG&E's cost of service before approving the settlement is contradicted by the Commission's decision rejecting a party's request that the Commission review cost of service information prior to approving the rates for 2003.[692] This is yet another instance where Mr. Harpster imposes his own views about what the parties and the Commission should have done – his "sound cost of service principles" – notwithstanding record evidence showing that they did something different.

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[687] R.T. 66, 105 (CPSD/Harpster).

[688] Ex. PG&E-10, MPO-3 at 7 (PG&E/O'Loughlin).

[689] Ex. PG&E-10, MPO-4 at 6-7 (PG&E/O'Loughlin).

[690] R.T. 110 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 31 (Figure 7) (PG&E/O'Loughlin).

[691] Ex. CPSD-170 at 42 (CPSD/Harpster); Ex. CPSD-168 at 2-9 (CPSD/Harpster).

[692] Ex. PG&E-17 at 18. Even when asked about the fact that the Commission itself stated that the parties and the Commission did not have current cost of service information, Mr. Harpster still clung to his view that the Commission must have had some cost of service information when it approved the 2003 rate case settlement. *See* R.T. 112 (CPSD/Harpster) ("They may not have had much detailed cost information, but it's just not plausible to say that they went back to the 1996 GRC as the basis for their determination that the settlement was reasonable.").

(c) Mr. Harpster Used An Inflated 2007 Imputed Adopted Capex Amount That He Admits Was Not In Rates In 2007

In estimating the 2007 imputed adopted capex amount, Mr. Harpster again disregards the terms of the settlement. Instead, he relies on a forecast created years after the Commission's decision setting rates for 2007 to derive an imputed adopted amount that he concedes was not in rates in 2007. The Gas Accord III settlement agreement, which set rates for 2005 through 2007, included detailed cost of service information for 2005 only.[693] For 2006 and 2007, the agreement provided that the "total revenue requirement escalates at two (2) percent for 2006 and 2007, except for the revenue requirement attributable to the G-XF contracts."[694] As explained in the comparison matrix provided to the Commission to show the difference between the parties' litigation and settlement positions, the revenue requirement escalation rates also applied to O&M expenses and capital expenditures.[695]

As Mr. Harpster testified, when a settlement agreement includes a settlement revenue requirement, that revenue requirement is typically used to calculate the settlement rates in much the same way as in a fully litigated case.[696] And, where there is an explicit settlement revenue requirement, there is usually a direct, mathematical relationship between the settlement revenue requirement and the adopted rates.[697] For that reason, the imputed adopted O&M and capex amounts should be directly connected to the settlement revenue requirement. Mr. O'Loughlin followed this principle in calculating his imputed adopted O&M and capex amounts for the Gas Accord III period. For his 2006 and 2007 imputed adopted O&M amounts, he increased the 2005 amount by the escalation rates in the settlement agreement.[698] For capex, he estimated the amounts that would be consistent with the settlement revenue requirements and rate base escalation for 2006 and 2007.[699] Mr. Harpster also followed this principle for O&M expenses:

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[693] R.T. 133 (CPSD/Harpster); Ex. CPSD-170 at 55 (CPSD/Harpster).

[694] The overall escalation rate was approximately 1.89% after accounting for the portion of the revenue requirement attributable to G-XF contracts. R.T. 133-34 (CPSD/Harpster); Ex. PG&E-21 at 7.

[695] Ex. PG&E-20 at 5, 7.

[696] R.T. 74-75 (CPSD/Harpster).

[697] R.T. 73-75 (CPSD/Harpster).

[698] Ex. PG&E-10, MPO-3 at 11 (PG&E/O'Loughlin).

[699] Ex. PG&E-10, MPO-4 at 9-13 (PG&E/O'Loughlin).

he escalated the 2005 imputed adopted amount by 1.89% in 2006 and again by 1.89% in 2007.[700] He also did something similar (albeit a rough simplification) for capital in 2006: he estimated the imputed adopted amount by escalating his 2005 amount by 1.89%.[701] However, he chose an entirely different method for estimating the imputed adopted capex amount for 2007, even though nothing in the Gas Accord III settlement supports doing so.[702]

For his 2007 imputed adopted capex amount, Mr. Harpster used a forecast from the next rate case proceeding that was created approximately 2-1/2 years after the parties reached the settlement and two years after the Commission issued its decision setting rates for 2005 through 2007.[703] The parties obviously did not have the Gas Accord IV forecast when they agreed on 2007 rates in the Gas Accord III settlement.[704] Mr. Harpster acknowledges that his 2007 imputed adopted capex amount does not correspond to the amount included in rates in 2007. He explained, "I'm not saying that that amount was the basis for the rates literally charged to customers in 2007. It wasn't."[705] And he agrees that an imputed adopted capex amount for 2007 calculated by increasing the 2006 amount by 1.89% would be a "fair approximation" of the amount actually included in rates in 2007.[706] But instead of using that amount – which he characterizes as "substantially lower" than the forecast he used[707] – Mr. Harpster increased the 2006 imputed adopted amount by 35% ($37.5 million) even though the settlement agreement expressly states that rates and the revenue requirement would increase only by 2% (not counting the G-XF contracts).

Mr. Harpster attempts to justify using the 2007 forecast from the next rate case on the ground that it was the "only available detailed forecast for 2007."[708] But if the parties or the Commission had felt that it was important to have a detailed capital forecast for 2007 when they

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[700] Mr. Harpster originally escalated the imputed adopted O&M amounts by 2% (*see*Ex. CPSD-170 at 2-8 (Table 2-3) (CPSD/Harpster)); however, in his rebuttal testimony he revised his calculations to use the same rate as Mr. O'Loughlin to take into account the G -XF contracts. Ex. CPSD-170 at 7 (CPSD/Harpster); Ex. CPSD-168 at 2-8 (Table 2-3) (CPSD/Harpster); R.T. 133 (CPSD/Harpster).

[701] R.T. 134 (CPSD/Harpster).

[702] R.T. 138 (CPSD/Harpster).

[703] Ex. PG&E-10, MPO-1 at 52-53 & Figure 14 (PG&E/O'Loughlin).

[704] R.T. 144 (CPSD/Harpster); *see also* R.T. 141-42 (CPSD/Harpster).

[705] R.T. 71 (CPSD/Harpster).

[706] R.T. 144-45 (CPSD/Harpster).

[707] R.T. 139, 141 (CPSD/Harpster).

[708] Ex. CPSD-170 at 57-58 (CPSD/Harpster).

approved the rates for that year, they would have said so.[709] What is more, Mr. Harpster did not consistently follow his own rule. The same forecast that he used for his 2007 imputed adopted capex amount also includes forecasts for 2006 capital and 2006 and 2007 O&M.[710] But Mr. Harpster did not use *those* detailed forecasts for his imputed adopted amounts. The obvious explanation for this inconsistency – which Mr. Harpster's testimony supports – is that he changed methods for his 2007 imputed adopted capex amount because he did not want to use an amount that would have shown that PG&E spent much more than the capex in rates for that year.[711]

(d) Mr. Harpster Significantly Overstates The Imputed Adopted O&M And Capex Amounts For The Gas Accord IV Period

Mr. Harpster's imputed adopted O&M and capex amounts for the Gas Accord IV period (2008-2010) are inconsistent with the terms of the settlement and do not reflect the amounts actually in rates. The Gas Accord IV settlement explicitly sets forth the adopted revenue requirements for each year, but it does not include detailed cost of service information underlying those revenue requirements.[712] The intent of the Gas Accord IV settlement was to maintain the overall Gas Accord III structure with minimal changes[713] and "to develop rates over the Settlement period based on the 2007 Gas Accord III rates already approved by the Commission."[714] Thus, the 2008-2010 rates and revenue requirements were set based on the 2007 amounts (from the Gas Accord III settlement), with relatively small increases from year to year.[715] The parties reached this settlement before PG&E filed its application and cost of service testimony.[716] To assist the Commission in assessing the reasonableness of the settlement, however, PG&E provided a "litigation forecast," which represented the cost of service forecast

[709] In approving the Gas Accord III settlement, the Commission found that "there is a comprehensive record available to evaluate the settlement and we find that there is no issue that requires any additional record." Ex. PG&E-23 at 12.

[710] Ex. PG&E-24.

[711] R.T. 144-46 (CPSD/Harpster).

[712] Ex. PG&E-26 at 6 & Appendix A, Appendix B.

[713] Ex. PG&E-25 at 1; Ex. PG&E-27 at 5; R.T. 147-48 (CPSD/Harpster); *see also* R.T. 153 (CPSD/Harpster).

[714] Ex. PG&E-25 at 14.

[715] The 2007 revenue requirement was increased by 0.6% in 2008, an additional 2.8% in 2009, and an additional 2.7% in 2010. Ex. PG&E-26 at A-3; Ex. PG&E-10, MPO-3 at 12 (PG&E/O'Loughlin); Ex. PG&E-25 at 14.

[716] Ex. CPSD-168 at 2-7 (CPSD/Harpster).

that it would have filed if the case had been litigated, i.e., prior to any negotiated concessions.[717] Even the Commission recognized that PG&E settled the Gas Accord IV case for substantially lower revenue requirements and rates than its "litigation position."[718]

Estimating the imputed adopted amounts for Gas Accord IV is challenging because of the lack of detailed cost of service information in the settlement agreement. Mr. O'Loughlin nonetheless followed a consistent approach for Gas Accord IV as in other settlement periods by estimating the imputed adopted amounts that most closely correspond to the settlement revenue requirements.[719] For O&M, he escalated the 2007 imputed adopted O&M amount in 2008 through 2010 by the overall revenue requirement escalation factors set forth in the Gas Accord IV settlement.[720] For capital, Mr. O'Loughlin also estimated the amounts that most closely would give effect to the revenue requirement escalation in the settlement.[721] While there is not necessarily one correct method to estimating the imputed adopted amounts for this rate case period,[722] Mr. Harpster's approach is unreasonable on its face. *First*, he uses the O&M and capital amounts in PG&E's "litigation forecast" even though those amounts were much higher than the amounts included in rates because they did not reflect any of the concessions PG&E made during the settlement process. *Second*, for the 2010 capex amount, Mr. Harpster uses a forecast created years later for the Gas Accord V rate case that is even higher than PG&E's litigation forecast for 2010.

Mr. Harpster's imputed adopted O&M amounts for 2008 to 2010 and capex amounts for 2008 and 2009 are based on PG&E's litigation forecast.[723] Yet the Commission explicitly stated in its decision setting rates for 2008 to 2010 that the Gas Accord IV settlement rates and revenue requirements were "**much lower** for all three years" than PG&E's litigation position forecast.[724] The parties to Gas Accord IV settlement also recognized that the adopted rates would have been significantly higher if PG&E's litigation forecast had been incorporated into the settlement

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717 Ex. PG&E-25 at 3.
718 Ex. PG&E-27 at 26 (Finding of Fact 11).
719 Ex. PG&E-10, MPO-1 at 56-57 (PG&E/O'Loughlin).
720 Ex. PG&E-10, MPO-3 at 12 (PG&E/O'Loughlin).
721 Ex. PG&E-10, MPO-4 at 13 (PG&E/O'Loughlin).
722 R.T. 161 (CPSD/Harpster).
723 Ex. CPSD-168 at 2-8 (Table 2-3) (CPSD/Harpster).
724 Ex. PG&E-27 at 26 (Finding of Fact 11) (emphasis added).

rates.[725] As the Overland Report itself shows, the settlement revenue requirement was $11 million less than the litigation forecast revenue requirement in 2008, $25 million less in 2009, and $39 million less in 2010. [726] And Mr. Harpster concedes that PG&E's litigation position O&M and capex forecasts corresponded to higher rates than the parties agreed to in the settlement.[727] In fact, there is nothing unusual about the Commission approving a revenue requirement that is lower than PG&E's litigation position. That happened in the 2004 rate case, for example.[728] It happened again in the Gas Accord III settlement for 2005.[729] What is unusual, however, is using the higher litigation position forecast to determine the imputed adopted amounts. Mr. Harpster himself did not do that for either 2004 or 2005, but rather used amounts consistent with the Commission's decision in 2004 and the Gas Accord III settlement revenue requirement in 2005 – both of which were lower than PG&E's litigation position in those years.[730]

As in prior rate case periods, Mr. Harpster tries to justify not basing his Gas Accord IV imputed adopted amounts on the settlement revenue requirements and rates on the ground that the litigation position forecasts are the only available detailed forecasts. [731] But that argument cannot support using imputed adopted amounts that do not correspond to the amounts in rates. Mr. Harpster also contends that it was appropriate to use the litigation position forecasts because (1) an internal PG&E forecast shows that the company anticipated sufficient GT&S revenues to cover the higher litigation position revenue requirement and (2) actual revenues turned out to be sufficiently high to cover the litigation position revenue requirement. [732] But these arguments turn the exercise of determining the imputed adopted amounts implicit in revenue requirements and rates on its head. PG&E's internal forecast may or may not have turned out to be accurate and, in any event, *it was not the basis for calculating the rates set by the Commission's decision*. Mr. Harpster's reliance on what actual revenues turned out to be is circular, and does not change the fact that his imputed adopted amounts were not in rates. In fact, he agrees that if the

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[725] Ex. PG&E-11, MPO-19 at 3.

[726] Ex. CPSD-168 at 2-10 (Table 2-4) (CPSD/Harpster); R.T. 160-61 (CPSD/Harpster).

[727] R.T. 168-69 (CPSD/Harpster).

[728] Ex. PG&E-19 at 205-08, 216-22.

[729] Ex. PG&E-20 at 4, 5, 7.

[730] R.T. 117-18, 119-20, 124, 126 (CPSD/Harpster).

[731] Ex. CPSD-168 at 2-11 (CPSD/Harpster); R.T. 145-46 (CPSD/Harpster).

[732] Ex. CPSD-168 at 2-11 (CPSD/Harpster); R.T. 162-64 (CPSD/Harpster).

litigation forecast had been used to calculate rates, the rates would have been significantly higher.[733]

To make matters worse, Mr. Harpster took yet another approach to determine his imputed adopted capex amount for 2010. He did not use the litigation forecast amount but instead a much higher forecast for 2010 from the Gas Accord V proceeding. [734] The litigation position forecast that he used for his other imputed adopted amounts for 2008 to 2010 – although it significantly overstates the correct imputed adopted amounts – was at least a forecast that the Commission received prior to approving the settlement rates. The forecast from the next rate case used by Mr. Harpster for his 2010 imputed adopted capex amount, on the other hand, was created in March 2010 – years after the settlement and the Commission's decision setting rates for 2010.[735] Mr. Harpster acknowledges that the 2010 forecast for the Gas Accord V proceeding he used to determine his imputed adopted capex amount does not reflect the capex amount actually included in rates in 2010:

> Q: But the Gas Accord 5 forecast that you used for your 2010 adopted, imputed adopted CapX amount, was not in rates for 2010, right?
>
> A: That's correct . . .[736]

Mr. Harpster's sole justification for not consistently using the amounts in PG&E's litigation forecast (which, again, were themselves higher than the amounts in the settlement revenue requirements and rates) is that the 2010 litigation forecast for capital expenditures was, in his view, simply too low. He admits that if the litigation forecast amount had been much higher he "probably would have used that as [his] source." [737] But there is no evidence that any of the parties or the Commission thought that the 2010 forecast was unrealistically low, as Mr. Harpster believes.[738]

Mr. Harpster's principal suppo rt for his contention that the litigation position capex forecast for 2010 was too low is the fact that PG&E actually spent much more in 2010. [739] This

733 R.T. 168-69 (CPSD/Harpster).
734 Ex. CPSD-168 at 2-8 (Table 2-3) (CPSD/Harpster); R.T. 174 (CPSD/Harpster).
735 R.T. 173-75 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 55 (Figure 15) (PG&E/O'Loughlin).
736 R.T. 172 (CPSD/Harpster).
737 R.T. 171 (CPSD/Harpster).
738 R.T. 171 (CPSD/Harpster).
739 Ex. CPSD-168 at 2-11 to 2-12 (CPSD/Harpster); R.T. 179 (CPSD/Harpster).

argument has many flaws. In the first place, his assertion that the litigation position capex forecast for 2010 was "not credible" when compared to PG&E's actual spending is wrong. In fact, PG&E spent only 7% more than the litigation forecast amounts from 2008 to 2010 – hardly a huge difference.[740] Mr. Harpster inappropriately focuses on 2010 in isolation without taking into account how PG&E's spending over the entire rate case period compared to the forecast amounts. His method of taking a forecast for 2009 from one source and a forecast for 2010 from an unrelated source created years later ignores the fact that forecasts change over time and greater capital expenditures in one year might balance out lesser capital expenditures in another year within the same rate case period.[741] Furthermore, there is no point in comparing the imputed adopted amounts to what PG&E actually spent if PG&E's actual expenditures are to be used effectively as a proxy for the imputed adopted amounts. The whole exercise would become circular. The fact that a forecast amount is or is not close to what PG&E actually spent has nothing to do with what amount is included in rates. Indeed, as noted above, Mr. Harpster concedes his imputed adopted 2010 capex amount is not the amount included in rates in 2010.[742]

Finally, Mr. Harpster's picking and choosing different and inconsistent forecasts on which to base his imputed adopted amounts within the same rate case period produces inherently unreliable results. Mr. Harpster selected a different source for 2010 capex because the litigation forecast was, in his view, much too low when compared to PG&E's actual expenditures.[743] But he used the litigation forecast for 2009 capex when PG&E's actual spending was significantly less than the litigation forecast amount.[744] Unless one is trying to bias the outcome, there is no reason to use actual spending as a basis for estimating imputed adopted amounts only when PG&E spends more than a forecast but never when PG&E spends less.[745] In addition, by using forecasts created years apart for different years in the same rate case period, Mr. Harpster's method double-counts the same forecast costs when they were moved from an earlier to a later

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[740] Ex. PG&E-30.

[741] R.T. 183-84 (CPSD/Harpster).

[742] R.T. 172 (CPSD/Harpster).

[743] R.T. 179 (CPSD/Harpster).

[744] Ex. PG&E-30.

[745] In other words, Mr. Harpster's method penalizes PG&E both for spending less than the litigation forecast *and* for spending more (as in 2010), because he uses the higher spending to bootstrap his argument that the original forecast amount should be not be used.

year within the rate case period as the forecast changed over time. [746] For example, his imputed adopted amounts for 2008-2010 include approximately $96 million for the Lines 406 and 407 "adder" projects, even though the total forecast costs for those projects during the Gas Accord IV period was $75 million per the Gas Accord IV litigation forecast capital workpapers, which were Mr. Harpster's source for his 2008 and 2009 imputed adopted amounts.[747]

The differences between Mr. O'Loughlin and Mr. Harpster are particularly pronounced during the Gas Accord IV period. Mr. Harpster argues that Mr. O'Loughlin's imputed adopted capex amounts for 2008-2010 are unreasonably low – a contention that is founded on Mr. Harpster's own refusal to follow the terms of the Gas Accord IV settlement. Mr. O'Loughlin explicitly based his imputed adopted capital amounts on the settlement revenue requirements and rates that the Commission adopted rather than the much higher litigation position forecast that Mr. Harpster used (when he did not go outside the rate case proceeding altogether, as he did for his 2010 capex amount). The large difference between the litigation forecast revenue requirements and the settlement revenue requirements explains the even larger difference between Mr. Harpster's and Mr. O'Loughlin's imputed adopted capex amounts during Gas Accord IV.[748]

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[746] R.T. 183- 84 (CPSD/Harpster). This problem is exacerbated by Mr. Harpster's practice of trying to use the highest forecast amounts in all years regardless of whether they come from forecasts prepared at different points in time.

[747] R.T. 191-93 (CPSD/Harpster) (explaining his imputed adopted amounts for these projects); Ex. CPSD-170 at 77 (Table 10-7) (CPSD/Harpster) (showing Gas Accord IV litigation forecast for these projects).

[748] Mr. Harpster incorrectly contends that Mr. O'Loughlin's imputed adopted capex amounts for Gas Accord IV are *prima facie* unreasonable because they imply unprecedented reductions from PG&E's litigation forecast capex amounts. This argument ignores the fact that reductions in revenue requirements usually correspond to much larger reductions in adopted capex amounts because the revenue requirements reflect only the portion of the capital additions that is depreciated in that particular year. *See* R.T. 130 (CPSD/Harpster) (discussing how a $0.7 million reduction in revenue requirement corresponded to a $10 million reduction in capex); R.T. 212-13 (CPSD/Harpster) (explaining "rule of thumb" that a dollar of capex corresponds to a revenue requirement of approximately 12 -13 cents). Thus, it is not surprising that the $75 million reduction from PG&E's litigation forecast to settlement revenue requirements in 2008-2010 (*see* Ex. CPSD-168 at 2-10 (Table 2-4) (CPSD/Harpster)) would lead to still larger differences between the litigation position capital forecast and the imputed adopted capex (without even taking into account Mr. Harpster using a much higher capex forecast for 2010 as discussed above). Mr. Harpster's contention is also belied by the settlement in Gas Accord V, in which a 7% reduction in the revenue requirement from PG&E's litigation position (excluding "adder" projects) explicitly led to a 42% reduction in capex. *See* Ex. PG&E-31; Ex. PG&E-34.

(e) Without These Errors Mr. Harpster Would Have Found Little If Any Underspending On O&M And Significant Overspending On Capital

The errors described above explain the most significant differences between Mr. Harpster and Mr. O'Loughlin and illustrate Mr. Harpster's disregard of the terms of the settlements and the Commission decisions approving the settlements. With respect to Mr. Harpster's O&M comparison, correcting only the mistakes described above, his imputed adopted amounts for 1997 to 2010 would have been approximately $36 million less – representing about 90% of the $40 million in underspending he claimed.[749] In other words, he would have claimed about $4 million in underspending over a 14 year period or less than $300,000 per year.[750] With respect to capex, correcting the errors described above, he would have found that PG&E spent approximately $272 million *more* than the imputed adopted amounts rather than $117 million less.[751] Thus, to the extent CPSD bases any purported violation or recommended penalty on a claim that PG&E spent less than the imputed adopted amounts, CPSD has failed to satisfy its burden of proof.

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[749] The Gas Accord I error discussed above in Section V.F.1.c.(ii)(a) caused Mr. Harpster to overstate his imputed adopted amounts by $8.7 million. Ex. PG&E-10, MPO-1 at 26 (PG&E/O'Loughlin); Ex. CPSD-170 at 31 (CPSD/Harpster). The error in 2003 discussed in Section V.F.1.c.(ii)(b) caused Mr. Harpster to overstate his imputed adopted O&M amount for that year by approximately $10 million. R.T. 108 (CPSD/Harpster); Ex. PG&E-18. Mr. Harpster's decision not to use the settlement revenue requirement for his imputed adopted amounts in Gas Accord IV, as discussed in Section V.F.1.c.(ii)(d), led him to overstate the imputed adopted O&M amounts for that period by $17.1 million. Ex. PG&E-10, MPO-1 at 33 (PG&E/O'Loughlin).

[750] The remaining differences between Mr. Harpster's and Mr. O'Loughlin's comparisons of the imputed adopted O&M amounts to actual expenditures reflect additional judgments on Mr. Harpster's part with which PG&E disagrees. For example, Mr. Harpster excluded all customer service-related O&M costs from his analysis even though they were legitimate O&M costs incurred in the operation of the GT&S business. *See* Ex. PG&E-10, MPO-1 at 21-22, 36-38 (PG&E/O'Loughlin).

[751] Mr. Harpster's error in 2003 discussed in Section V.F.1.c.(ii)(b) caused him to overstate the imputed adopted capex amount for that year by $25 million or more. R.T. 107-08 (CPSD/Harpster); Ex. PG&E-18. Mr. Harpster's decision to go outside the settlement for his 2007 imputed adopted capex amount as described in Section V.F.1.c.(ii)(c) caused him to overstate that amount by approximately $37.5 million. R.T. 141 (CPSD/Harpster); Ex. PG&E-22. Mr. Harpster's use of the litigation forecast rather than the settlement for his 2008 and 2009 imputed adopted capex amounts as discussed in Section V.F.1.c.(ii)(d) caused him to overstate those amounts by approximately $224 million. Ex. PG&E-10, MPO-1 at 53 (PG&E/O'Loughlin). His decision to use an entirely different forecast in 2010 led to him overstating his 2010 imputed adopted capex amount by approximately $103 million as compared to the amount implicit in the settlement revenue requirement and rates. Ex. PG&E-10, MPO-1 at 53 (PG&E/O'Loughlin). As noted above, the significant difference between the litigation forecast revenue requirements used by Mr. Harpster and the settlement revenue requirements imply much larger differences between the litigation forecast capex and the imputed adopted capex. *See* n.748, *supra*.

d. Even If Mr. Harpster's O&M And Capex Comparisons Were Valid, There Would Be No Basis For Penalizing PG&E Based On Its Past Spending

(i) CPSD Did Not Prove That PG&E Spent Less Than The Imputed Adopted Amounts For Safety-Related Costs

Even assuming that Mr. Harpster's comparison of PG&E's actual expenditures to the imputed adopted amounts implicit in rates were reasonable – which it is not for the reasons described above – CPSD has not established that PG&E spent less than the imputed adopted amounts for *safety-related* capex or O&M costs. In fact, with respect to capital, Mr. Harpster found that PG&E spent $35 million *more* than the imputed adopted safety-related capex amounts for the only period in which he focused on safety-related costs – 2003 to 2010.[752] Although Mr. Harpster concluded that PG&E spent $117 million less than the imputed adopted capex amounts from 1997 to 2010, his total capex comparison includes substantial non-safety-related costs, such as large capacity projects.[753] Mr. Harpster also admitted that he does not know whether PG&E spent more or less than the imputed adopted safety-related capex during 1997 to 2002.[754] With regard to O&M expenses, Mr. Harpster concluded that PG&E spent $40 million less than the imputed adopted amounts from 1997 to 2010.[755] But, as with capital, this comparison includes substantial non-safety-related costs.[756] Thus, Mr. Harpster's testimony does not establish that PG&E spent less than the imputed adopted amounts for safety-related capex or O&M costs.

(ii) The Commission Cannot Reasonably Draw Any Conclusions From Purported Differences Between PG&E's Actual Spending And The Estimated Imputed Adopted Amounts

Even assuming Mr. Harpster's imputed adopted amounts were within the range of reasonable results, the fact that there is no one correct imputed adopted amount for much of the

[752] Ex. CPSD-168 at 4-3 (CPSD/Harpster). Mr. Harpster later revised his overall capex analysis, but did not update his safety-related capex comparison. He agrees, however, that any change would be immaterial. R.T. 80 (CPSD/Harpster). In comparison, Mr. O'Loughlin estimated that PG&E spent $63 million more than the imputed adopted safety-related capex from 2004 to 2010. Ex. PG&E-10, MPO-1 at 46 (PG&E/O'Loughlin).

[753] R.T. 83 (CPSD/Harpster).

[754] R.T. 82 (CPSD/Harpster). In fact, $95 million of the $117 million in the alleged capex underspending identified by Mr. Harpster occurred between 2003 and 2010 – the same time period during which he found that PG&E spent more than the imputed adopted safety-related capex. *See* Ex. CPSD-170 at 8 (Table 3-3) (CPSD/Harpster).

[755] Ex. CPSD-170 at 7 (Table 3-2) (CPSD/Harpster).

[756] R.T. 83-84 (CPSD/Harpster).

relevant time period means, among other things, that it would be inappropriate for the Commission to base any penalty on inconclusive differences between PG&E's actual spending and estimated imputed adopted amounts calculated long after-the-fact. The Commission's decisions approving the settlements did not provide PG&E with explicit adopted O&M and capex amounts. Messrs. Harpster and O'Loughlin agree that the settling parties did not contemplate that PG&E or anyone else would need to calculate the imputed adopted O&M and capex amounts.[757] Even if PG&E had tried to match its spending precisely to the imputed adopted amounts, its estimates of those amounts would not have matched Mr. Harpster's.

It also would be inappropriate to draw conclusions from relatively small differences[758] between actual spending and imputed adopted amounts given that PG&E's GT&S rate cases used a forward test year approach.[759] Even if there had been explicit adopted amounts, PG&E was permitted – even expected – to adjust its budgets to address the most pressing needs at the time, consistent with operating a safe and reliable system. *See, e.g.*, *Application of Pacific Gas and Electric Company*, D.04-05-055, 2004 Cal. PUC LEXIS 254, at *115 ("under forecast test year ratemaking a utility is generally neither obligated to spend the authorized amount nor limited to spending only the authorized amount"). Furthermore, PG&E was not obligated to spend the amounts it received through GT&S rates solely within the GT&S line of business. Under the Commission's GT&S rate case decisions and general Commission policy, PG&E was permitted to use revenues generated by one line of business for other utility purposes, as PG&E deemed appropriate. PG&E was expected to use its own judgment to allocate available financial resources to the highest priority business needs.

[757] R.T. 69 (CPSD/Harpster); R.T. 544 (PG&E/O'Loughlin).

[758] Even assuming that Mr. Harpster's calculations were correct, by his own account, PG&E spent only 3.9% less than the imputed adopted O&M amounts over a 14–year period. *See* Ex. CPSD-170 at 7 (Table 3-2) (CPSD/Harpster). *See also* R.T. 565 (PG&E/O'Loughlin) ("I would disagree with the characterization that [Mr. Harpster] said they underspent a lot of money. I think he finds a relatively small amount of underspending, frankly.").

[759] Ex. PG&E-10, MPO-1 at 78 (PG&E/O'Loughlin) (explaining that with forward test year regulation it is more likely that actual costs will differ from imputed adopted amounts).

2. CPSD Has Not Proven That PG&E Should Be Penalized For GT&S Earning Returns That Were Permitted And Contemplated By The Gas Accord Structure

Mr. Harpster and Mr. O'Loughlin both found that PG&E's gas transmission and storage business standing alone generated more revenues than were needed to cover its actual costs and provide a return at the authorized rate. Put another way, viewed in isolation, GT&S generated actual rates of return that exceeded the authorized rates of return. Specifically, Mr. Harpster found that GT&S's revenues exceeded the amount needed to earn the authorized rate of return on equity (ROE) by $435 million from 1999 to 2010.[760] He also found that GT&S standing alone earned an average ROE of 14.3% from 1999 to 2010 (compared to the average authorized ROE of 11.2%).[761] Mr. O'Loughlin calculated similar results (although how they arrived at those conclusions was different).[762] These facts standing alone, however, provide no basis for penalizing PG&E.

a. PG&E Should Not Be Penalized For Benefitting From The Incentives Provided By The Gas Accord Structure

The first Gas Accord unbundled PG&E's gas transmission and storage system, and created separate rates for different backbone transmission paths, local transmission, and storage services.[763] Under the Gas Accord, PG&E was not assured any cost recovery for the portion of the revenue requirement associated with non-core customers (with the exception of certain customers who entered into G-XF contracts) and was entirely "at risk" for these revenues.[764] This was in contrast to PG&E's other lines of business (e.g., gas and electric distribution), which have balancing accounts to protect PG&E against revenue fluctuations. Without balancing account protection, GT&S revenues either could exceed or fall below its revenue requirement.[765] And, while PG&E was placed at risk for substantial portions of its revenue requirement, it was

[760] Ex. CPSD-170 at 10 (Table 3-6) (CPSD/Harpster).

[761] Ex. CPSD-170 at 10 (Table 3-5) (CPSD/Harpster).

[762] Ex. PG&E-10, MPO-1 at 66-67 (PG&E/O'Loughlin).

[763] Ex. PG&E-10, MPO-1 at 9 (PG&E/O'Loughlin).

[764] Ex. PG&E-10, MPO-1 at 11 (PG&E/O'Loughlin).

[765] Ex. PG&E-10, MPO-1 at 63 (PG&E/O'Loughlin).

given flexibility in the prices it could charge for non-core backbone transmission and storage services.[766]

PG&E's gas storage business consists of several components: injection, inventory (storage) and withdrawal, as well as parking and lending services. "Parking" allows customers to store gas when commodity prices are relatively low and withdraw the gas when prices are higher.[767] "Lending" allows customers to borrow gas when commodity prices are relatively high and repay the gas when prices are lower.[768] Under the Gas Accord, the maximum approved rates for unbundled (non-core) storage were set so that PG&E could collect the total unbundled storage revenue requirement from each individual storage component (injection, inventory, withdrawal).[769] In other words, GT&S could recover more than its cost of service if it was successful in selling all of its injection, withdrawal and inventory rights at the maximum rate.[770] GT&S's parking and lending rates were also designed to recover the same cost of service allocated to the unbundled storage program.[771] Thus, the parking and lending rates provided an additional opportunity for PG&E to recover more than the allocated annual unbundled storage costs depending on the frequency and duration of transaction activity and the degree to which there was offsetting parking and lending activity.[772] This treatment of unbundled storage by the Commission was not unique to PG&E. The Commission also allowed SoCalGas the opportunity to generate more revenues than needed to cover the cost of its unbundled storage service.[773] The Commission wanted to encourage PG&E and the other utilities to compete in the storage market by allowing them to capture the transactional value of storage as external market conditions would allow.[774]

Just as CPSD's and PG&E's experts generally agree about the extent of the revenues and returns generated by GT&S, they both agree that PG&E was able to earn these revenues because

[766] Ex. PG&E-10, MPO-1 at 62 (PG&E/O'Loughlin).
[767] Ex. CPSD-170 at 135 (CPSD/Harpster).
[768] Ex. CPSD-170 at 135 (CPSD/Harpster).
[769] Ex. PG&E-10, MPO-1 at 71 (PG&E/O'Loughlin).
[770] Ex. PG&E-10, MPO-1 at 72 (PG&E/O'Loughlin).
[771] Ex. PG&E-10, MPO-1 at 73 (PG&E/O'Loughlin).
[772] Ex. PG&E-10, MPO-1 at 73 (PG&E/O'Loughlin).
[773] Ex. PG&E-10, MPO-1 at 73-74 (PG&E/O'Loughlin).
[774] Ex. PG&E-10, MPO-1 at 75 (PG&E/O'Loughlin).

of the success of its market storage business.[775] Both Mr. Harpster and Mr. O'Loughlin found that PG&E's at risk parking and lending services – not storage (or transmission) services provided to core customers – generated the vast majority of the revenues in excess of the adopted revenue requirements.[776] The value of storage services, and parking and lending in particular, depends on seasonal price differences and gas price volatility – factors outside PG&E's control.[777] Seasonal pricing spreads grew substantially during much of the period at issue.[778] Because of these external market conditions, PG&E was able to sell parking and lending services at quantities and prices that exceeded what was necessary to cover the revenue requirement used to design the parking and lending rates.[779] These "surplus" parking and lending revenues, however, were by no means certain. Storage market fundamentals in the North American gas market deteriorated significantly in 2011 and 2012.[780] At risk storage revenues fell by more than 70% from 2010 to 2011.[781]

The fact that PG&E's GT&S line of business generated revenues that allowed it to earn rates of return that were higher on average than the authorized rates of return does not provide a basis for the Commission to conclude that PG&E emphasized profits over safety or acted improperly in any way. Even putting aside the market storage business, a regulated utility, particularly one using a forward test-year approach like PG&E, is unlikely to earn exactly the authorized ROE.[782] This is a normal result, and there is nothing improper with earning more than the authorized rate of return.[783] Indeed, the Commission actively encourages utilities to operate as efficiently as possible by providing them the opportunity to retain the benefit of any cost savings during a rate case cycle:

> We know in prospective test year ratemaking that our adopted estimates of revenues and expenses may be at variance with actual hindsight experience. But we do not view this as a problem,

[775] Ex. PG&E-10, MPO-1 at 64 (Figure 17) (PG&E/O'Loughlin); Ex. CPSD-170 at 136-37 (CPSD/Harpster) ("[g]iven the relative stability of their revenue streams, it is reasonable to conclude that core storage and balancing did not earn significantly more than their authorized return on equity").

[776] Ex. CPSD-170 at 134 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 68-70 (PG&E/O'Loughlin).

[777] Ex. PG&E-10, MPO-1 at 70 (PG&E/O'Loughlin); R.T. 220-21 (CPSD/Harpster).

[778] Ex. PG&E-10, MPO-1 at 71 & Figure 21 (PG&E/O'Loughlin).

[779] R.T. 219-20 (CPSD/Harpster).

[780] Ex. PG&E-10, MPO-1 at 75-76 (PG&E/O'Loughlin).

[781] Ex. PG&E-10, MPO-1 at 75-76 (PG&E/O'Loughlin).

[782] Ex. PG&E-10, MPO-1 at 78 (PG&E/O'Loughlin); R.T. 237 (CPSD/Harpster).

[783] Ex. PG&E-10, MPO-1 at 78 (PG&E/O'Loughlin).

> because we are extending to utility management an opportunity and incentive to find ways to conduct operations for less than projected.[784]

In assessing the significance of GT&S's return history, it is especially important to consider the rate case structure because, as discussed above, GT&S did not have the same balancing account protection as PG&E's other Commission -regulated lines of business. Instead, the Gas Accord structure that remained in place throughout the period permitted – and even encouraged – PG&E to generate more revenues than its cost of service for its at-risk storage business if market conditions allowed.[785] And, in fact, GT&S was able to generate revenues in excess of its cost of service because market conditions were favorable during much of this period.[786] Furthermore, the settling parties continually agreed to, and the Commission approved, rate structures that allowed PG&E to generate storage revenues that exceeded its adopted storage revenue requirement. All of the settlement agreements following Gas Accord I (until Gas Accord V) continued this same structure.[787] The Commission explicitly approved this pricing structure in the only fully litigated case (in 2004).[788] Not only did the parties repeatedly sign off on this pricing structure, they also were (or should have been) aware that PG&E's market storage business was generating revenues that exceeded its cost of service.[789] It was not until the Gas Accord V settlement on August 20, 2010 that the parties agreed to share "surplus" storage revenues between PG&E and ratepayers (and, in return, PG&E received balancing account protection).[790] In short, the fact that PG&E benefitted from the very incentives approved by the Commission in the Gas Accords to generate revenues in excess of its cost of service should not now be a ground for penalizing PG&E. *See, e.g*., *Application of Pacific Gas & Electric Company, etc,* D.96-012-066, 1996 Cal. PUC LEXIS 1111, at *4 ("[A]ny form of ratemaking creates incentives. By establishing a three-year base revenue cycle, the Commission knowingly

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[784] *Application of Pacific Gas and Electric Company, etc*, D.96-12-066, 1996 Cal. PUC LEXIS 1111, at *5 (quoting D.85-03-037, 1985 Cal. PUC LEXIS 104; 17 CPUC 2d 246, 254).

[785] Ex. PG&E-10, MPO-1 at 77 (PG&E/O'Loughlin).

[786] Ex. PG&E-10, MPO-1 at 69-70, 77-78 (PG&E/O'Loughlin).

[787] Ex. PG&E-10, MPO-1 at 73 (PG&E/O'Loughlin).

[788] *See* Ex. PG&E-11, MPO-34; Ex. PG&E-10, MPO-1 at 73 n.114 (PG&E/O'Loughlin).

[789] *See* Ex. PG&E-10, MPO-1 at 73 n.116 (PG&E/O'Loughlin); Ex. PG&E-11, MPO-35; Ex. CPSD-303; R.T. 659-62, 664 (PG&E/O'Loughlin) (discussing how the information in Ex. CPSD-303 shows that PG&E's storage revenues exceeded the revenue requirement by a significant amount).

[790] R.T. 222 (CPSD/Harpster).

provided an incentive for the utilities to become more productive in the years between test years.").

b. GT&S's Higher-Than-Authorized ROE Was Not The Result Of Underspending On O&M Or Capital

GT&S viewed as a standalone entity was able to earn higher-than-authorized returns because of the strong revenues generated by its competitive market storage business, not because of any underspending on capital or O&M.[791] As Mr. O'Loughlin testified, there is no connection between GT&S earning above-authorized returns and any underspending by PG&E – PG&E in fact spent more than the imputed adopted O&M and capex amounts from 1997 to 2010.[792] Furthermore, there is no dispute that, under the Commission's GT&S rate case decisions, PG&E was not required to spend any "surplus" revenues within the GT&S business, but was permitted to use them for other company purposes.[793] While PG&E was obligated to spend what is necessary to maintain a safe and reliable system, both Mr. O'Loughlin and Mr. Harpster agree that PG&E spent more than the imputed adopted safety-related capital expenditures during the period for which they were able to perform that analysis.[794] And, as discussed above, Mr. Harpster never offered any evidence that PG&E spent less than the safety-related O&M or capex during any period.[795]

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[791] Ex. PG&E-10, MPO-1 at 78 (PG&E/O'Loughlin). In fact, the ROE of the transmission part of GT&S (i.e., not including storage) was lower than the authorized rate in 6 of the 12 years from 1999 to 2010 and the transmission business never earned significantly more than the authorized rate except in 2001, which was due to highly unusual market conditions during the California energy crisis. Ex. PG&E-10, MPO-1 at 67 (Figure 19) (PG&E/O'Loughlin); *id.* at 68.

[792] Ex. PG&E-10, MPO-1 at 78 (PG&E/O'Loughlin). Mr. Harpster contends that Mr. O'Loughlin's finding that GT&S generated more revenues than needed to earn the authorized rate of return calls into question his conclusion that PG&E spent more than the imputed adopted O&M and capex amounts. *See* Ex. CPSD-170 at 130 (CPSD/Harpster). This argument is based on the mistaken premise that any difference between GT&S's adopted and actual revenue requirements was due to either higher than adopted revenues or underspending on O&M and capex. (The "actual revenue requirement" differs from the adopted revenue requirement in that it is based on actual O&M and other expenses and the actual rate base receiving the authorized rate of return. Ex. PG&E-10, MPO-1 at 65 (PG&E/O'Loughlin).) In fact, a difference in any component of the revenue requirement could cause a difference between the adopted and actual revenue requirement. R.T. 218 (CPSD/Harpster) ("There certainly could be [other factors explaining the difference between adopted and actual revenue requirements]. You know A&G expenses, there's other expenses that are not included in my functional O&M comparison and other rate base items.").

[793] Ex. CPSD-168 at 1-3 (CPSD/Harpster); Ex. CPSD-1 at 140 (CPSD/Stepanian) ("PG&E Company is generally permitted to redirect funds.").

[794] Ex. PG&E-10, MPO-1 at 5, 78 (PG&E/O'Loughlin); Ex. CPSD-168 at 4-3 (CPSD/Harpster).

[795] *See* Section V.F.1.d.(i), *supra.*

c. The Utility As A Whole Earned Returns That Were Consistent With The Authorized Returns

The Commission should not focus on the revenues and returns for GT&S standing alone in any event. PG&E is a single gas and electric utility, and it is managed as such. Consistent with this single utility model, PG&E allocates its financial resources through an enterprise-wide planning and budgeting process. Funding for a particular line of business is not limited to the specific revenues generated by that line of business. Budgets are set for each line of business according to established operating priorities rather than specifically by the revenue source.[796] Through PG&E's budgeting and planning process the "surplus" storage revenues were available to all lines of business based on their operational needs. It is inconsistent with the way PG&E manages its business to focus on whether a single part of the utility had "surplus" revenues or "excess" returns. GT&S's "surplus" storage revenues were simply one component of the utility's overall revenues.[797]

The Commission therefore should con sider PG&E's overall returns before drawing any conclusions based solely on the success of GT&S's storage business. The utility as a whole earned returns that were consistent with the Commission-authorized rates.[798] In fact, returns were lower than the authorized rates in seven of the 12 years from 1999 to 2010, with an average ROE of 4.7% compared to an average authorized ROE of 11.2%.[799] Even focusing only on the most recent years (after the energy crisis and PG&E's bankruptcy), the utility's average retur n of 11.7% was only slightly higher than the average authorized rate of 11.3%.[800] The rates of return on PG&E's combined gas business (gas distribution and GT&S) also have been consistent with

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[796] Ex. PG&E-10, MPO-1 at 79 (PG&E/O'Loughlin).

[797] Ex. PG&E-10, MPO-1 at 82 (PG&E/O'Loughlin).

[798] Ex. PG&E-10, MPO-1 at 80 (Figure 23) (PG&E/O'Loughlin); Ex. PG&E -11, MPO-38. The earnings information that is summarized in Mr. O'Loughlin's testimony comes from annual earnings reports that PG&E regularly provided to the Commission. *See* Ex. PG&E-11, MPO-38 at 16; R.T. 223 (CPSD/ Harpster); *see also* CPUC Rule of Practice and Procedure 3.2(a)(1)(5) (requiring rate of return summary with applications for authority to increase rates). The Commission should disregard Mr. Harpster's contention that these reports should be viewed "with skepticism" (*see* Ex. CPSD-170 at 146 (CPSD/Harpster)) in light of his own admission that he did not perform the necessary analysis to back up his assertions. *See* R.T. 231-32 (CPSD/Harpster) (acknowledging he did not "attempt[] to audit these documents"). For example, Mr. Harpster contends that PG&E "*may have* distorted" its reported earnings by including $412 million in bankruptcy costs (Ex. CPSD-170 at 145-46 (CPSD/Harpster) (emphasis added)), but on cross-examination he admitted that he has "*no idea* whether they're included in those earnings reports or not." R.T. 236 (CPSD/Harpster)(emphasis added).

[799] Ex. PG&E-10, MPO-1 at 79-80 (PG&E/O'Loughlin).

[800] Ex. PG&E-10, MPO-1 at 80 n.130 (PG&E/O'Loughlin).

the Commission's authorized rates.[801] In short, PG&E's return history is in line with what one would expect – in some years PG&E earned more than the authorized rate and in other years less, and PG&E did not earn consistently more than the authorized rate of return over a significant number of years in a row.[802]

d. There Is No Evidence That PG&E Used "Surplus" GT&S Revenues For Anything Other Than Utility Operations

While PG&E agrees that it is not possible to trace how particular funds are used, the evidence indicates that PG&E used the GT&S revenues not spent within GT&S for other operational purposes, including for gas distribution.[803] If PG&E had not used the "surplus" storage revenues to fund utility operations, one would see higher-than-authorized rates of return for the entire utility, not just GT&S.[804] CPSD offers only speculation about how PG&E might have used GT&S revenues but provides no evidence that PG&E did not use the GT&S revenues for other operational purposes.[805] For his part, Mr. Harpster testified that he did not try to determine how PG&E used the so-called "surplus" revenues and stated that tracing the funds likely would not be possible.[806]

The bottom line is that it would be inappropriate to draw any conclusions – one way or another – about PG&E's safety culture or whether it valued profits over safety based on the fact that, viewed as a standalone business, GT&S generated returns that on average were higher than the authorized rates of return.

3. CPSD Failed To Prove That PG&E Valued Profits Over Safety

CPSD has made sweeping statements about how PG&E allegedly prioritized financial performance over safety. But it has failed to offer any concrete evidence to back up those assertions. For the reasons already discussed, PG&E's spending on GT&S compared to what it received in its rate cases provides no basis for concluding that PG&E valued profits over safety. The same is true with respect to the earnings history of GT&S, especially given that the utility

[801] Ex. PG&E-10, MPO-1 at 79-80 (PG&E/O'Loughlin).
[802] Ex. PG&E-10, MPO-1 at 81 (PG&E/O'Loughlin).
[803] PG&E-10, MPO-1 at 83 (PG&E/O'Loughlin).
[804] PG&E-10, MPO-1 at 83 (PG&E/O'Loughlin).
[805] *See* Ex. CPSD-1 at 140-44 (CPSD/Stepanian) (discussing "possible redirections of operational revenues").
[806] R.T. 210-11 (CPSD/Harpster).

earned returns that were consistent with the authorized rates of return. The remaining sections of the Overlan d Report and CPSD's own "safety culture" testimony also provide no basis for penalizing PG&E based on its past spending. While in hindsight one might argue that PG&E ought to have invested more in the gas transmission system, that does not mean that PG&E's officers and managers at the time were more concerned about financial performance than safety. To the contrary, as Ms. Yura testified, PG&E did not lose its "focus on safety" and was not "overly focused on financial performance."[807]

a. The Overland Report Does Not Identify Any Safety Issues For Which PG&E Did Not Provide Funding

The Overland Report purports to address whether budget limitations detrimentally affected the safety of PG&E's gas transmission operations. One of Overland's "key" findings – that PG&E's "consistent underspending on transmission O&M has negative implications for gas pipeline safety"[808] – is based entirely on Overland's comparison of its imputed adopted O&M amounts to PG&E's actual O&M expenses. For the reasons discussed above, that analysis is flawed and it therefore cannot support any conclusion about the effects of spending patterns on safety. Overland's conclusion that PG&E "placed excessive emphasis on meeting financial goals"[809] also lacks support given that PG&E spent more than the imputed adopted amounts, not less, and the utility as a whole earned less than the authorized return in seven of the 12 years studied by Overland.[810]

Furthermore, the Overland Report does not identify any specific work whose alleged cancellation or deferral for budget reasons raised safety concerns. For example, the report discusses PG&E having changed or deferred integrity management assessments to reduce O&M costs from 2008 to 2010. But Overland did not establish that any methodology change or deferral impaired safety in any way (much less that any of those decisions violated the provisions of 49 C.F.R. Part 192, Subpart O). Overland's lack of specificity is consistent with the fact that it reviewed PG&E's gas transmission and storage business from a *"financial and ratemaking*

[807] R.T. 974, 978 (PG&E/Yura).
[808] Ex. CPSD-168 at 1-1 (CPSD/Harpster).
[809] Ex. CPSD-168 at 1-1 (CPSD/Harpster).
[810] *See* Section V.F.2.c., *supra.*

perspective," not from an operational or engineering one. [811] Indeed, Overland did not have the necessary expertise to make any specific safety determinations. None of the members of the Overland team has engineering expertise.[812]

b. The Budget Constraints In 2008 To 2010 Discussed By Overland Did Not Affect Line 132

Not only did Overland not identify any specific safety concerns with regard to decisions by PG&E in 2008-2010 to change or defer certain integrity management assessments, Overland does not contend that those decisions affected Line 132. [813] Mr. Martinelli's testimony confirms that none of the changes in 2008 to 2010 to planned integrity management assessments involved Line 132.[814] Nor is there any evidence that budget constraints led to the deferral of a planned project to replace Line 132 between mile posts 42.13 and 43.55. [815] Instead, PG&E deferred that project after concluding, based on information from engineering evaluation and investigation, that the project was not as high a priority relative to other projects as originally thought.[816]

c. The "Safety Culture" Section Of CPSD's Report Offers Nothing But Unsupported Assertions That Fail To Show That PG&E Valued Profits Over Safety

The so- called "safety culture" section of CPSD's San Bruno report consists of nothing but a disconnected series of irrelevant facts, unsupported assertions, rife speculation, and innuendo that individually and collectively do not prove that PG&E valued profits over safety. [817] This section of CPSD's report is untethered from anything affecting the safety of Line 132 or any other subject addressed by this proceeding. For example, CPSD speculates for pages about how PG&E may have used GT&S revenues for dividends, stock repurchases, officer financial incentives and bonuses, environmental cleanup, payments to subsidiaries, and so on. [818] But not only does CPSD concede that this entire discussion is speculative – a litany of purported

[811] Ex. CPSD-168 at 1-2 (CPSD/Harpster) (emphasis added); R.T. 56 (CPSD/Harpster).
[812] R.T. 237-38 (CPSD/Harpster).
[813] Ex. CPSD-168 at 7-7 to 7-9, 8-2 to 8-5, 9-8 to 9-12 (CPSD/Harpster).
[814] Ex. PG&E-1 at 12-3 to 12-4 (PG&E/Martinelli).
[815] Ex. PG&E-1 at 12-3 to 12-4 (PG&E/Martinelli).
[816] Ex. PG&E-1 at 12-3 to 12-4 (PG&E/Martinelli).
[817] *See* Ex. CPSD-1 at 126-161 (CPSD/Stepanian).
[818] *See* Ex. CPSD-1 at 140-44 (CPSD/Stepanian).

"possible redirections of operational revenues"[819] – CPSD's own expert testified that it is not possible to determine how PG&E may have used GT&S revenues that it did not spend within the GT&S business.[820] The record in fact indicates that PG&E used any "surplus" GT&S revenues on other utility operations.[821]

VI. OTHER ALLEGATIONS RAISED BY TESTIMONY OF TURN

[Intentionally left blank]

VII. OTHER ALLEGATIONS RAISED BY TESTIMONY OF CCSF

[Intentionally left blank]

VIII. OTHER ALLEGATIONS RAISED BY TESTIMONY OF CITY OF SAN BRUNO

[Intentionally left blank]

IX. CONCLUSION

PG&E is deeply sorry for the September 9, 2010 pipeline rupture and explosion. PG&E is responsible for that terrible accident. In 1956, a PG&E construction crew installed a piece of defective pipe that never should have been put into service. Fifty-four years later that pipe caused the worst accident in the 100-year history of PG&E. Besides compensating the victims and the City of San Bruno, PG&E believes its sincerest apology lies in the major improvements it is making based on the lessons learned from this accident. At the end of that process – and with the support of the Commission through its Gas Safety Rulemaking (R.11-02-019) – PG&E will have one of the safest gas systems in the country.

The hardest task the Commission has in this proceeding is separating PG&E's acknowledgement of responsibility and liability to the injured from the narrower question of PG&E's compliance with laws and regulations. Aside from the admitted violations of 49 C.F.R. § 192.13(c) in its clearance procedure and 49 C.F.R. § 199.225 in its alcohol testing, the evidence shows that PG&E complied with the applicable laws and regulations.

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[819] Ex. CPSD-1 at 140 (CPSD/Stepanian).

[820] R.T. 210-11 (CPSD/Harpster).

[821] *See* Section V.F.2.d., *supra*.

The burden of proof of violations is CPSD's alone. CPSD has alleged violations of specific pipeline safety regulations and, where the pipeline regulations would not support faulting particular actions, CPSD used an expansive and improper interpretation of Public Utilities Code Section 451. Whether the Commission applies the clear and convincing evidence standard PG&E believes is required or the lesser preponderance of the evidence standard, the record, which includes the testimony of preeminent experts in the industry, shows that CPSD has not met its burden of proof:

- CPSD based its alleged violations regarding Segment 180 construction and recordkeeping on non-mandatory industry guidelines, not valid legal authority, and the facts refuted the alleged violations in any event;
- The violations CPSD alleges today regarding PG&E's integrity management program are contradicted by CPSD's own assessment of that program in May 2010 – just four months before the accident. The current allegations related to Line 132 and Segment 180, as well as the blanket indictment of PG&E's integrity management program, were based on CPSD's erroneous application of the regulations, speculation, hindsigh t judgments and information known only after the accident;
- CPSD's alleged violations related to PG&E's SCADA system and Milpitas Terminal were entirely undermined by the undisputed fact that the pressure control system on Line 132 operated exactly as intended and kept pressure below MAOP and well below what was allowed by law;
- Alleged violations regarding PG&E's written emergency plans were shown to be meritless by PG&E's expert witness, as well as by CPSD's own consultant in the Records OII who conceded PG&E's emergency plans complied with applicable regulations;
- CPSD's alleged violations related to PG&E's emergency response on September 9, 2010 derived from subjective judgments and changed expectations following the accident; and
- Lastly, though CPSD did not allege legal violations in the area, CPSD's criticisms of PG&E's budgetary and spending practices and its safety culture were shown to be unfounded and based on an erroneous financial analysis.

PG&E accepts responsibility for the Line 132 rupture and has made numerous changes to its organization, management and procedures to ensure that such an accident never happens again. But PG&E cannot agree that it violated the law in all the ways CPSD alleges. As demonstrated in detail in this brief, the evidence shows CPSD has not proven the vast majority of the violations it asserted against PG&E.

Respectfully submitted,

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Dated: April 3, 2013

APPENDIX A

PROPOSED FINDINGS OF FACT

September 9, 2010 Line 132 Accident

1. On September 9, 2010, three PG&E employees and one contractor were working on a scheduled clearance as part of a replacement project for the uninterruptable power supply (UPS) at the Milpitas Terminal. Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 7 (CPSD/Stepanian).

2. Before commencing the work, the crew held a tailboard meeting to discuss the steps that needed to be performed. Ex. PG&E-1 at 8-5, 8-8 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-9 (NTSB Report) at 54; Ex. CPSD-12 at 10.

3. Transcripts of recorded phone calls between the Milpitas Terminal gas technician and Gas Control Operator show that the gas technician described the steps that they were going to take on September 9, 2010 prior to commencing the UPS work. Ex. PG&E-1 at 8-5, 8-8 to 8-9 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-40 at 1-2; Ex. CPSD-1 at 84 (CPSD/Stepanian).

4. Throughout the scheduled clearance, the crew updated Gas Control before taking steps that could affect Gas Control Operators' ability to monitor or control station equipment. Ex. PG&E-1 at 8-5, 8-8 to 8-9 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-40 at 1-2; Ex. CPSD-12 at 15-16.

5. The gas technician notified Gas Control that they would temporarily lose the SCADA monitoring and controlling ability as they switched certain valves from Auto to Manual. Ex. PG&E-1 at 8-8 to 8-9 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 84 (CPSD/Stepanian).

6. At approximately 5:22 p.m., power was unexpectedly lost at Milpitas Terminal to devices being provided 24 Volt DC power from two power supplies, PS-A and PS-B. Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager); Joint R.T. 115 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 87 (CPSD/Stepanian).

7. The 24 Volt DC Power Supplies PS-A and PS-B provide power to many of the pressure sensor current loops at Milpitas Terminal. The pressure sensors provide pressure feedback to the pressure controllers that modulate the pressure regulating valves to maintain pressure at the set point value. Ex. CPSD-1 at 79 (CPSD/Stepanian); *see also* Ex. PG&E-1 at 8-5 to 8-6 (PG&E/Kazimirsky/Slibsager).

8. The power failure to power supplies PS-A and PS-B caused various regulating valves to fully open as designed. Gas pressure in lines leaving the Milpitas Terminal, including Lines 101, 109 and 132 increased. Ex. PG&E-1 at 8-6

(PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8, 9-13 (PG&E/Miesner); Ex. CPSD-1 at 8 (CPSD/Stepanian).

9. At approximately 5:23 p.m., records of SCADA alarms and pressure readings indicate valves opening and pressure increasing at Milpitas Terminal. Ex. CPSD-1 at 87 (CPSD/Stepanian).

10. At 5:23 p.m., the Gas Operators in San Francisco observed High-High alarms at Milpitas and along the Peninsula pipelines. Ex. PG&E-40 at 2; Ex. CPSD-1 at 87 (CPSD/Stepanian).

11. The Contract Engineer and PG&E personnel began troubleshooting, and later identified the source of the electrical problem as the 24 Volt power supplies PS- A and PS-B. The voltage fluctuations resulted in a malfunction of the pressure instruments and communication of pressure information over the current loops to the valve controllers. Ex. CPSD-1 at 87 (CPSD/Stepanian); Ex. PG&E-1 at 8- 7 (PG&E/Kazimirsky/Slibsager).

12. Unrelated to the pressure increase, three of the valve controllers at Milpitas Terminal suffered a rare type of programming malfunction and the manufacturer had to be contacted to advise how to correct it. This malfunction is thought to have resulted from electrical connections being disconnected and reconnected during the troubleshooting at Milpitas Terminal. Ex. CPSD-1 at 88 (CPSD/Stepanian).

13. Gas Control contacted the gas control technician to discuss the high pressure alarms and monitor and manually close various valves. Ex. PG&E-40 at 3-5.

14. PG&E's redundant pressure limiting system at Milpitas Terminal and on Line 132 functioned as designed and kept the pressure on Line 132 and at the rupture site below the maximum allowable operating pressure (MAOP) of 400 psig. Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); PG&E-1 at 9-13 to 9-14 (PG&E/Miesner); Ex. CPSD-1 at 90-91 (CPSD/Stepanian).

15. The pressure limiting system kept the pressure within Milpitas Terminal to approximately 396 psig and thereafter restored pressure to the monitor valve set point of 386 psig. Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 90-91 (CPSD/Stepanian).

16. At approximately 5:52 p.m., Gas Control reduced the pressure set points of regulator valves at stations upstream to Milpitas Terminal to 370 psig as a further precaution. Ex. PG&E-1 at 9-9 (PG&E/Miesner); Ex. PG&E-40 at 4; Ex. CPSD- 1 at 89 (CPSD/Stepanian).

17. Despite efforts by PG&E personnel to monitor and reduce pipeline pressures, at 6:11 p.m., Line 132 experienced a line rupture at Segment 180. Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 7 (CPSD/Stepanian).

18. At the time of the rupture (6:11 p.m.), gas control operators had for approximately 50 minutes been receiving and attempting to integrate and analyze a mixture of valid and invalid SCADA data and alarms. Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8 to 9-9 (PG&E/Miesner).

19. The first San Bruno Police Department resources were dispatched at 6:11 p.m. and arrived at 6:12 p.m. R.T. 370-71 (PG&E/Almario); Ex. PG&E-40 at 5.

20. The San Bruno Fire Department's alarm sounded at 6 :12 p.m., and the fire department unit arrived on-scene at 6:17 p.m. R.T. 370-71 (PG&E/Almario); Ex. PG&E-40 at 5.

21. PG&E on-call and off-duty personnel began responding immediately upon becoming aware of an unidentified fire in the San Bruno area. Ex. PG &E-40 at 6-9; R.T. 415-16 (PG&E/Bull); R.T. 349-50 (PG&E/Almario).

22. Concord Dispatch, PG&E's gas dispatch center whose territory includes the Peninsula gas transmission system, first learned of a fire in San Bruno at 6:18 p.m., and contacted an off-duty PG&E employee (Gas Service Representative [GSR]) to ask whether he could see the fire. Ex. CCSF-2 at 1.

23. Between 6:18 p.m. and 6:23 p.m., Concord Dispatch received calls from several off-duty PG&E personnel reporting the fire. Ex. PG&E-40 at 6; Ex. CCSF-2 at 1; R.T. 351-53 (PG&E/Almario).

24. Upon learning of the rupture, PG&E employees began working to shut off the flow of gas. Ex. CCSF-2 at 1.

25. At 6:23 p.m., Concord Dispatch contacted the on-duty GSR and directed him to respond to the site. Ex. PG&E-4 0 at 6; R.T. 379-80 (PG&E/Almario). By 6:25 p.m., Concord Dispatch had notified the Peninsula Division on-call supervisor of the event, and the supervisor began making call-outs. Ex. CCSF-2 at 1; R.T. 381-82 (PG&E/Almario); Ex. PG&E-40 at 7. It was rush hour and the roads were crowded. R.T. 380-81 (PG&E/Almario).

26. At 6:27, Concord Gas Dispatch informed Gas Control of reports of the flames and that a GSR and a Supervisor were heading to the scene. Ex. CPSD-1 at 109 (CPSD/Stepanian).

27. Power was also lost at Milpitas Terminal to other station devices during the power failure, which rendered a number of the SCADA data points for Milpitas Terminal inaccurate or unreadable, and resulted in numerous SCADA alarms being sent to Gas Control. Ex. CPSD-1 at 11 (CPSD/Stepanian).

28. Gas Control continued to assess incoming SCADA information, which was comprised of both accurate pressure readings and unusual and inconsistent SCADA data resulting from the power failure at Milpitas Terminal. Ex. CPSD-1 at 11 (CPSD/Stepanian); Ex. PG&E-40 at 5-8 (PG&E/Almario).

29. The first low-low pressure alarm from Martin Station, downstream from the rupture, came in on the SCADA system at 6:15 p.m. Ex. PG&E-1 at 9-9 (PG&E/Miesner); Ex. CPSD-1 at 108 (CPSD/Stepanian).

30. Gas system operators analyzed the numerous incoming SCADA alarms and related data as efficiently and accurately as possible. Ex. PG&E-1 at 9-8 to 9- 9 (PG&E/Miesner).

31. At approximately 6:29 p.m., 14 minutes after the first low-low alarm and 2 minutes after first learning of the fire in San Bruno, Gas Control operators concluded that there likely had been a rupture on Line 132, and began contacting PG&E emergency response personnel. Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-5 (Tab 8-1); Ex. PG&E-1 at 9-9 (PG&E/Miesner); Ex. PG&E-40 at 7-8; Joint R.T. 118 (PG&E/Kazimirsky/Slibsager).

32. There was continual response by PG&E throughout the incident, including the dispatch of gas service representatives (R.T. 282, 381 (PG&E/Almario), dispatch of the Measurement & Control (M&C) personnel (Ex. PG&E-1 at 11-25 to 11-26 (PG&E/Bull)), coordination on scene with the fire department (Ex. PG&E-1 at 10-6 PG&E/Almario)), and identification and closing of valves (Ex. PG&E-40 at 4-5). R.T. 415-16 (PG&E/Bull); Ex. PG&E-1 at 11-28 (PG&E/Bull); R.T. 295 (PG&E/Almario).

33. After being contacted by Concord Dispatch at approximately 6:25 p.m., the Peninsula Division on-call supervisor called the Peninsula Division Transmission & Regulation (T&R) Supervisor, and the field personnel on his call-out list, including the Measurement & Control (M&C) mechanics assigned to the area. When the on-call supervisor reached the M&C mechanics several minutes later, he instructed the mechanics to go to the Colma Yard to retrieve their trucks and equipment to shut the necessary valves on Line 132. R.T. 404-05, 408-09 (PG&E/Almario); Ex. CPSD-13 at 10-11, 18-19, 23-23. Two mechanics are needed to shut the valves, which often are large, difficult to turn and isolated underground. R.T. 391-92 (PG&E/Almario).

34. At 6:30 p.m., Concord Dispatch called to check in with a GSR who has been dispatched to site. GSR advises that he can see flames but is in traffic. Dispatcher informs him that he just received a report that it sounds like a gas station blew up. Concord Dispatch also advises GSR that a supervisor is also en route. Ex. PG&E-40 at 7-8.

35. At 6:35 p.m., a PG&E M&C mechanic saw the fire from his house and headed to PG&E's Colma Yard to retrieve a truck and tools. R.T. 382 -85, 392-93 (PG&E/Almario); Ex. PG&E-40 at 8. The PG&E M&C mechanic reported to PG&E's Concord dispatcher that "the flame that is coming out is consistent with a transmission line." Ex. PG&E -40 at 8; Ex. PG&E-1 at 10-4 (PG&E/Almario). While en route, five minutes later at 6:40 p.m., the M&C mechanic was called by

the Peninsula Division On-Call Supervisor to report to the Colma Yard. R.T. 382-84, 404-05 (PG&E/Almario); Ex. PG&E-40 at 9.

36. Already on his way, the M&C mechanic continues to the yard, arriving at 6:50 p.m. Ex. PG&E-40 at 10; R.T. 389-90 (PG&E/Almario). He arrives and gathers his tools and maps. R.T. 390 (PG&E/Almario). He also speaks with his Supervisor about the plan to isolate the rupture. R.T. 391 (PG&E/Almario); Ex. PG&E-40 at 11. After the second arrives, the two M&C mechanics leave the yard at 7:06 p.m. Ex. PG&E-40 at 11; R.T. 391 (PG&E/Almario).

37. By 6:41 p.m., one supervisor and one GSR were at the scene communicating with the San Bruno Fire Department on-scene command center. Ex. CPSD-9 (NTSB Report) at 15; *see also* R.T. 285, 385-86 (PG&E/Almario).

38. The San Mateo County Sheriff called Concord Dispatch at 7:02 p.m. inquiring as to whether power in the area had been shut off and whether PG&E knew about a plane crash. Ex. PG&E-40 at 11.

39. At 7:06 p.m., the M&C mechanic called his temporary supervisor, informing him that he is going to isolate the rupture. The supervisor approves the plan. Ex. PG&E-40 at 11.

40. The responding M&C mechanics arrived at the upstream valve location at 7:20 p.m., and closed valve V-38.49 by 7:30 p.m. Ex. PG&E-40 at 11-12; Ex. CPSD-96 at 26-34. During that period, they had to open the gate to the San Andreas Station with a key, turn down the service road approximately 100 yards, take off the manhole cover over the valve, and place a wrench onto the valve and turn it 50 times. Ex. PG&E-40 at 11; Ex. CPSD-96 at 25-34.

41. At 7:29 p.m., Gas Control remotely closed the valves at Martin Station, isolating the pipeline several miles downstream of the rupture. Ex. PG&E-40 at 12.

42. After closing the upstream valve, the M&C mechanics travelled to and closed the two more valves downstream by approximately 7:45 p.m., which isolated the rupture at the closest possible locations. Ex. CPSD-1 at 12 (CPSD/Stepanian); R.T. 270-72 (PG&E/Almario); Ex. PG&E-40 at 13.

43. From the incident site, a PG&E Superintendent contacted Gas Control at 7:42 p.m. to notify it that the flames have diminished. Ex. PG&E-40 at 13.

44. During conditions in which the primary pressure regulating device fails, 49 C.F.R. § 192.201(a)(2)(i) requires that the pressure in a transmission pipeline not exceed the MAOP plus 10%. Ex. CPSD-1 at 24 (CPSD/Stepanian).

45. CPSD's investigation revealed that although PG&E received complaints regarding gas odor/leak from San Bruno and its neighboring areas prior to the explosion, complainants and PG&E records confirm that PG&E responded to these complaints by dispatching its crews to resolve the issues. CPSD did not

identify the existence of specific complaints, reported to PG&E or the Commission prior to the explosion, that originate at the site of the explosion or are related to the explosion itself. Ex. CPSD-1 at 14 (CPSD/Stepanian).

Line 132 and Segment 180 Construction

46. Line 132 was constructed in multiple phases from 1944 through 1948 and consists of 22-inch, 24-inch, 30-inch, 34-inch, and 36-inch diameter segments located in various lengths of the pipeline. Ex. CPSD-1 at 15 (CPSD/Stepanian).

47. 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. Ex. CPSD-1 at 7 (CPSD/Stepanian).

48. In 1948, PG&E first constructed the section of Line 132 that runs through San Bruno. Ex. PG&E-1 at 2-1 (PG&E/Harrison). PG&E ordered the pipe for that construction from Consolidated Western Steel Company, specifying 100,000 feet of 30-inch outside diameter, electric fusion welded, 0.375-inch wall thickness, 52,000 psig Specified Minimum Yield Strength (SMYS) steel pipe. Ex. PG&E- 1 at 2-1 (PG&E/Harrison); Ex. PG&E-5 (Tabs 2-1, 2-2); *see also* Ex. CPSD-9 (NTSB Report) at 28.

49. Most of the pipe lengths were to be double-wrapped prior to delivery to PG&E to protect against external corrosion. Ex. PG&E-1 at 2-1 to 2-2 (PG&E/Harrison); Joint R.T. 537 (PG&E/Harrison).

50. From 1954, PG&E pipe specifications for new purchases were based on API 5LX, Section VI, Dimensions, Weights, and Lengths for High Test Line Pipe, which required that no length used in making a jointer shall be less than 5 ft. Jointers are defined as two pieces joined by welding. Ex. CPSD-1 at 22 (CPSD/Stepanian); API 5LX, 5th Ed., Nov. 1954.

51. The API 5LX standard applies to pipe manufacturers. Ex. PG&E-1 at 2-6 (PG&E/Harrison). Consistent with API standards at that time, PG&E's pipe specifications stated that no more than 5% of the order could consist of jointers. Ex. CPSD-9 (NTSB Report) at 28-29; *see also* Ex. PG&E-1 at 2-2, 2-6 (PG&E/Harrison).

52. As additional quality assurance, PG&E engaged Moody Engineering Company to inspect the manufacturing process and testing of the Line 132 pipe at Consolidated Western's plant. Ex. PG&E -1 at 2-2 (PG&E/Harrison); Ex. PG&E-5 (Tab 2-1).

53. PG&E has not located Moody's report for that pipe purchase, but has located a Moody inspection report for pipe ordered approximately 3 months later from Consolidated Western for Line 153, the specifications for which were identical to the Line 132 pipe specifications. Ex. PG&E-1 at 2-2 (PG&E/Harrison); Ex. PG&E-5 (Tab 2-2).

54. The Moody report explained Consolidated Western's manufacturing process, and the quality assurance provided during the manufacturing process, as well as by Moody's inspection. Ex. PG&E-1 at 2-2 (PG&E/Harrison).

55. As the Moody report explained, the pipe was made using the "Union Melt" process, which involved double submerged arc welding (DSAW), whereby the long seam was welded first on the outside of the pipe and then on the inside. Ex. PG&E-1 at 2-2 (PG&E/Harrison); Ex. PG&E-5 (Tab 2-3).

56. In 1956, PG&E relocated a portion of Line 132 to accommodate a planned residential development in San Bruno. Ex. PG&E-1 at 2-3 (PG&E/Harrison); Ex. CPSD-1 at 15 (CPSD/Stepanian).

57. The 1956 project called for the use of approximately 1,900 feet of the same type of 30-inch DSAW pipe used in the 1948 Line 132 project, the 1949 Line 153 project and the 1953 Line 131 project. Ex. PG&E-1 at 2-3 (PG&E/Harrison). PG&E completed the job using pipe previously ordered from Consolidated Western but not used. Ex. PG&E-1 at 2-3 (PG&E/Harrison); Joint R.T. 378 (PG&E/Harrison).

58. DSAW pipe is considered by metallurgists in the gas transmission pipeline field today to be one of the highest-quality welded pipe. The same was true in 1956, when Segment 180 was constructed and installed. Ex. PG&E-1 at 3- 5 (PG&E/Caligiuri).

59. Absent any corrosion damage, well-manufactured DSAW pipe from the late 1940s or early 1950s would not have needed replacement merely due to its age in 2010 under any industry practice or standard. Ex. PG&E-1 at 3- 5 (PG&E/Caligiuri).

60. One small subsection of Segment 180, 23 out of 1,742 feet, was ultimately the cause of the September 2010 accident. That small section consisted of six short pipe segments, known as "pups," which were welded together. The pups ranged from 3.5 to 4.7 feet in length. Ex. PG&E-1 at 3-5 (PG&E/Caligiuri) ; Ex. CPSD-1 at 16 (CPSD/Stepanian).

61. The pups were wrapped to protect against corrosion, though PG&E does not know whether the pups were delivered to the construction site wrapped or unwrapped. Ex. PG&E-1 at 2-4 and 2-6 (PG&E/Harrison); Joint R.T. 345, 411 (PG&E/Harrison).

62. If the pups were delivered welded together and double-wrapped, PG&E would not have readily known about the existence or length of the pups. Ex. PG&E-1 at 2-7 (PG&E/Harrison).

63. Metallurgical examination and testing determined that the rupture occurred at a location on a longitudinal seam weld where there was a missing interior weld resulting in substandard yield strength in the weld. The DSAW weld at the

rupture location was not only missing its inside weld, it also had a ductile tear. Over time, the ductile tear in the seam weld grew, ultimately resulting in the rupture. Ex. CPSD-1 at 13, 20, 50 (CPSD/Stepanian); Ex. PG&E-1 at 3-5 to 3-10 (PG&E/Caligiuri); R.T. 1057, 1087 (PG&E/Caligiuri); CPSD-9 (NTSB Report) at 92-94.

64. NTSB metallurgical examination determined that yield strength values of all six pups were lower than 52,000 psig, which is PG&E's designated yield strength for the sections of Segment 180. Ex. PG&E-1 at 3-5 to 3-6 (PG&E/Caligiuri); Ex. CPSD-1 at 19 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 27. Four of the pups did not meet any known specification for carrier pipe, including PG&E specifications. Ex. CPSD-1 at 20 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 92; *see also* R.T. 1162 (PG&E/Caligiuri).

65. There is no evidence that the yield strength of the pipe material was a factor in the rupture. Ex. PG&E-1 at 3-6 (PG&E/Caligiuri).

66. A non-defective piece of pipe would not have ruptured due to the pressure increase on September 9, 2010. Ex. CPSD-1 at 91 (CPSD/Stepanian); Ex. PG&E-1 at 3-5 (PG&E/Caligiuri); CPSD-9 (NTSB Report) at 124.

67. There was no indication or evidence that PG&E ever had actual knowledge of the existence of the pup sections or the missing welds in the pup sections. Joint R.T. 368, 386 (PG&E/Harrison); Ex. PG&E-1 at 2-4 (PG&E/Harrison).

68. Unknown to PG&E, pups 1, 2 and 3 were welded on the seam from the outside and the weld did not penetrate through the inside of the pipe. No inside weld, required for acceptable DSAW pipe, was found on the inside of the pipe. Ex. PG&E-1 at 2-3 to 2-4 (PG&E/Harrison); *see also* Ex. CPSD-1 at 20 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 27.

69. None of the pups met the minimum 5-foot length requirement for jointers. Ex. CPSD-1 at 22 (CPSD/Stepanian).

70. Had PG&E known about the pups, it would have removed them from Segment 180. Joint R.T. 337 (PG&E/Harrison).

71. Pipe without a missing weld that met normal PG&E and industry standards at the time of its installation in 1956 would have withstood a pressure of 386 psig. Ex. CPSD-1 at 91 (CPSD/Stepanian); Ex. PG&E-1 at 3-5 (PG&E/Caligiuri); CPSD-9 (NTSB Report) at 124.

72. PG&E does not manufacture pipe and did not manufacture the pups installed on Segment 180. Joint R.T. 375-76 (PG&E/Harrison); R.T. 1081 (PG&E/Caligiuri); Ex. PG&E-1 at 3-4, 3-16 (PG&E/Caligiuri).

73. In the decades between PG&E's installation of Segment 180 in 1956 and the September 9, 2010 event, Segment 180 operated without incident. Ex. PG&E-1 at 2-4 (PG&E/Harrison); R.T. 1094 (PG&E/Caligiuri).

74. Wall thickness is a measurement applied to the pipe body and is not used to measure the thickness of seam welds or seam penetration. Joint R.T. 399-400 (PG&E/Harrison).

75. The wall thickness of the pipe body on pups 1, 2, and 3 was consistent with 0.375-inch specifications. Ex. PG&E-1 at 2-6 (PG&E/Harrison); CPSD-9 (NTSB Report) at 41.

76. CPSD withdrew its alleged violation regarding weldability under ASA B31.1.8-1955 in the Rebuttal Testimony of Raffy Stepanian. Ex. CPSD-5 at 7 (CPSD/Stepanian).

77. At the time Segment 180 was constructed in 1956, the Commission had jurisdiction over the safety of PG&E natural gas facilities but there were no specific federal or state safety regulations applicable to transmission line construction. Ex. CPSD-1 at 18 (CPSD/Stepanian); Ex. PG&E-1 at 2-4, 2-7 (PG&E/Harrison).

78. Adopted in 1955, the American Standards Association Code for Pressure Pipeline (ASA B31.1.8) was a voluntary industry standard. Ex. PG&E-1 at 2-4, 2-7 (PG&E/Harrison); Ex. PG&E-1 at 3-11 (PG&E/Caligiuri); Ex. CPSD-1 at 19 (CPSD/Stepanian).

79. ASA B31.1.8-1955 was a voluntary pipeline industry standard during the construction of Segment 180 of Line 132 in San Bruno in 1956. Ex. PG&E-1 at 2-4 (PG&E/Harrison); Ex. PG&E-1 at 3-11 (PG&E/Caligiuri); *see also* Ex. CPSD-1 at 19 (CPSD/Stepanian).

80. ASA B31.1.8-1955 did not mandate the use of X-52 strength pipe or any particular strength pipe. Ex. PG&E-1 at 2-5 (PG&E/Harrison).

81. The fact that the pups in Segment 180 did not meet the 52,000 psig SMYS standard does not violate ASA B31.1.8-1955, Section 805.54. Ex. PG&E-1 at 2-5 (PG&E/Harrison).

82. The "Grandfather Clause" in federal safety regulations expressly authorized pre-1970 pipelines to continue operating without hydrostatic testing. 49 C.F.R. § 192.619(a)(3); Ex. CPSD-1 at 23-24 (CPSD/Stepanian).

83. This clause specified that the MAOP for existing pipelines could be established based on the highest actual operating pressure to which the segment was subjected during the 5 years preceding 1970. Ex. CPSD-1 at 23 (CPSD/Stepanian).

84. The MAOP of 400 psig was appropriate when Segment 180 was installed. Ex. PG&E-1 at 2-10 to 2-11 (PG&E/Harrison).

85. The MAOP for Line 132 was established at 400 psig based on documentation showing an operating pressure of 400 psig at Milpitas Terminal in October 1968. Ex. CPSD-1 at 24 (CPSD/Stepanian).

86. The pipe with which Segment 180 was designed to be built, 30" DSAW, .375" wt, 52,000 psig SMYS pipe, supports an MAOP of up to 780 psig in a Class 2 location, and 650 psig in a Class 3 location, both well above the Segment 180 MAOP of 400 psig. Ex. PG&E-1 at 2-10 (PG&E/Harrison).

87. Using 32,000 psig SMYS as the "weakest" section of Segment 180, the allowed MAOP for Segment 180 when installed in 1956 in a Class 2 location would have been 480 psig. At the time of the San Bruno accident, Segment 180 was in a Class 3 location. Even so, the design basis formula still supports an MAOP of 400 psig in a Class 3 location. Ex. PG&E-1 at 2-11 (PG&E/Harrison).

88. The rupture on Segment 180 initiated with a ductile tear at the root of the externally welded longitudinal seam on pup 1, which over time, experienced fatigue crack growth ultimately resulting in the rupture. Ex. PG&E-1 at 3-5 to 3-17 (PG&E/Caligiuri).

89. The long seam weld, not the body of the pipe failed. The yield strength of the pipe was not a contributing cause of the rupture. Ex. PG&E-1 at 2- 5 (PG&E/Harrison); Ex. PG&E-3 at 3-5 to 3-6 (PG&E/Caligiuri).

90. The NTSB ruled out corrosion, seismic activity, and a 2008 sewer repair as possible causes of the ductile tear. Ex. PG&E-1 at 3-15 (PG&E/Caligiuri); R.T. 1087 (PG&E/Caligiuri); Ex. CPSD-9 (NTSB Report) at 88.

91. In 1956, the technology to conduct post-installation hydrostatic pressure tests was still relatively new. Ex. PG&E-1 at 2-7 (PG&E/Harrison); Ex. PG&E-1 at 3-11 (PG&E/Caligiuri).

92. When Segment 180 was constructed, post-installation pressure-testing had not yet been widely adopted in the gas pipeline industry. Ex. PG&E-1 at 2-7 (PG&E/Harrison); Ex. PG&E-1 at 3-11 (PG&E/Caligiuri).

93. Regulations requiring hydrostatic testing of new pipelines did not go into effect in California until 1961, and under federal law until the 1970s. Ex. PG&E-1 at 3-11 (PG&E/Caligiuri). Both the 1961 state regulations and 1970 federal regulations exempted existing pipelines from pressure testing requirements. Ex. PG&E-1 at 2-8 (PG&E/Harrison).

94. The NTSB determined that a hydro test conducted at a pipe mill would have caused the pups to fail, and thus, was not what caused the ductile tear in pup 1. Ex. PG&E-1 at 2-9 (PG&E/Harrison).

95. Segment 180 may have been subject to a post-installation pressure test. Ex. PG&E-1 at 2-9 (PG&E/Harrison); R.T. 1084 (PG&E/Caligiuri). According to testimony by a former PG&E employee, he may have observed a hydro test on the Segment 180 relocation project. Ex. PG&E-1 at 2-9 (PG&E/Harrison).

96. Items specifically designed for use to hydro test pipe were purchased for the Segment 180 relocation job. Joint R.T. 413-14 (PG&E/Harrison).

97. Dr. Caligiuri identified a 1956 post-installation hydro test as the likely cause of the ductile tear, and no other plausible cause of the ductile tear on pup 1 has been identified. Ex. PG&E-1 at 3-16 (PG&E/Caligiuri); R.T. 1084 (PG&E/Caligiuri).

98. Dr. Caligiuri shared his conclusion with the NTSB; the NTSB found the conclusion credible. R.T. 1084-85 (PG&E/Caligiuri).

PG&E's Integrity Management Program

Data Gathering and Integration

99. PG&E's Integrity Management program follows the prescriptive process identified by ASME B31.8S. Ex. CPSD-1 at 28, 36 (CPSD/Stepanian).

100. Risk Management Procedure 06 (RMP- 06) provides the framework of PG&E's integrity management process. Ex. CPSD-1 at 29 (CPSD/Stepanian).

101. Data gathering and integration and integration is summarized in RMP-06. Ex. CPSD-1 at 29 (CPSD/Stepanian).

102. For the risk analysis process, PG&E has chosen pipeline attributes based upon available, verifiable information or information that can be obtained in a timely manner. Ex. CPSD-1 at 30 (CPSD/Stepanian).

103. PG&E's data gath ering process consists of two steps. In the first step, PG&E gathers and reviews pipeline attribute data from GIS, as well as other data sets relating to the environment around the pipeline. These data sets are integrated in GIS. Ex. PG&E-1c at 4-7 (PG&E/Keas).

104. PG&E's two -step data gathering process considered data elements identified in ASME B31.8S Appendix A. Ex. PG&E-1c at 4-8 (PG&E/Keas).

105. RMP-06 states: "In accordance with ASME B31.8S Appendix A, Section 5.2 , where data is missing, conservative assumptions are used when performing risk assessment." Ex. CPSD-1 at 31 (CPSD/Stepanian).

106. PG&E's practice, in the event it is missing data, has been to conduct additional data gathering to locate that information. If the data is unavailable, PG&E's practices have called for the use of conservative, assumed values aligned with

Company material procurement standards from the time period in which the pipe segment was installed. Ex. PG&E-1c at 4-8 (PG&E/Keas).

107. The NTSB's accident report found that PG&E used three different assumed SMYS values for pipe identified as "Grade B." Ex. CPSD-1 at 31 (CPSD/Stepanian).

108. The NTSB's accident report found that PG&E's GIS contained two segments with assumed SMYS values of 33,000 psig and 52,000 psig. Ex. CPSD-1 at 31 (CPSD/Stepanian)

109. RMP-06 identifies requirements for reviewing the quality and consistency of data. Ex. CPSD-1 at 31-32 (CPSD/Stepanian).

110. PG&E's GIS contained several segments, including Segment 180, with specifications indicating the pipe was 30-inch seamless pipe, even though there was no API-qualified domestic manufacturer of such pipe when the line was constructed. Ex. CPSD-1 at 32 (CPSD/Stepanian).

111. PG&E's GIS did not reflect the presence of six pups in Segment 180. Ex. CPSD-1 at 32 (CPSD/Stepanian).

112. Longitudinal seam defects were identified during radiography of girth welds during the 1948 construction of Line 132. Ex. CPSD-1 at 33 (CPSD/Stepanian).

113. PG&E's integrity management program was audited by CPSD and/or PHMSA twice prior to the San Bruno incident. Neither audit identified deficiencies in PG&E's data gathering and integration practices or other non-compliance with the integrity management regulations that form the basis of CPSD's current allegations. Ex. PG&E-1c at 4-11 to 4-12 (PG&E/Keas); Ex. PG&E-7 (Tab 4-13).

114. PG&E's procurement records for Line 132, Segment 180 reflected that PG&E ordered 30-inch DSAW pipe for the relocation project. Ex. PG&E-1c at 4-12 (PG&E/Keas).

<u>Threat Identification</u>

115. PG&E's integrity management procedures call for gathering the minimum data sets required by ASME B31.8S, Appendix A for identifying manufacturing threats. Ex. PG&E-1c at 4-13 (PG&E/Keas).

116. For Line 132, Segment 180, PG&E was able to gather the minimum data sets identified by ASME B31.8S, Appendix A for manufacturing threat identification from its GIS database. Ex. PG&E-1c at 4-13 to 4-14 (PG&E/Keas).

117. Both seamless pipe and DSAW are assigned a joint efficiency factor of 1.0 under federal regulations and ASME B31.8S. Ex. PG&E-1c at 4-14 (PG&E/Keas).

118. PG&E's 2004 B aseline Assessment Plan identified the following threats on various segments of Line 132: external corrosion, manufacturing and construction, third party damage, incorrect operations, and weather and outside force. Ex. CPSD-39.

119. PG&E's 2004 Baseline Asses sment Plan identified the following threats on Line 132, Segment 180: external corrosion, third party damage, incorrect operations, and weather and outside force. Ex. CPSD-39.

120. PG&E's 2004 Baseline Assessment Plan identified the following threats on Line 132, Segment 181: manufacturing, external corrosion, third party damage, incorrect operations, and weather and outside force. Ex. CPSD-39.

121. Prior to the San Bruno incident, PG&E engaged in a practice of increasing pressure from time to time on certain transmission lines to maintain operational flexibility. This practice has since been suspended. Ex. CPSD-40.

122. PG&E performed a pressure increase exercise on Line 132, including segments 180 and 181, on December 11, 2003. PG&E operated the line to approximately 400 psig. Ex. CPSD-1 at 44 (CPSD/Stepanian).

123. In 2004, PG&E's Baseline Assessment Plan identified Segment 180 as not having a manufacturing threat. Ex. CPSD-46.

124. In 2004, PG&E's Baseline Assessment Plan identified Segment 181 as having the manufacturing threat. This was because Segment 181 was installed in 1948, and was at least 50 years old at the time of the BAP. Ex. PG&E-1c at 4-16 (PG&E/Keas); Ex. CPSD-1 at 46 (CPSD/Stepanian).

125. PG&E's 2007 Baseline Assessment Plan (Rev. 3) identified both Segmen t 180 and 181 as having a manufacturing threat. This was because both were at least 50 years old at the time of the BAP. Ex. CPSD-1 at 48 (CPSD/Stepanian).

126. Line 132 experienced a pinhole leak in 1988 on a pipe segment constructed in 1948 from DSAW pipe. Ex. PG&E-1c at 4-14 (PG&E/Keas).

127. Prior to the San Bruno incident, DSAW pipe had not experienced seam failures, either on PG&E's system or industry-wide. Ex. PG&E-1c at 4-18 (PG&E/Keas).

128. Pipe procurement specifications for line pipe used in the 1948 construction of Line 132, as well as the 1956 relocation of Segment 180, called for the pipe to be subjected to a 90% SMYS mill hydro test. Ex. PG&E-1c at 4-19 (PG&E/Keas).

129. PG&E has not located any records identifying a long seam defect on Line 132 discovered in 1992. Ex. PG&E-1c at 4-20 (PG&E/Keas).

130. PG&E established its Integrity Management program in December 2004 when it filed its Baseline Assessment Plan. Ex. PG&E-1c at 4-24 (PG&E/Keas).

131. PG&E operated Line 132 to approximately 400 psig in 2008. Ex. PG&E-1c at 4-25 (PG&E/Keas).

Cyclic Fatigue

132. Prior to San Bruno, the natural gas transmission industry did not consider cyclic fatigue to be a threat on natural gas pipelines. Ex. PG&E-1c at 4-28 (PG&E/Keas).

133. Natural gas pipelines do not experience anywhere near the magnitude or frequency of pressure-cycle variations that liquid petroleum pipelines experience. Ex. PG&E-1c at 4-28 (PG&E/Keas).

134. The NTSB report found that cyclic fatigue was a factor in the failure of Segment 180. Ex. CPSD-1 at 50 (CPSD/Stepanian).

135. PG&E notified CPSD and PHMSA in 2005, and again in 2010, that it did not consider cyclic fatigue to be a threat to its transmission system due to the level of increases and frequency of pressure increases in its system. Ex. PG&E-1c at 4-30 (PG&E/Keas).

136. Neither PHMSA nor CPSD identified any concerns or violations of PG&E's threat identification process, including whether PG&E adequately evaluated cyclic fatigue, during 2005 or 2010 audits. Ex. PG&E-1c at 4-30 (PG&E/Keas); Ex. PG&E-7 (Tabs 4-13, 4-14, 4-25).

137. Applying the calculations of Dr. John F. Kiefner's 2007 paper to the pipe specifications for Line 132, as reflected in procurement records (30-inch diameter, 0.375-inch wall thickness, X-52 DSAW with a 90% SMYS mill hydro test) would result in an expected life of approximately 96 to 111 years. Ex. PG&E-1c at 4-31 (PG&E/Keas).

Segment 180 Recordkeeping; Brentwood Video

138. PG&E's records contain documents showing design, construction records and specifications for Segment 180. Joint R.T. 322-23, 329 (PG&E/Harrison); Ex. Joint-10 at HRG 0063; Ex. Joint-12.

139. PG&E had no records showing the existence of the six pups in Segment 180. Joint R.T. 324-25 (PG&E/Harrison).

140. PG&E was unable to identify the source of every piece of pipe in Segment 180. Joint R.T. 324-25 (PG&E/Harrison).

141. PG&E was unable to identify records that documented the source of the section of pipe that failed. Ex. PG&E-1 at 2-3 to 2-4 (PG&E/Harrison); Joint R.T. 324-25 (PG&E/Harrison).

142. Segment 180 was documented in PG&E's Pipeline Survey Sheet and GIS as being 30-inch diameter seamless steel pipe with a 0.375 inch nominal wall thickness and having a Specified Minimum Yield Strength (SMYS) of 42,000 psi, installed in 1956. Ex. CPSD-1 at 16, 64 (CPSD/Stepanian).

143. PG&E mistakenly identified Segment 180 as seamless and X42 pipe in Pipeline Survey Sheets and GIS because, when the Pipeline Survey Sheets were populated, the information was incorrectly derived from a 1956 journal voucher. Ex. CPSD-1 at 63-64 (CPSD/Stepanian); Ex. PG&E-1 at 7-3 (PG&E/Harrison).

144. It was later determined that the SMYS for most of Segment 180 was 52,000 psig. Ex. CPSD-1 at 16 (CPSD/Stepanian).

145. Substituting the correct information, X52, results in a higher (not lower) yield strength. Ex. PG&E-1 at 7-3 (PG&E/Harrison).

146. There is no indication that the data entry error regarding seamless pipe led to any decisions that impacted safety. Designation of pipe as a DSAW pipe yields the same longitudinal joint efficiency factor (1.0) as if the pipe had been seamless. 49 C.F.R. § 192.917; Ex. PG&E-1 at 4-14 (PG&E/Keas); Ex. PG&E-1 at 7-2 (PG&E/Harrison); Joint R.T. 992-93, 997-98, 1053-54 (PG&E/Keas).

147. PG&E has not purchased 30-inch pipe with less than a 1.0 joint factor. Joint R.T. 241 (PG&E/Harrison).

148. PG&E has not located documentation related to hydro testing of the ruptured segment of Line 132. Ex. CPSD-1 at 22 (CPSD/Stepanian); Ex. PG&E-1 at 2-7 to 2-10 (PG&E/Harrison).

149. Although PG&E has not located pressure test records for Segment 180, Segment 180 records suggest that there was a hydrostatic test on Segment 180. Joint R.T. 412-14 (PG&E/Harrison); Ex. PG&E-1 at 2-8 to 2-10 (PG&E/Harrison); Ex. PG&E-1 at 7-3 (PG&E/Harrison).

150. In the Records OII, CPSD alleges 14 violations related to Line 132, Segment 180 records. [redacted]

151. In the Records OII, CPSD alleges that, from 1974 through 2010, there was bad data in Pipeline Survey Sheets and GIS, resulting in violations of Public Utilities Code Section 451, as well as PG&E's internal policies requiring retention of engineering records. [redacted]

152. In the Records OII, CPSD alleges in that PG&E failed to create or retain construction records for the 1956 Segment 180 project in violation of Public Utilities Code Section 451 . [redacted]

153. In the Records OII, CPSD alleges that PG&E failed to retain pressure test records for Segment 180 in violation of Public Utilities Code Section 451, ASME B31.8, GO 112, GO 112A, and GO 112B . [redacted]

154. In the Records OII, CPSD alleges that PG&E is missing design and pressure test records in violation of Public Utilities Code Section 451, ASME B31.8, GO 112, GO 112A, and GO 112B, Public Utilities Act, Article II, Section 13(b), and PG&E's internal policies. [redacted]

155. In the Records OII, CPSD alleges that PG&E failed to attempt to preserve video recordings from security camera 6 in the Brentwood alternate gas control facility in violation of Commission Resolution L-403 and the Preservation Order from Commission Executive Director. [redacted]

156. CPSD's allegations regarding PG&E's recordkeeping and the Brentwood facility video recording in that San Bruno OII are duplicative of CPSD's allegations in the Records OII. [redacted]; Ex. CPSD-1 at 62-68 (CPSD/Stepanian).

157. No security video was recorded by Camera 6 at the Brentwood facility because the third-party contractor failed to configure the digital video recorder to activate recording on motion detection. Ex. PG&E-1 at 7-3 (Tab 7- 1); [redacted]

SCADA/Milpitas Terminal and the Events on September 9, 2010

SCADA System

158. A Supervisory Control and Data Acquisition system (SCADA) is a computerized system that has three primary areas of functionality: the data acquisition component, the supervisory control component, and the data analysis component. Ex. PG&E-1 at 9-3 (PG&E/Miesner); Ex. CPSD-1 at 70-72 (CPSD/Stepanian).

159. The SCADA system receives information about operating conditions on a pipeline system, such as pipeline pressures, flow rates and valve status, and presents the information to gas control room operators who can take various actions to control pipeline operations based on that information. Ex. PG&E-1 at 9-3 (PG&E/Miesner).

160. PG&E's Gas SCADA system was originally installed in 1986. In 2005, PG&E upgraded to an entirely new Gas SCADA system, including new hardware and operating software. This system was compatible with PG&E's new secure company-wide Operational Data Network. Installation of the new SCADA system was complete in September 2006, with the exception of several minor

items that were completed shortly thereafter. Ex. PG&E-1 at 8-2 to 8-3 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 72 (CPSD/Stepanian).

161. The current generation of SCADA used by PG&E is based on Citect software from Schneider Electric. Ex. CPSD-1 at 71 (CPSD/Stepanian).

162. As of September 2010, PG&E's SCADA system included monitoring and control capability at approximately 340 remote locations. At those locations, the system included a total of approximately 317 remote terminal units (RTUs) and 23 Programmable Logic Controllers (PLCs), which together provided the primary data collection, analysis and command functionality for Gas Control. Ex. PG&E-1 at 8-3 (PG&E/Kazimirsky/Slibsager).

163. In total, at these remote locations, PG&E's SCADA system utilized approximately 14,000 monitoring points, including 3,700 digital points providing information related to equipment status, 5,300 analog points providing pressure and flow data, and 5,000 calculated points providing second-level information based on inputs from the monitoring points. Ex. PG&E-1 at 8-3 (PG&E/Kazimirsky/Slibsager).

164. The system also included approximately 850 control/supervisory points through which Gas Control could directly control devices and equipment on the transmission system, such as opening or closing valves, adjusting set points, or turning a compressor on and off. Ex. PG&E-1 at 8-3 (PG&E/Kazimirsky/Slibsager).

165. Distances of 10 or 15 or more miles between SCADA monitoring points on natural gas transmission lines are common and consistent with industry norms. Ex. PG&E-1 at 9-4 (PG&E/Miesner).

166. In combination, these SCADA devices provided Gas Control comprehensive information regarding pipeline conditions, both in real time and archived in PG&E's SCADA historian, as well as remote control functionality. Ex. PG&E-1 at 8-3 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-5 to 9-7 (PG&E/Miesner).

167. In September 2010, PG&E's SCADA control system included approximately 300 automated valves. The majority of these valves are remotely controlled valves, which can be adjusted, opened or closed by gas system operators through SCADA communication. Ex. PG&E-1 at 8-3 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-6 (PG&E/Miesner).

168. PG&E's utilization of automated valves as of September 9, 2010 was consistent with industry norms. Ex. PG&E-1 at 9-6 (PG&E/Miesner).

169. PG&E is in the process of installing by the end of 2014 over 200 additional automated valves throughout its transmission system, along with corresponding SCADA monitoring and control capability. Ex. PG&E-1 at 8-17 to 8-19

(PG&E/Kazimirsky/Slibsager); Joint R.T. 195 (PG&E/Slibsager); R.T. 339-42 (PG&E/Almario).

170. PG&E is installing automatic shut off valves where its pipelines cross earthquake faults. Ex. PG&E-1 at 8-14 (PG&E/Kazimirsky/Slibsager); Joint R.T. 197, 207 (PG&E/Kazimirsky).

171. On September 9, 2010, PG&E's SCADA system was a capable system, consistent with industry norms, that made available to PG&E gas control operators the operational information and remote control functionality for safe and reliable gas transmission. Ex. PG&E-1 at 9-6 (PG&E/Miesner).

172. On September 9, 2010, PG&E's San Francisco Gas Control Room had five operator consoles from which PG&E's gas control room personnel monitored and controlled the gas transmission system. Ex. PG&E-1 at 9-6 (PG&E/Miesner).

173. Three consoles were manned by Gas System Operators. PG&E's Gas System Operators have primary daily responsibility to monitor and control PG&E's gas transmission system. Ex. PG&E-1 at 9-6 (PG&E/Miesner).

174. Two gas control room consoles were manned by Transmission Coordinators, who are responsible for establishing and overseeing gas delivery plans, as well as generally overseeing system operations. Ex. PG&E-1 at 9-6 (PG&E/Miesner).

175. At each of the five consoles, separate computer monitors provide operators access to PG&E's SCADA system, Geographic Information System, PG&E's intranet, and the Internet. Ex. PG&E-1 at 9-6 (PG&E/Miesner).

176. On September 9, 2010, PG&E's Gas Control Room was appropriately configured and eq uipped to enable PG&E's gas control operators to safely and reliably operate PG&E's gas transmission system. Ex. PG&E-1 at 9-6 (PG&E/Miesner).

177. Few American gas pipeline operators have adopted computational pipeline monitoring software. Ex. PG&E-1 at 9-11 to 9-12 (PG&E/Miesner).

178. Computational pipeline monitoring systems work well for leak detection on liquid pipelines but do not work well on natural gas pipelines due, among other reasons, to the numerous outputs contained on natural gas pipelines. Ex. PG&E-1 at 9-11 (PG&E/Miesner); R.T. 846-52 (PG&E/Miesner).

179. The primary real-time leak detection method employed by natural gas pipeline operators in the United States is SCADA monitoring by pipeline control room operators. Ex. PG&E-1 at 9-12 (PG&E/Miesner).

180. SCADA-based leak detection involves the SCADA system receiving information regarding gas pressure from pressure sensors along the operator's pipeline. The SCADA system is programmed to compare the pressures it receives to a range of acceptable values, predetermined by the pipeline operator. If the pressure goes

above or below the preset range of expected values, the system alerts the operator to the abnormal condition. When operators receive pressure deviation alarms, they will use the SCADA trending tools to help determine whether there is a leak, and if so, its size and location. Ex. PG&E-1 at 9-12 (PG&E/Miesner).

181. Like most of the natural gas transmission industry, PG&E utilized SCADA monitoring for leak detection at the time of the San Bruno accident. Ex. PG&E-1 at 9-12 (PG&E/Miesner).

182. PG&E's SCADA system, like all SCADA systems using wireless communication, occasionally experiences data interruptions that may temporarily result in potentially invalid or stale information being transmitted to gas system operators. Ex. PG&E-1 at 8-12 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-7 to 9-8 (PG&E/Miesner).

183. The SCADA system is programmed to automatically re-poll, i.e., re-scan, the signal from SCADA monitoring points to reestablish communication as effectively and quickly as possible. Ex. PG&E-1 at 8-12 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-7 to 9-8 (PG&E/Miesner).

184. Gas system operators evaluate the SCADA data they receive, and through methods such as trending multiple SCADA points up and downstream, analyze and determine operating conditions on the pipelines. Ex. PG&E-1 at 8-12 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-7 to 9-8 (PG&E/Miesner).

185. PG&E's gas control alarm policy allows 10 minutes for the Gas Operator to assess the situation and initiate an action, and an additional 10 minutes for follow up monitoring. Ex. CPSD-1 at 74 (CPSD/Stepanian).

Milpitas Terminal

186. Milpitas Terminal is one of the major regulation stations in the PG&E's gas transmission system. Although it is also the site of a local transmission maintenance headquarters, Milpitas Terminal is classified as an unmanned facility. Ex. PG&E-1 at 8-4 (PG&E/Kazimirsky/Slibsager).

187. Milpitas Terminal supplies gas to four outgoing gas transmission pipelines and a distribution feeder main (DFM). Outgoing Line 100 and the DFM serve the San Jose area, while Lines 101, 109 and 132 provide gas to the San Francisco Peninsula. Ex. PG&E-1 at 8-4 (PG&E/Kazimirsky/Slibsager).

188. Milpitas Terminal is controlled and monitored from PG&E's Gas Control Cen ter in San Francisco via the SCADA system, which provides real-time telemetric pipeline information to gas system operators through electronic data points located throughout PG&E's transmission system, including hundreds of points within Milpitas Terminal. Ex. PG&E-1 at 8-4 (PG&E/Kazimirsky/Slibsager).

189. PG&E rebuilt Milpitas Terminal in 1989. At that time, essentially the entire station was upgraded, replaced or built new. Ex. PG&E-1 at 8-10 (PG&E/Kazimirsky/Slibsager).

190. This included installation of new valves and valve vaults; installation of a comprehensive local control system; construction of the control building and the installation of the equipment inside it; installation of the back-up generators and the local control electrical system; and replacement of all the piping within Milpitas Terminal, from the point where the pipelines entered and exited the station. Ex. PG&E-1 at 8-10 to 8-11 (PG&E/Kazimirsky/Slibsager).

191. In 2002, PG&E upgraded Milpitas Terminal. At this time, the station PLCs were replaced with the latest technology, and the software upgraded. The valve controllers were also upgraded, as was the communication system between the PLCs and the controllers. Ex. PG&E-1 at 8-11 (PG&E/Kazimirsky/Slibsager).

192. The equipment in the station was also inspected and evaluated. PG&E tested the power supplies that failed on September 9, 2010, (PS-A and PS-B), and they did not show signs of degradation. Ex. PG&E-1 at 8-11 (PG&E/Kazimirsky/Slibsager).

193. On September 9, 2010, existing conditions with the equipment and control system at Milpitas Terminal did not constitute an unsafe or dangerous situation. Joint R.T. 113 (PG&E/Kazimirsky); *see* Joint R.T. 89, 92, 98, 109-10 (PG&E/Kazimirsky).

<u>September 9, 2010 Clearance and UPS Work at Milpitas Terminal</u>

194. On March 31, 2010, the Uninterruptible Power Supply (UPS) at Milpitas Terminal failed. Ex. CPSD-1 at 81 (CPSD/Stepanian); Joint R.T. 90 (PG&E/Kazimirsky).

195. The UPS system at Milpitas Terminal provides temporary power in the event of a loss of outside utility electrical power to equipment and systems where a short loss of power could impact station operations. Redundant standby generators installed at the site are designed to begin generating electrical power about 30 seconds after a loss of utility power. The UPS system bridges the time for the control system between the loss of utility power and the standby generator system coming online. Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager).

196. PG&E installed three mini-UPS units on April 1-2, 2010 to provide temporary power to the station electronic valve controllers in case of a power outage. On April 23, 2010 a fourth mini-UPS unit was installed for the station programmable logic controllers (PLCs). Ex. CPSD-1 at 81-82 (CPSD/Stepanian).

197. The Milpitas Terminal UPS had been in service since the 1980s with a three-phase system that was no longer needed. PG&E decided to replace the entire

UPS system with a new one. The lead-time to acquire and install an entirely new system could take several months. Ex. CPSD-1 at 81 (CPSD/Stepanian).

198. On September 9, 2010, as part of the project to replace the UPS at Milpitas Terminal, a PG&E construction team was disconnecting the remaining circuits connected to the electric distribution panel (UDP) to allow for replacement of the panel the following day. Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager).

199. PG&E Work Procedure (WP) 4100-10 issued August 2009 describes the two types of clearances depending on the work to be performed: (1) System Clearance and (2) Non-system Clearance. Ex. CPSD-1 at 82 (CPSD/Stepanian).

200. System clearances require authorization from PG&E's Gas System Operations. Ex. CPSD-1 at 82 (CPSD/Stepanian).

201. 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. Ex. CPSD-1 at 83 (CPSD/Stepanian).

202. PG&E's WP 4100 -10 requires a designated Clearance Supervisor for all clearances at all times. Clearance application MIL-10 -09 designated the Clearance Supervisor as "TBD". Ex. CPSD-1 at 83 (CPSD/Stepanian); Joint R.T. 142-43 (PG&E/Slibsager).

203. The checkbox on the clearance form that asks if normal function of the facility will be maintained was checked "No". The clearance application requires an explanation whenever this box is checked "No". There was no explanation provided on the clearance application as to how the work would affect normal function of Milpitas Terminal. Ex. CPSD-1 at 83 (CPSD/Stepanian); Joint R.T. 149-50 (PG&E/Slibsager).

204. Under the Sequence of Operations, the clearance application showed "Report On Daily and Report Off". It did not list any specific operations or communication steps to be reported to Gas Control. Ex. CPSD-1 at 83 (CPSD/Stepanian).

205. One of the steps taken during the UPS work at Milpitas Terminal on September 9, 2010, was switching the valve controllers to manual, which locks the valve to its current setting and disables Gas Control's ability to change the valve settings remotely. Ex. CPSD-1 at 83 (CPSD/Stepanian).

206. While the crew working at Milpitas Terminal repeatedly called Gas Control to keep them informed of what they were doing, the clearance application did not specifically set out the step of switching the valve controllers to manual. Ex. CPSD-1 at 83-84 (CPSD/Stepanian).

207. PG&E's Gas Control approved the clearance. Ex. CPSD-1 at 85 (CPSD/Stepanian).

208. PG&E WP 4100-10 requires the Clearance Supervisor to fill in any steps in a system clearance with the time, date, and initials of the person completing the step and file the clearance as completed. 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. Ex. CPSD-1 at 84 (CPSD/Stepanian).

209. PG&E did not fully comply with its clearance procedure, WP 4100-10, for the UPS work at Milpitas Terminal on September 9, 2010. Ex. CPSD-1 at 82-85 (CPSD/Stepanian); Ex. PG&E-1 at 8-8 (PG&E/Kazimirsky/Slibsager); Joint R.T. 136 (PG&E/Slibsager).

210. However, the field crew and gas system operators did follow good communication practices and took actions that focused on and furthered the safety of the work. Ex. PG&E-1 at 8-8 (PG&E/Kazimirsky/Slibsager); Joint R.T. 146-47 (PG&E/Slibsager).

211. Prior to beginning work, the crew at Milpitas Terminal conducted pre-work meetings (tailboards) on September 9, 2010, at which they addressed safety issues, discussed the day's project, and outlined the steps they would follow. Ex. PG&E-1 at 8-8 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-9 (NTSB Report) at 54; Ex. CPSD-12 at 10.

212. A pre-construction meeting had also been held in August. Ex. PG&E-1 at 8- 8
(PG&E/Kazimirsky/Slibsager).

213. When ready to begin, the lead gas control technician called Gas Control to alert them that the clearance was beginning. Ex. PG&E-1 at 8-8 to 8- 9
(PG&E/Kazimirsky/Slibsager).

214. As the work progressed, the gas control technician called Gas Control several more times. The purpose of these calls was to alert the gas system operators, prior to disconnecting the designated electrical equipment, that they were about to take a step in the project that could affect Gas Control's ability to monitor the system at Milpitas Terminal. Ex. PG&E-1 at 8-8 to 8- 9
(PG&E/Kazimirsky/Slibsager).

215. The field crew also took precautions when the steps they were taking on the project could potentially impact Gas Control's ability to control the system at Milpitas Terminal. Ex. PG&E-1 at 8-9 (PG&E/Kazimirsky/Slibsager).

216. Prior to moving the connections for the Genius Blocks from the existing electrical panel to the temporary UPS device, the lead gas transmission technician switched the valve controllers into manual, after documenting the pressures at each controller. While it was not expected that disconnecting power to the Genius Blocks would impact the valve controllers, the crew put the controllers into manual as an added precaution. Ex. PG&E-1 at 8- 9
(PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 83 (CPSD/Stepanian).

217. Once the Genius Blocks were reconnected to the temporary UPS device, the gas transmission technician and the contract engineer put the controllers back into automatic and rechecked the pressures at each controller to confirm they were functioning properly and that no pressure impact had occurred. Ex. PG&E-1 at 8-9 (PG&E/Kazimirsky/Slibsager).

218. While these precautions were not detailed in the written clearance, they were communicated to Gas Control prior to and after the actions were completed. Ex. PG&E-1 at 8-9 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 84 (CPSD/Stepanian).

219. When the crew had completed the steps in the electrical work they planned for the day, at approximately 5 p.m., the control system at Milpitas Terminal was functioning and no problems were occurring. Ex. PG&E-1 at 8-9 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 86 (CPSD/Stepanian).

220. PG&E has revised its clearance policy and is implementing additional tools and training to make it more effective. Ex. PG&E-1 at 8-21 to 8-23 (PG&E/Kazimirsky/Slibsager).

221. Among other things, the revised clearance policy requires that clearance applications include written risk assessment and contingency planning for potential abnormal events. Ex. PG&E-1 at 8-15 to 8-16 (PG&E/Kazimirsky/Slibsager).

<u>The Power Supply Failure and Pressure Increase</u>

222. The work to replace the UPS at Milpitas Terminal on September 9, 2010, began at 2:46 p.m. Ex. CPSD-1 at 7, 86 (CPSD/Stepanian); Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager).

223. At approximately 5:22 p.m., the voltage output from two 24v power supplies, PS-A and PS-B, fluctuated. Ex. CPSD-1 at 7, 87 (CPSD/Stepanian); Ex. PG&E-1 at 8-5, 8-7 (PG&E/Kazimirsky/Slibsager).

224. Power supplies PS-A and PS-B provide power to many of the pressure sensor current loops at Milpitas Terminal. The pressure sensors provide pressure feedback to the valve controllers that modulate the pressure regulating valves to maintain pressure at the set point value. Ex. CPSD-1 at 79 (CPSD/Stepanian); Ex. PG&E-1 at 8-5 to 8-6 (PG&E/Kazimirsky/Slibsager).

225. When the voltage from the power supplies fluctuated, the pressure transmitters they powered sent zero or negative pressure readings to the valve controllers, which then acted as designed to command their respective regulator valves open. Ex. CPSD-1 at 7-8, 87 (CPSD/Stepanian); Ex. PG&E-1 at 8-5, 8-7 (PG&E/Kazimirsky/Slibsager).

226. When the pressure reached the established set point, the monitor valves operated as designed to limit the pressure increase and maintain pressure control. Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager).

227. CPSD acknowledged that the "evidence of those monitor valves reviewed by CPSD shows they functioned as intended." Ex. PG&E -1 at 8- 7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-5 (Tab 8-2).

228. The pressure on Line 132 leaving the Milpitas Terminal reached a high of 396 psig, measured manually. Ex. CPSD-1 at 8, 90 (CPSD/Stepanian).

229. Pressure went above the 386 psig monitor valve set point because the reaction time of a monitor valve has to be restricted to avoid the risk of oscillation. Ex. PG&E-1 at 9-14 (PG&E/Miesner).

230. The highest pressure recorded at an upstream location closest to Segment 180 just prior to the failure was determined to be 386 psig. Ex. CPSD-1 at 8 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 12.

231. During conditions in which the primary pressure regulating device fails, 49 C.F.R. section 192.201(a)(2)(i) requires that the pressure in a transmission pipeline not exceed the MAOP + 10%. Ex. CPSD-1 at 24 (CPSD/Stepanian).

232. At the time of the incident, the pressure on Line 132 did not exceed the maximum pressure allowed by code. The pressure on Line 132 did not exceed its MAOP of 400 psig. Ex. CPSD-1 at 24 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 12.

233. The pressure limiting system at Milpitas Terminal, and on Line 132, functioned properly on September 9, 2010, and maintained pressure control on Line 132 below both the established MAOP and the maximum pressure allowed by code, MAOP + 10%, 440 psig on Line 132. Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-13 to 9-14 (PG&E/Miesner); Ex. CPSD-1 at 24 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 12; Joint R.T. 193 (PG&E/Kazimirsky).

234. The redundant pressure limiting system at Milpitas Terminal is a safe and appropriate system for controlling gas pressure on the Peninsula transmission system pipelines. Ex. PG&E-1 at 9-14 (PG&E/Miesner); Joint R.T. 113, 193 (PG&E/Kazimirsky); *see* Joint R.T. 89, 92, 98, 109-10 (PG&E/Kazimirsky).

235. The pressure increase on Line 132 on September 9, 2010 would not have caused a non-defective pipe to rupture. Ex. CPSD-1 at 91 (CPSD/Stepanian); Ex. CPSD-9 (NTSB Report) at 124; Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Joint R.T. 190, 193 (PG&E/Kazimirsky); Ex. PG&E-1 at 3-5 (PG&E/Caligiuri); Joint R.T. 188-89 (PG&E/Slibsager).

236. The pressure increase at Milpitas Terminal was related to the Segment 180 rupture in that it exposed the defective pup despite never reaching or exceeding allowable pressure limits. Joint R.T. 193 (PG&E/Kazimirsky); Ex. PG&E-1 at 8-12 (PG&E/Kazimirsky/Slibsager).

237. Programming the PLC at Milpitas Terminal to disregard zero or negative pressure readings could still result in an unintended pressure increase because the corresponding valve would have to be locked in last position; if demand decreased downstream, pressure would rise and the redundant pressure limiting system would be required to limit pressure. Joint R.T. 131-33 (PG&E/Kazimirsky); Ex. PG&E-1 at 8-8 (PG&E/Kazimirsky/Slibsager).

238. Three of the valve controllers at Milpitas Terminal suffered a rare type of programming malfunction and the manufacturer had to be contacted to advise how to correct it. This malfunction is thought to have resulted from electrical connections being disconnected and reconnected during the troubleshooting at Milpitas Terminal. Ex. CPSD-1 at 88 (CPSD/Stepanian); Ex. PG&E-1 at 8-15 (PG&E/Kazimirsky/Slibsager); Joint R.T. 92-97 (PG&E/Kazimirsky).

239. The malfunction of these three valve controllers was not related to the cause of the pressure increase. Ex. CPSD-1 at 88 (CPSD/Stepanian); Ex. PG&E-1 at 8-15 (PG&E/Kazimirsky/Slibsager); Joint R.T. 92-97 (PG&E/Kazimirsky).

Gas Control's Response to Pressure Increase and Line Break

240. PS-A and PS-B failed, resulting in the pressure increase at Milpitas Terminal, at approximately 5:22 p.m. Ex. PG&E-1 at 8- 5 (PG&E/Kazimirsky/Slibsager); Ex. CPSD-1 at 87 (CPSD/Stepanian).

241. The SCADA system alerted gas control operators, who immediately recognized the pressure increase. Ex. CPSD-1 at 87 (CPSD/Stepanian); Ex. PG&E-1 at 8-5 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8 to 9-9 (PG&E/Miesner).

242. The loss of PS-A and PS-B rendered some of the data coming into Gas Control from SCADA monitoring points at Milpitas Terminal inaccurate or invalid, and resulted in numerous SCADA alarms being sent to Gas Control. Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-8 to 9-9 (PG&E/Miesner).

243. The gas control operators trended and analyzed the mixture of incoming SCADA information and alarms to determine and confirm actual operating conditions at Milpitas Terminal and downstream on the outgoing transmission pipelines. Ex. PG&E-1 at 9-8 to 9-9 (PG&E/Miesner).

244. Gas control operators also confirmed that the back-up pressure limiting system at Milpitas Terminal, or "monitor control," was working to stop the pressure from further increasing. Ex. PG&E-1 at 9-9 (PG&E/Miesner).

245. PG&E's gas control operators worke d with the field crew at Milpitas Terminal to attempt to identify the source of the pressure increase. Ex. PG&E-1 at 8- 6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner).

246. At 5:52 p.m., Gas Control remotely lowered the pressure on the pipelines coming in to Milpitas Terminal in order to ensure the gas pressure in Milpitas Terminal and on the outgoing pipelines would decrease. Ex. PG&E-1 at 8- 6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner); Joint R.T. 115 (PG&E/Slibsager).

247. At the time of the rupture (6:11 p.m.), gas control operators had for approximately 50 minutes been receiving and attempting to integrate and analyze a mixture of valid and invalid SCADA data and alarms. Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner).

248. Alarm management is an issue that confronts the industry as a whole, as reflected in the recently-effective Control Room Management regulations. Ex. PG&E-1 at 8-13 (PG&E/Kazimirsky/Slibsager).

249. The addition of redundant pressure data to the mixed information gas system operators were analyzing would not have clarified the situation, and could have added confusion. Ex. PG&E-1 at 8-13 to 8-14 (PG&E/Kazimirsky/Slibsager) ; Ex. PG&E-1 at 9-10 to 9-11 (PG&E/Miesner).

250. PG&E designed its SCADA displays to strike the appropriate balance between the amount and types of SCADA data that should be immediately available to gas system operators to provide them with a favorable environment to receive, analyze and respond to incoming information. Ex. PG&E-1 at 8-13 to 8-14 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-10 to 9-11 (PG&E/Miesner).

251. The volume of data that can be effectively received and utilized by gas system operators without creating the risk of information overload is finite and, as a general rule, presenting information that is redundant to information already available would be counterproductive. Ex. PG&E-1 at 8-13 to 8-14 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-10 to 9-11 (PG&E/Miesner).

252. At 6:15 p.m., the first low-low SCADA alarm from Martin Station, downstream from the rupture, was received. Ex. CPSD-1 at 108 (CPSD/Stepanian); Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9- 9 (PG&E/Miesner).

253. The low pressure SCADA alarms related to the Line 132 rupture became additional single data points in the mixture of valid and invalid information and alarms that gas control operators had been receiving since 5:22 p.m. Ex. CPSD-1 at 108 (CPSD/Stepanian); Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner).

254. PG&E's gas control operators first learned of a fire and possible explosion in the San Bruno area at 6:27 p.m. when they received a telephone call from PG&E's Concord Dispatch center. Ex. CPSD-1 at 108-109 (CPSD/Stepanian); Ex. PG&E-1 at 8-7 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner).

255. At 6:29 p.m., 2 minutes after first becoming aware of the fire in San Bruno, PG&E's gas control operators connected the reports of the fire with the SCADA low pressure alarms on Line 132 to determine that there had likely been a line break on Line 132. Ex. CPSD-1 at 109 (CPSD/Stepanian); Ex. PG&E-1 at 8- 6
(PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner).

256. Following the rupture, the gas system operators evaluated all of the inconsistent SCADA information to attempt to determine actual operating conditions and to avoid making an uninformed operational decision that could have created substantial and unpredictable adverse consequences and safety risks. Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager).

257. On September 9, 2010, the remote shut off valves that were available to PG&E's gas control operators to isolate the Line 132 rupture were located in Milpitas Terminal and Martin Station, approximately 46 miles apart. Ex. PG&E-1 at 9- 9
(PG&E/Miesner).

258. Because of the cross-ties between the three Peninsula transmission pipelines, gas control operators would have been required to close the valves at Milpitas Terminal for all three pipelines feeding the San Francisco Peninsula to prevent new gas from entering the system. Ex. PG&E-1 at 9-9 to 9-10 (PG&E/Miesner).

259. Taking that action would have created unintended and severe public safety risks to a large population. Ex. PG&E-1 at 8-6 (PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner).

260. An uncontrolled gas shut down puts critical facilities, such as hospitals and power generation plants, at risk, as well as putting at risk the people who rely on those facilities. An uncontrolled shut down also creates the risk of residual gas entering residences and other buildings after pilot lights and furnaces have gone out due to insufficient gas pressure. Large gas outages increase the likelihood that people will take self-help actions, such as using space heaters or attempting to relight pilot lights themselves, which can create disastrous results if gas has gotten into buildings due to the loss of pressure during an outage. Ex. PG&E-1 at 8- 6
(PG&E/Kazimirsky/Slibsager); Ex. PG&E-1 at 9-9 (PG&E/Miesner).

261. Shutting the valves at Milpitas Terminal and Martin Station would not have stopped the gas already in the pipeline system from continuing to escape through the rupture. Ex. PG&E-1 at 9-9 (PG&E/Miesner).

262. PG&E's gas control operators responded reasonably both prior to and after the Line 132 rupture. Ex. PG&E-1 at 9-8 to 9-10 (PG&E/Miesner); Joint R.T. 113-14, 116 (PG&E/Slibsager); R.T. 857, 859-62 (PG&E/Miesner).

263. As of September 9, 2010, PG&E did not have a policy specifically instructing gas control operators to contact 911 during an emergency event. Joint R.T. 121 (PG&E/Slibsager).

264. A rotation exercise from the primary Gas Operations Center in San Francisco to the alternate control center in Brentwood was scheduled in advance to take place that day during the second shift at 6:00 p.m. Ex. CPSD-1 at 95 (CPSD/Stepanian).

265. The 6:00 p.m. crew was already at the backup location but rather than risk a new crew taking over in the middle of an emergency, the crew that had already been on duty for 12 hours stayed in place in San Francisco while the backup crew drove back to San Francisco. Ex. CPSD-1 at 95-96 (CPSD/Stepanian).

Post-Incident Drug and Alcohol Testing

266. PG&E performed post-incident drug testing on three PG&E employees and one PG&E contractor working on the UPS Clearance at the Milpitas Terminal. Ex. CPSD-1 at 99 (CPSD/Stepanian).

267. The drug testing was administered by a third party independent laboratory on September 10, 2011 between 3:36 a.m. and 5:21 a.m. and all four individuals tested negative. Ex. CPSD-1 at 99 (CPSD/Stepanian).

268. The post-incident alcohol test of the same four individuals was performed on September 10, 2011 between 3:10 a.m. and 5:02 a.m. and all tested negative. Ex. CPSD-1 at 100 (CPSD/Stepanian).

269. 49 C.F.R. § 199.225 requires that post-incident alcohol testing be conducted at the latest within 8 hours of an incident, and if testing is not done within the first 2 hours, that the operator prepare "a record stating the reasons the test was not promptly administered." 49 C.F.R. § 199.225(a) ; Ex. CPSD-1 at 100 (CPSD/Stepanian).

270. PG&E did not conduct alcohol testing of the personnel working on the clearance at Milpitas Terminal within the time required by code. Ex. CPSD-1 at 100-01 (CPSD/Stepanian).

271. PG&E did not have records documenting the reason for the timing of performing the post-accident alcohol testing. Ex. CPSD-1 at 101 (CPSD/Stepanian).

Emergency Response

272. PG&E incorporates by reference the Findings of Facts above from the sections on "September 9, 2010 Line 132 Accident" and "Gas Control's Response to Pressure Increase and Line Break" as they are relevant to PG&E's Emergency Response.

273. PG&E had written procedures that provided for the prompt and effective response to an incident occurring near or directly involving a pipeline facility. Ex. PG&E-1 at 11-5 to 11-23 (PG&E/Bull); Ex. PG&E-39 (PG&E Company Gas Emergency Plan); Ex. PG&E-42 (PG&E Gas T&D Emergency Plan Manual).

274. CPSD audited PG&E's emergency response plans and procedures in 2009 and 2010 and deemed them to be satisfactory. Ex. PG&E-1 at 10-2, Ch. 10, Apps. A, B (PG&E/Almario).

275. [redacted]

276. PG&E's emergency response was rea sonable, adequate, effective and prompt under the circumstances. R.T. 269 (PG&E/Almario); R.T. 415-16 (PG&E/Bull); R.T. 861-62 (PG&E/Miesner).

277. Two industry experts found that PG&E's emergency response was reasonable, adequate, effective and prompt. R.T. 415-16 (PG&E/Bull); R.T. 861-62 (PG&E/Miesner).

278. An expert on emergency response and emergency plans reviewed PG&E's response and plans and found that the plans provided for a prompt and effective response. R.T. 415-16 (PG&E/Bull); Ex. PG&E-1 at 11-25 to 11-28 (PG&E/Bull).

279. PG&E's written emergency response procedures at the time of the incident provide instructions for notifying the appropriate fire and police officials. Ex. PG&E-39 at 1-40, 1-47, IV-20; Ex. PG&E-1 at 11-24 to 11-25 (PG&E/Bull).

280. In response to an NTSB recommendation, PG&E has developed and implemented a revised 911 Notification Process pursuant to which Gas Control notifies the appropriate 911 agency when identified operational or field conditions occur. Ex. PG&E-1 at 10-10 (PG&E/Dickson). The NTSB deemed PG&E's revised 911 policy "acceptable" and as a "closed" item in response to NTSB's safety recommendation. Ex. PG&E-38 (NTSB Letter) at 2.

281. San Bruno Fire Chief Dennis Haag described the coordination between PG&E and the fire department as "great." Ex. PG&E-41 at 469.

282. In response to a CPSD post-incident recommendation, PG&E has developed and implemented first responder training regarding how to determine the source and nature of a fire, for example by considering the color of the flame and the type of smoke. Ex. PG&E-1 at 10-9 (PG&E/Dickson).

283. PG&E's gas control room's practice of having each of the gas operators maintain an overall view of the system, rather than monitor separate geographic regions, had benefits, such as creating an inherent check process through shared review

and enhancing collaboration on operational actions. Ex. PG&E-1 at 10-3 (PG&E/Almario); R.T. 290-92.

284. PG&E had written procedures for internal communications during an emergency event, including instructions, checklists and policies that describe the internal communications to be implemented in an emergency situation. Ex. PG&E-1 at 11-24 (PG&E/Bull); *see also id.* at 11-23 (PG&E/Bull).

<u>Budget and Safety Culture</u>

285. CPSD's expert Gary Harpster (Overland Consulting) and PG&E's expert Matthew O'Loughlin (The Brattle Group) conducted separate analyses to determine how PG&E's actual gas transmission and storage O&M expenses and capital expenditures compared to the levels included in authorized GT&S rates for the period from 1997 to 2010. Ex. CPSD-168 at 1-2; R.T. 56 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 1-2 (PG&E/O'Loughlin).

286. Four of the five GT&S rate cases covering 1997-2010 were resolved by settlement prior to a full decision by the Commission. The sole fully litigated case covered only one of the 14 years at issue – 2004. Ex. PG&E-15; Ex. PG&E-17; Ex. PG&E-19; Ex. PG&E-23; Ex. PG&E-27.

287. The GT&S rate case settlement agreements and related documents and the Commission decisions adopting the settlements do not explicitly set forth the O&M and capital amounts implicit in the authorized revenue requirements and rates for many of the years from 1997 to 2010. R.T. 66 (CPSD/Harpster); Ex. CPSD-168 at 2-8; R.T. 558-60 (PG&E/O'Loughlin).

288. The term "imputed adopted amounts" refers to the O&M and capex amounts implicitly provided for in revenue requirements and rates (i.e., where they are not explicitly stated in the decision). R.T. 61-62 (CPSD/Harpster).

289. Determining the imputed adopted GT&S O&M and capex amounts from 1997 to 2010 is complicated and requires a considerable amount of judgment. R.T. 57-58, 61-62 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 12-13 (PG&E/O'Loughlin); R.T. 558-60 (PG&E/O'Loughlin).

290. For many of the years, there is more than one potentially reasonable method for estimating the imputed adopted O&M and capex amounts. There is therefore not one correct imputed adopted amount for the entire period from 1997 to 2010, but rather a range of possible reasonable estimates of the imputed adopted amounts. R.T. 62-63 (CPSD/Harpster); R.T. 561 (PG&E/O'Loughlin).

291. Mr. Harpster found that PG&E spent $39.9 million less than the imputed adopted O&M amounts from 1997 to 2010. Ex. CPSD-170 at 7 (Table 3-2) (CPSD/Harpster).

292. Mr. Harpster found that PG&E spent $116.7 million less than the imputed adopted capital expenditures from 1997 to 2010. Ex. CPSD-170 at 8 (Table 3-3) (CPSD/Harpster).

293. Mr. O'Loughlin found that PG&E spent $43.1 million more than the imputed adopted O&M amounts from 1997 to 2010. Ex. PG&E-10, MPO-1 at 19 (PG&E/O'Loughlin).

294. Mr. O'Loughlin found that PG&E spent $261.5 million more than the imputed adopted capex amounts from 1997 to 2010. Ex. PG&E-10, MPO-1 at 43 (PG&E/O'Loughlin).

295. Mr. Harpster and Mr. O'Loughlin did not perform an analysis comparing the imputed adopted safety- related O&M expenses to PG&E's actual safety -related O&M costs for any of the period from 1997 to 2010. R.T. 83-84 (CPSD/Harpster); Ex. PG&E-10, MPO-3 (PG&E/O'Loughlin).

296. Mr. Harpster and Mr. O'Loughlin did not conduct an analysis compar ing the imputed adopted safety- related capital expenditures to PG&E's actual safety - related capital expenditures for the entire period from 1997 to 2010. R.T. 82-83 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 46 (PG&E/O'Loughlin).

297. Mr. Harpster found that PG&E spent $35 million more than the imputed adopted safety-related capex amounts for the only period in which he focused on safety-related costs – 2003 to 2010. Ex. CPSD-168 at 4-3 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 46 & n.88 (PG&E/O'Loughlin).

298. Mr. O'L oughlin found that PG&E spent $63 million more than the imputed adopted safety-related capex from 2004 to 2010. Ex. PG&E-10, MPO-1 at 46 (PG&E/O'Loughlin).

299. Mr. Harpster's methods for estimating the imputed adopted amounts did not closely adhere to the terms of the GT&S rate case settlements and the Commission decisions adopting them. R.T. 71, 138, 141-42, 144-46, 172, 174 (CPSD/Harpster); R.T. 560-61 (PG&E/O'Loughlin).

300. Mr. O'Loughlin estimated his imputed adopted amounts based on the settlement revenue requirements and the information that the settlement parties and the Commission had at the time the rates were set and approved. Ex. PG&E-10, MPO-1 at 13, 16- 17 (PG&E/O'Loughlin); R.T. 558 -59, 561-62 (PG&E/O'Loughlin).

301. The Gas Accord I settlement and related workpapers provided that O&M expenses would not be escalated from 1996 to 1997. Ex. PG&E-13 at 38; Ex. PG&E-14 at 98, 100, 115, 127, 139, 151, 163; R.T. 89-91 (CPSD/Harpster).

302. Mr. Harpster's imputed adopted O&M amounts for the Gas Accord I period assumed 2.5% escalation from 1996 to 1997. Ex. CPSD-168 at 2-9.

303. Mr. Harpster's imputed adopted O&M amounts for the Gas Accord I period are $8.7 million higher than they would have been if he had not escalated O&M costs from 1996 to 1997. Ex. PG&E-10, MPO-1 at 26 (PG&E/O'Loughlin); Ex. CPSD-170 at 31 (CPSD/Harpster).

304. The 2003 GT&S rate case settlement and the Commission decision approving the settlement provided that 2002 rates and other terms would be extended an additional year in 2003, but did not a adopt revenue requirement or specific O&M and capex amounts for 2003. Ex. PG&E-16 at 2; R.T. 66, 104-05 (CPSD/Harpster); Ex. PG&E-17 at 20 (Finding of Fact 5).

305. Mr. Harpster based his imputed adopted O&M and capex amounts for 2003 on a forecast that was created after the 2003 rate case settlement and the Commission decision setting rates for 2003. R.T. 110 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 31 (Figure 7) (PG&E/O'Loughlin).

306. Mr. Harpster's imputed adopted O&M amount for 2003 is approximately $10 million more than his imputed adopted O&M amount for 2002 and his imputed adopted capex amount for 2003 is approximately $25 million more than his imputed adopted amount for 2002. R.T. 108 (CPSD/Harpster); Ex. PG&E-18.

307. The Gas Accord III settlement, which set rates for 2005 through 2007, included detailed cost of service information for 2005 only. For 2006 and 2007, the agreement provided that the total revenue requirement would escalate at approximately 1.89% per year. R.T. 133-34 (CPSD/Harpster); Ex. CPSD-170 at 55 (CPSD/Harpster); Ex. PG&E-21 at 7.

308. Mr. Harpster did not follow a consistent method for his 2005-2007 imputed adopted amounts. He used a forecast created in 2007 for the Gas Accord IV proceeding for his 2007 imputed adopted capex amount. R.T. 138, 141-42, 144 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 52-53 & Figure 14 (PG&E/O'Loughlin).

309. The forecast that Mr. Harpster used for his 2007 imputed adopted capex amount was created years after the Gas Accord III settlement and the Commission's decision setting rates for 2005-2007. Ex. PG&E-10, MPO-1 at 52-53 & Figure 14 (PG&E/O'Loughlin).

310. Mr. Harpster's 2007 imputed adopted capex amount is approximately $37.5 million more than the capex amount included in rates for 2007. R.T. 139, 141-42, 144-45 (CPSD/Harpster); Ex. PG&E-22.

311. As the Commission previously found in its decision adopting the Gas Accord IV settlement, the settlement rates and revenue requirements were much lower for 2008 to 2010 than PG&E's litigation position forecast for those years. Ex. PG&E-27 at 26 (Finding of Fact 11). Specifically, the settlement revenue requirement was $11 million less than PG&E's litigation forecast revenue

requirement in 2008, $25 million less in 2009, and $39 million less in 2010. Ex. CPSD-168 at 2-10 (Table 2-4) (CPSD/Harpster); R.T. 160-61 (CPSD/Harpster).

312. Mr. Harpster's imputed adopted O&M amounts for 2008 to 2010 and his imputed adopted capex amounts for 2008 and 2009 are based on PG&E's litigation forecast. Ex. CPSD-168 at 2-8 (Table 2-3) (CPSD/Harpster).

313. Mr. Harpster used a forecast created in March 2010 for the Gas Accord V proceeding for his imputed adopted capex amount for 2010. Ex. CPSD-168 at 2-8 (Table 2-3) (CPSD/Harpster); R.T. 174 (CPSD/Harpster).

314. The forecast that he used for his 2010 imputed adopted capex amount was created years after the Gas Accord IV settlement and the Commission's decision adopting that settlement. R.T. 173-75 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 55 (Figure 15) (PG&E/O'Loughlin).

315. The 2010 forecast for the Gas Accord V proceeding that Mr. Harpster used to determine his imputed adopted capex amount for 2010 does not reflect the capex amount actually included in rates in 2010. R.T. 172 (CPSD/Harpster).

316. Mr. Harpster changed his method for determining his 2010 imputed adopted capex amount as compared to his other imputed adopted amounts during the Gas Accord IV period because he believed the imputed adopted amount would have been too low if he had followed a consistent approach for the entire rate case period. R.T. 171 (CPSD/Harpster).

317. Mr. Harpster selected a different source for his 2010 imputed adopted capex amount because he believed that PG&E's litigation forecast was too low when compared to PG&E's actual expenditures in that year. R.T. 179 (CPSD/Harpster).

318. Mr. Harpster's i mputed adopted capex amounts for 2008-2010 double count certain costs associated with the Lines 406 and 407 "adder" projects. R.T. 191 -93 (CPSD/Harpster); Ex. CPSD-170 at 77 (Table 10-7) (CPSD/Harpster).

319. A reduction from a litigation forecast revenue requirement to a settlement revenue requirement typically corresponds to a comparatively larger reduction from the litigation position capital forecast to the imputed adopted capex amount because the revenue requirement associated with one dollar of capex in the year it is spent is much less than one dollar. R.T. 130, 212-13 (CPSD/Harpster).

320. Mr. Harpster's decision to use PG&E's litigation forecast for Gas Accord IV rather than the settlement revenue requirements increased his imputed adopted O&M amounts for 2008 through 2010 by approximately $17.1 million. Ex. PG&E-10, MPO-1 at 32-33 (PG&E/O'Loughlin).

321. Mr. Harpster's decision to use PG&E's litigation forecast rather than the settlement revenue requirements to determine his 2008 and 2009 imputed adopted

capex amounts increased his imputed adopted capex amounts for those years by approximately $224 million. Ex. PG&E-10, MPO-1 at 53 (PG&E/O'Loughlin).

322. Mr. Harpster's decision to use a forecast from the Gas Accord V proceeding for his 2010 imputed adopted capex amount caused him to increase his imputed adopted amount by approximately $103 million as compared to the amount implicit in the settlement revenue requirement. Ex. PG&E-10, MPO-1 at 53 (PG&E/O'Loughlin).

323. Mr. Harpster's O&M comparison excludes customer -service-related O&M costs even though these were legitimate O&M costs that PG&E incurred in running the GT&S business. Ex. PG&E-10, MPO-1 at 36-39 (PG&E/O'Loughlin).

324. PG&E spent approximately $23 million more than the imputed adopted amounts for customer-service-related O&M costs from 1997 to 2010. Ex. PG&E-10, MPO-1 at 36-37 (PG&E/O'Loughlin).

325. Mr. Harpster used inconsistent methods for determining his imputed adopted amounts across and within rate case periods. Ex. CPSD-168 at 2-8 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 52-53 & Figure 14 (PG&E/O'Loughlin); R.T. 171, 179 (CPSD/Harpster).

326. Mr. Harpster found that GT&S generated $435 million more in revenues than PG&E needed to cover its actual GT&S costs and earn the authorized rate of return. Ex. CPSD-170 at 10 (CPSD/Harpster).

327. Mr. Harpster's calculation of the $435 million reflects the purported underspending on O&M and capex that he found. R.T. 209 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 82 (PG&E/O'Loughlin).

328. A significant portion of PG&E's GT&S revenues were "at risk," which meant that GT&S revenues could have fallen either above or below PG&E's revenue requirement. Ex. PG&E-10, MPO-1 at 62-63 (PG&E/O'Loughlin).

329. If external market conditions allowed, the Gas Accord pricing structure permitted PG&E to generate more revenues than its cost of service for its at-risk storage business. Ex. PG&E-10, MPO-1 at 77 (PG&E/O'Loughlin).

330. All of the GT&S rate cases from 1997 to 2010 continued the same basic pricing structure that allowed PG&E to generate more revenues than its unbundled storage revenue requirement if market conditions permitted. Ex. PG&E-10, MPO-1 at 73 (PG&E/O'Loughlin).

331. This treatment of unbundled storage by the Commission was not unique to PG&E. The Commission also allowed SoCalGas the opportunity to generate more revenues than needed to cover the cost of its unbundled storage service. Ex. PG&E-10, MPO-1 at 73-74 (PG&E/O'Loughlin).

332. PG&E's gas transmission and storage business generated more revenues than necessary to cover its actual cost of service (including earning the authorized rate of return) because of the strength of PG&E's at risk parking and lending revenues, not because of revenues from transmission or storage services provided to core customers. Ex. CPSD-170 at 134 (CPSD/Harpster); Ex. PG&E-10, MPO-1 at 68-70 (PG&E/O'Loughlin).

333. PG&E's market storage revenues, including parking and lending in particular, depended factors outside PG&E's control and therefore were uncertain. Ex. PG&E-10, MPO-1 at 70, 75- 76 (PG&E/O'Loughlin); R.T. 22 0-21 (CPSD/Harpster).

334. Because of external market conditions, PG&E was able to sell parking and lending services at quantities and prices that exceeded what was necessary to cover PG&E's market storage revenue requirement. Ex. PG&E -10, MPO-1 at 71 & Figure 21 (PG&E/O'Loughlin); R.T. 219-20 (CPSD/Harpster).

335. A regulated utility, particularly one using a forward test-year approach like PG&E, is unlikely to earn exactly the authorized ROE. Ex. PG&E-10, MPO-1 at 78 (PG&E/O'Loughlin); R.T. 237 (CPSD/Harpster).

336. The parties to the settlements were aware, or should have been aware, that PG&E's market storage business was generating revenues that exceeded its cost of service. Ex. PG&E-10, MPO- 1 at 73 n.116 (PG&E/O'Loughlin); Ex. PG&E - 11, MPO-35; Ex. CPSD-303; R.T. 659-62, 664 (PG&E/O'Loughlin).

337. GT&S viewed as a standalone entity was able to earn higher-than-authorized returns because of the strong revenues generated by its competitive market storage business, not because of any underspending on capital or O&M. Ex. PG&E-10, MPO-1 at 78 (PG&E/O'Loughlin).

338. Under the Commission's GT&S rate case decisions, PG&E was not required to spend all GT&S revenues within the GT&S business, but was permitted to use those revenues for other company purposes. Ex. CPSD-168 at 1-3 (CPSD/Harpster); Ex. CPSD-1 at 140 (CPSD/Stepanian).

339. PG&E allocates its financial resources through an enterprise-wide planning and budgeting process under which funding for a particular line of business is not limited to the specific revenues generated by that line of business. Ex. PG&E-10, MPO-1 at 79 (PG&E/O'Loughlin).

340. Budgets for PG&E's lines of business are set according to business and operational priorities rather than by explicitly allocating budgets by revenue source. Ex. PG&E-10, MPO-1 at 79 (PG&E/O'Loughlin).

341. The utility as a whole earned returns that were consistent with the Commission-authorized rates from 1999 to 2010. Ex. PG&E-10, MPO-1 at 80 (Figure 23) (PG&E/O'Loughlin); Ex. PG&E-11, MPO-38.

342. The rates of return of PG&E's combined gas business (gas distribution and GT&S) from 1999 to 2010 also were consistent with the Commission's authorized rates. Ex. PG&E-10, MPO-1 at 79-80 (PG&E/O'Loughlin).

343. Although it is not possible to trace how specific funds are used, the record indicates that PG&E used the GT&S revenues not spent within GT&S for other operational purposes, including for gas distribution. PG&E-10, MPO-1 at 163 (PG&E/O'Loughlin); R.T. 210-11 (CPSD/Harpster).

344. PG&E was not overly focused on financial performance. R.T. 974, 978 (PG&E/Yura).

345. Overland reviewed PG&E's gas transmission and storage business from a financial and ratemaking perspective, not from an operational or engineering one. Ex. CPSD-168 at 1-2 (CPSD/Harpster); R.T. 56 (CPSD/Harpster).

346. Overland does not have the necessary expertise to assess the safety implications of any budgeting or funding decisions. R.T. 237-38 (CPSD/Harpster).

347. Budget considerations did not affect integrity management assessments on Line 132 during 2008-2010. Ex. PG&E-1 at 12-3 to 12-4 (PG&E/Martinelli).

348. Budget considerations did not lead PG&E to defer a project to replace a portion of Line 132 between mile posts 42.13 and 43.55. Ex. PG&E-1 at 12-3 to 12- 4 (PG&E/Martinelli).

APPENDIX B

PROPOSED CONCLUSIONS OF LAW

Legal Issues of General Applicability

1. The appropriate standard of proof to be applied is clear and convincing evidence.

2. CPSD has the burden of proof as to every alleged legal violation.

3. Public Utilities Code Section 451 is a statute addressed to utility ratemaking and service reliability.

4. Section 451 cannot within the confines of the law be utilized as a broad pipeline safety provision.

5. As utilized by CPSD, Section 451 does not provide adequate notice regarding the conduct that it prohibits, and as such, penalizing PG&E's pri or conduct pursuant to Section 451 would not comport with state constitutional requirements.

6. CPSD is the only party that can properly allege violations of law against PG&E. Intervening parties can support in the factual record violations CPSD has alleged, but cannot lawfully assert separate violations of law.

7. PG&E's improvement initiatives after the September 9, 2010 incident do not signify that there were prior violations of law.

Segment 180 Construction

8. In 1956, PG&E installed defective pieces of pipe (the pups) in Segment 180.

9. In 1956, when Segment 180 was constructed, there were no legal requirements regarding the specified minimum yield strength of natural gas transmission pipe.

10. CPSD has not met its burden to establish that PG&E violated the law due to the yield strength of pipe installed on Segment 180.

11. In 1956, when Segment 180 was constructed, there were no legal requirements regarding particular wall thickness of pipe to be used in gas transmission pipelines.

12. CPSD has not met its burden to establish that PG&E violated the law with respect to the wall thickness of pipe installed on Segment 180.

13. In 1956, when Segment 180 was constructed, there were no legal requirements regarding weldability and girth welds on gas transmission pipelines.

14. ASA B31.1.8-1955 did not mandate the use of X-52 grade pipe or any particular strength pipe.

15. The fact that the pups in Segment 180 did not meet the 52,000 psig SMYS standard does not violate ASA B31.1.8-1955, Section 805.54.

16. CPSD has withdrawn its alleged violation regarding weldability under ASA B31.1.8-1955, Section 811.27.

17. CPSD has not met its burden to establish that the girth welds between the pups installed in Segment 180 deviated from any standard in violation of the law.

18. In 1956, when Segment 180 was constructed, there were no legal requirements regarding the minimum length of pipe installed in gas transmission pipelines.

19. CPSD has not met its burden to establish that PG&E violated the law with respect to the minimum length of pipe pieces installed on Segment 180.

20. In 1956, when Segment 180 was constructed, there were no legal requirements regarding pre-service hydro testing of natural gas transmission pipelines.

21. CPSD has not met its burden to establish that PG&E violated the law by failing to conduct a pre-service hydro test on Segment 180 in 1956.

22. In 1956, when Segment 180 was constructed, there were no legal requirements regarding the method by which an operator determined the maximum allowable operating pressure for gas transmission pipelines.

23. CPSD has not met its burden to establish that PG&E failed to appropriately establish the MAOP on Line 132, Segment 180, in violation of the law.

PG&E's Integrity Management Program

24. 49 C.F.R. § 192.917(b) states that to identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4.

25. Operators using a prescriptive integrity management program must follow the prescriptive processes in Appendix A to ASME B31.8S.

26. Appendix A to ASME B31.8S contains minimum data gathering requirements specific to each of the following threats: internal corrosion; external corrosion; stress corrosion cracking; manufacturing threat; construction threat; equipment threat; third party damage; incorrect operations; and weather and outside forces.

27. Not all data sets specified in Appendix A are applicable to each threat.

28. Under ASME B31.8S, Appendix A, gas transmission pipeline operators are not required to review leak records for purposes of determining the potential for a manufacturing threat.

29. CPSD has not met its burden of establishing that PG&E violated 49 C.F.R. §192.917(b) by not considering data relating to various longitudinal seam defects in its assessment of potential manufacturing defects on Line 132.

30. CPSD has not met its burden of establishing that PG&E failed to gather the minimum data sets identified in Appendix A to ASME B31.8S.

31. When an operator is missing data from one of the data sets specified in ASME B31.8S, Appendix A, conservative assumptions should be used.

32. In using assumptions in place of missing data, an operator should choose default values that conservatively reflect the values of other similar segments.

33. CPSD has not established that PG&E's use of assumed values in its GIS system failed to meet the requirements of the integrity management regulations or ASME B31.8S.

34. ASME B31.8S, Section 4.4 requires that operators establish a plan for reviewing and analyzing the data collected in connection with the integrity management data gathering requirements.

35. CPSD has not met its burden of proving that the presence of erroneous data in PG&E's GIS system indicates that PG&E failed to review and analyze its data as required by ASME B31.8S, Appendix A, Section 4.4 and the integrity management regulations.

36. 49 C.F.R. § 192.917(e)(2) mandates that operators evaluate whether cyclic fatigue poses a threat to their pipelines.

37. The integrity management regulations do not provide specific guidance as to what manner of evaluation satisfies the mandate that operators evaluate cyclic fatigue.

38. CPSD has not proven that, prior to the San Bruno incident, informed and explicit reliance on research sponsored by the Department of Transportation concluding that cyclic fatigue did not pose a meaningful threat to natural gas pipelines constituted a legally inadequate evaluation under the integrity management regulations.

39. CPSD has not met its burden of establishing that PG&E failed to evaluate its pipelines for cyclic fatigue as required by the integrity management regulations.

40. 49 C.F.R. § 192.917(a) states that an operator must identify and evaluate all potential threats to each covered pipeline segment.

41. 49 C.F.R. § 192.917(e)(3) mandates that if an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects.

42. CPSD has not established that Segment 181 of Line 132 was subject to a potentially unstable long-seam manufacturing threat.

43. CPSD has not established that PG&E violated 49 C.F.R. § 192.917(e)(3) by failing to prioritize Segment 181 of Line 132 for a long-seam integrity assessment.

44. CPSD has not established that PG&E violated 49 C.F.R. § 192.917(e)(3) by failing to prioritize Segment 180 of Line 132 for a long-seam integrity assessment.

45. 49 C.F.R. § 192.921(a) states that an operator must assess the integrity of its pipe segments by applying one or more of four enumerated methods, depending on the threats to which the covered segment is susceptible.

46. 49 C.F.R. § 192.921(a) provides that an operator must select the assessment method or methods best suited to address the threats identified to the pipe segment in question.

47. Direct assessment, the method selected by PG&E to assess Line 132, Segment 180, is one of the four assessment methods identified in 49 C.F.R. § 192.921(a).

48. CPSD has not met its burden of establishing that PG&E violated 49 C.F.R. § 192.921(a) by selecting direct assessment to assess the integrity of Line 132, Segment 180.

PG&E's Recordkeeping; Brentwood Video

49. ASA B31.1.8 (1955) was a voluntary industry standard without the force of law.

50. In 1956, when Segment 180 was constructed, there were no state or federal regulations regarding gas transmission pipeline construction recordkeeping.

51. CPSD has failed to establish that PG&E's recordkeeping with respect to Line 132, Segment 180 constituted a violation of ASA B31.1.8 (1955) or Public Utilities Code Section 451.

52. The failure of the security camera to record video at the backup gas control room in Brentwood is not a violation of Resolution No. L-403 and Public Utilities Code 702.

53. CPSD's recordkeeping allegations in the San Bruno OII (Ex. CPSD-1 at 69; CPSD-5 at 34-35) are duplicative of CPSD's allegations in the Records OII and are, accordingly, appropriately disregarded in the present proceeding.

PG&E's SCADA System and the Milpitas Terminal; DOT Alcohol Testing

54. On September 9, 2010, the pressure on Line 132 (and Segment 180) never reached or exceeded the established MAOP of 400 psig.

55. On September 9, 2010, the pressure on Line 132 (and Segment 180) never reached or exceeded the regulatory maximum during abnormal operations.

56. CPSD did not meet its burden to establish that conditions at Milpitas Terminal on September 9, 2010 constituted an unsafe condition in violation of law.

57. CPSD failed to establish that PG&E's SCADA system on September 9, 2010 constituted an unsafe condition in violation of law.

58. PG&E's gas control operators responded reasonably and appropriately to the pressure increase and Line 132 rupture on September 9, 2010.

59. CPSD has not established that the actions of PG&E's gas control operators on September 9, 2010 violated any applicable law.

60. CPSD has failed to identify any regulation or code on which it can properly base alleged violations relating to "conditions" on PG&E's SCADA system and at Milpitas Terminal: CPSD conceded that "There are no specific requirements in the federal or state codes which address" the conditions it claims violated the law. Ex. CPSD-1 at 99 (CPSD/Stepanian).

61. PG&E violated 49 C.F.R. § 192.13(c) by failing to follow its written clearance policy and procedure for the electrical work at Milpitas Terminal on September 9, 2010.

62. PG&E violated 49 C.F.R. § 199.225 by failing to test the personnel at Milpitas Terminal for alcohol within the time required by code, and by not having a record stating the reasons that the test was not administered promptly.

PG&E's Emergency Response

63. CPSD has not met its burden to establish that PG&E's emergency response on September 9, 2010 violated the law.

64. At the time of the San Bruno accident, there were no federal or California regulations or laws establishing a standard for an operator's response time in a natural gas emergency.

65. 4 9 C.F.R. § 192.615(a)(3)(iii) addresses the required elements of a written emergency response plan, but does not mandate any particular time for emergency response.

66. On September 9, 2010, PG&E's written emergency response plans complied with applicable law.

67. PG&E's emergency response plans contained each of the elements required by 49 C.F.R. § 192.615.

68. 49 C.F.R. § 192.615(a)(8) provides for the establishment of a written procedure, but does not require that gas control operators contact 911 during an emergency.

69. CPSD has not established that PG&E violated any applicable law because its gas control operators did not contact 911 during the emergency response on September 9, 2010.

70. PG&E complied with 49 C.F.R. § 192.615(a)(8) by maintaining the requisite written procedures.

71. There is no legal requirement that PG&E have trained its first responders prior to September 9, 2010 to recognize the difference between fires fueled by low-pressure natural gas, high-pressure natural gas, or gasoline or jet fuel.

72. CPSD has not met its burden to prove that PG&E violated the law by not having a training program for its first responders prior to September 9, 2010 on how to recognize the difference between fires fueled by low-pressure natural gas, high-pressure natural gas, or gasoline or jet fuel.

73. On September 9, 2010, there was no legal requirement regarding the method an operator used to assign geographic area monitoring responsibilities in a gas control room.

74. PG&E did not violate the law by assigning overlapping geographic monitoring responsibilities in its gas control room.

PG&E's Safety Culture and Financial Priorities

75. Mr. Harpster erred in escalating his imputed adopted O&M amount in 1997.

76. Mr. Harpster's imputed adopted O&M and capex amounts for 2003 do not track the terms of the settlement agreement and are not a reasonable estimate of the amounts implicit in rates in 2003.

77. Mr. Harpster's imputed adopted capex amount for 2007 is not a reasonable estimate of the amount implicit in rates in 2007.

78. Mr. Harpster's imputed adopted amounts for 2008 to 2010 are not reasonable estimates of the amounts implicit in rates in those years.

79. Mr. Harpster's failure to closely follow the terms of the Gas Accord settlements in determining his imputed adopted amounts renders his estimates unreliable.

80. If Mr. Harpster had corrected the errors in his methodology identified in the findings of fact, he would have concluded that PG&E spent more, not less, than the imputed adopted O&M and capex amounts.

81. Mr. Harpster's decision to change methods for estimating the imputed adopted amounts both across and within rate cases gives the appearance that he was trying to reach a particular result rather than provide a reasonable estimate of the O&M and capex amounts in rates during 1997 to 2010. This reinforces the conclusion that Mr. Harpster's testimony does not provide a reliable estimate of PG&E's actual expenditures compared to the imputed adopted amounts.

82. Because Mr. Harpster's O&M comparison is unreasonable and unreliable, CPSD has not shown that PG&E spent less than the imputed adopted O&M amounts from 1997 to 2010.

83. Because Mr. Harpster's capex comparison is unreasonable and unreliable, CPSD has not shown that PG&E spent less than the imputed adopted capex amounts from 1997 to 2010.

84. CPSD did not show that PG&E spent less than the imputed adopted O&M or capex amounts specifically for safety-related costs.

85. There is no basis for penalizing PG&E or drawing negative conclusions about whether it unduly emphasized financial performance based on its past spending on the GT&S business as compared to the capital and O&M amounts implicit in the GT&S authorized rates.

86. There is no basis for penalizing PG&E or drawing negative conclusions about whether it unduly emphasized financial performance based on the revenues or returns earned by GT&S viewed as a standalone business.

87. CPSD has not shown that PG&E used revenues from the GT&S business for any purpose that reflects negatively on PG&E's safety culture.

88. In assessing whether PG&E unduly emphasized financial performance over safety, it is not appropriate to focus on the financial performance of a single part of PG&E's operations such as GT&S. The relevant question would be whether PG&E as a whole consistently earned significantly more than the authorized rate of return.

89. PG&E as a whole earned returns that were consistent with the rates of return authorized by the Commission.

90. The Overland Report fails to establish that PG&E's spending over time on the GT&S business had any negative safety effects.

91. Overland's overall conclusions about the safety implications of PG&E's spending on GT&S are unreliable because its conclusions about how PG&E's spending compared to the imputed adopted amounts are invalid and because it lacks the necessary expertise to make safety-related conclusions.

92. CPSD has not shown that budgetary or financial considerations affected the safety of Line 132.

93. CPSD has not shown that budgetary or financial considerations contributed to the San Bruno accident.

94. CPSD has not shown that PG&E valued profits over safety or that it placed undue emphasis on financial goals at the expense of safety.

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Ex. No.	Date		Description
	Ident.	Recd.	
PGE-1	9/25/12	1/15/13	Testimony of Witnesses
PGE-1a	1/14/13	1/15/13	Revised Testimony of Jane Yura
PGE-1b	1/14/13	1/15/13	Chapter 1, Introduction and Overview, Revised January 14, 2013.
PGE-1c	1/15/13	1/17/13 (conditionally)	Chapter 4 – Integrity Management (Revised)
PGE-2	9/25/12	1/17/13	Statement of Qualifications – Kris Keas
PGE-3	9/25/12	1/17/13	Exhibit 4-28 – Public
PGE-4	9/25/12	1/17/13	Updated Chapter 4 Exhibit List
PGE-5	9/25/12	1/15/13	Exhibits–Chapters 2, 7 and 8 –Public
PGE-5 (Tab 2-1)			Moody Engineering Company- Invoice # 8265 (1948)
PGE-5 (Tab 2-2)			PG&E Pipe Specifications for Pipe, Line 132
PGE-5 (Tab 2-3)			Moody Engineering Pipe Inspection Report (1949)
PGE-5 (Tab 2-4)			PG&E Pipe Specifications for Pipe, Line 153
PGE-5 (Tab 2-5)			NTSB Data Response NTSB_036-015A. Docket No. SA-534, Ex. 2-AF (January 13, 2011)
PGE-5 (Tab 2-6)			PG&E Response to GasTransmissionSystemRecordsOIl_DR_CPUC_003-Q11
PGE-5 (Tab 2-7)			Deposition of former PG&E employee, pp. 38-61
PGE-5 (Tab 7-1)			PG&E Response to GasTransmissionSystemRecordsOIl_DR_CPUC_008-Q16Revision
PGE-5 (Tab 7-2)			PG&E Response to GasTransmissionSystemRecordsOIl_DR_CPUC_043-Q05

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Ex. No.	Date		Description
	Ident.	Recd.	
PGE-5 (Tab 7-3)			PG&E Response to GasTransmissionSystemRecordsOIl_DR_CPUC_043-Q05Revision
PGE-5 (Tab 7-4)			PG&E Response to CPSD_DR_210
PGE-5 (Tab 8-1)			Transcript of Gas Control Log, September 9, 2010, pp. 17, 65, 68-72, 82, 86, 87, 240
PGE-5 (Tab 8-2)			CPSD Response to PGE-CPSD_005-Q07
PGE-6	9/25/12	1/17/13	Exhibits–Chapter 4, Vol.1-Public (Tabs 4-1 to 4-12)
PGE-6 (Tab 4-1)			Risk Management Procedure RMP-01: Provides an overview of the procedures that govern the risk management process
PGE-6 (Tab 4-2)			Risk Management Procedure RMP-02: External Corrosion Threat Algorithm
PGE-6 (Tab 4-3)			Risk Management Procedure RMP-03: Third Party Threat Algorithm
PGE-6 (Tab 4-4)			Risk Management Procedure RMP-04: Ground Movement and Natural Forces Threat Algorithm
PGE-6 (Tab 4-5)			Risk Management Procedure RMP-05: Design/Materials Threat Algorithm
PGE-6 (Tab 4-6)			Risk Management Procedure RMP-06: Gas Transmission Integrity Management Program
PGE-6 (Tab 4-7)			Risk Management Procedure RMP-08: Identification, Location, and Documentation of High Consequence Areas
PGE-6 (Tab 4-8)			Risk Management Procedure RMP-09: Procedure for External Corrosion Direct Assessment
PGE-6 (Tab 4-9)			Risk Management Procedures RMP-10: Procedure for Dry Gas Internal Corrosion Direct Assessment
PGE-6 (Tab 4-10)			Risk Management Procedure RMP-11: InLine Inspections Procedure

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PGE-6 (Tab 4-11)			Risk Management Procedure RMP-12: Pipeline Public Awareness Plan
PGE-6 (Tab 4-12)			Risk Management Procedure RMP-13: Procedure for stress corrosion cracking direct assessment
PGE-7	9/25/12	1/17/13	Exhibits–Chapter 4, Vol.2-Public (Tabs 4-13 to 4-27)
PGE-7 (Tab 4-13)			Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety, Gas Integrity Management Inspection Manual: Inspection Protocols with Results Forms, January 1, 2008) (2010 PHMSA Audit Protocol)
PGE-7 (Tab 4-14)			USRB, Summary of May 2010 Audit Findings, Pacific Gas & Electric Integrity Management Program, p. 3.]
PGE-7 (Tab 4-15)			Material and/or Equipment- Problem or Failure Report, Line 132
PGE-7 (Tab 4-16)			Letter from PG&E Technical and Ecological Services to PG&E Gas System Design, regarding Bunker Hill 30" transmission line failure (Mar. 1, 1989)
PGE-7 (Tab 4-17)			Moody Engineering Company - Invoice # 8265 (1948)
PGE-7 (Tab 4-18)			Moody Engineering Pipe Inspection Report (1949)
PGE-7 (Tab 4-19)			PG&E Pipe Specifications for Pipe, Line 153
PGE-7 (Tab 4-20)			PG&E Pipe Specifications for Pipe, Line 132
PGE-7 (Tab 4-21)			John Kiefner, Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, filed with U.S. Department of Transportation (April 2007)
PGE-7 (Tab 4-22)			Telephone Interview with Joe Joaquim, pp. 6-30
PGE-7 (Tab 4-23)			Kiefner and Rosenfeld, Effects of Pressure Cycles on Gas Pipelines (Sept. 17,2004)

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Ex. No.	Date		Description
	Ident.	Recd.	
PGE-7 (Tab 4-24)			Audit Protocol Matrix (2005), p. 12
PGE-7 (Tab 4-25)			Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety, Gas Integrity Management Inspection Manual: Inspection Protocols with Results Forms, July 1, 2005
PGE-7 (Tab 4-26)			Audit Protocol Matrix (2010), p. 6
PGE-7 (Tab 4-27)			Rosenfeld, Data Gaps in Pipeline Risk Assessment and the Role of ASME Codes and Standards (presented at PHMSAWorkshop) (Jul. 11, 2011)
PGE-8	9/25/12	1/15/13	Exhibits-Chapter 13, Vol.1-Public (Tabs 1-32)
PGE-8 (Tab 1)			Christopher John's Letter to NTSB (May 23, 2012)
PGE-8 (Tab 2)			NTSB Safety Recommendations. Update on PG&E's Actions (May 16, 2012)
PGE-8 (Tab 3)			MAOP Validation Project Status Report (July 11, 2011)
PGE-8 (Tab 4)			MAOP Validation Project Status Report (August 10, 2011)
PGE-8 (Tab 5)			MAOP Validation Project Status Report (September 12, 2011)
PGE-8 (Tab 6)			MAOP Validation Project Status Report (October 14, 2011)
PGE-8 (Tab 7)			MAOP Validation Project Status Report (February 7, 2012)
PGE-8 (Tab 8)			Testing Information
PGE-8 (Tab 9)			TURN Data Request 18-Q03 attch 1 - Testing Information

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Ex. No.	Date		Description
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PGE-8 (Tab 10)			Hydrostatic Pressure Testing Status Report (December 30, 2011)
PGE-8 (Tab 11)			Strength Testing Schedule
PGE-8 (Tab 12)			Strength Testing Schedule
PGE-8 (Tab 13)			Draft Gas Clearance Procedure
PGE-8 (Tab 14)			Draft Clearances at Manned Stations
PGE-8 (Tab 15)			Draft Non Clearance - Routine (NCR) Work
PGE-8 (Tab 16)			Draft Preparing an Application for Gas Clearance
PGE-8 (Tab 17)			Draft Placing Man on Line, Caution and Information Tags
PGE-8 (Tab 18)			Draft Testing Cleared Equipment to be Operational
PGE-8 (Tab 19)			Draft Transferring Clearance Supervisor Responsibilities
PGE-8 (Tab 20)			Draft Clearance Checklist for Control Room Personnel
PGE-8 (Tab 21)			Gas Control Room Process
PGE-8 (Tab 22)			Guidance Tailboard
PGE-8 (Tab 23)			Gas Emergency Response Plan - 2.6 Activation Process
PGE-8 (Tab 24)			Gas Emergency Response Plan - 2.2 PG&E Emergency Response System

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Ex. No.	Date		Description
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PGE-8 (Tab 25)			Gas Emergency Response Plan - Command Functions
PGE-8 (Tab 26)			Gas Emergency Response Plan - How PG&E Coordinates and Escalates Emergency Response
PGE-8 (Tab 27)			Gas Emergency Response Plan - Levels of Emergencies
PGE-8 (Tab 28)			PG&E's Utility Standard EMER - 6010S Training and Exercising Gas Emergency Response Plans
PGE-8 (Tab 29)			PG&E's Utility Standard EMER - 1001S Business Continuity and Emergency Operations Plan, Training, Exercise and Critique Standard
PGE-8 (Tab 30)			Gas Emergency Response Plan – Training
PGE-8 (Tab 31)			After Action Review Summary Report
PGE-8 (Tab 32)			Gas Emergency Plan - 1.7 Training, Assessment, and Exercise
PGE-9	9/25/12	1/15/13	Exhibits-Chapter 13, Vol.2-Public (Tabs 33-49)
PG&E-9 (Tab-33)			Chapter 4 Gas Transmission Valve Automation Program (PSEP)
PG&E-9 (Tab-34)			Chapter 4A Gas Transmission Value Automation Program (PSEP)
PG&E-9 (Tab-35)			DOT Testing Requirements
PG&E-9 (Tab-36)			Gas CPUC On Call Training/Refresher
PG&E-9 (Tab-37)			Training Roster
PG&E-9 (Tab-38)			PG&E's Drug-Free Workplace Program

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PG&E-9 (Tab-39)			Invite to Collection Site Training
PG&E-9 (Tab-40)			Annual Collector's Meeting Training
PG&E-9 (Tab-41)			Kiefner Final Report - Procedure for evaluating the stability of Mfg and construction defects
PG&E-9 (Tab-42)			Kiefner Final Report - Assessment of Potential Threat Interactions
PG&E-9 (Tab-43)			Kiefner Final Report - Mfg and Construction Threat Evaluation, Task 4
PG&E-9 (Tab-44)			Data Request 079_Q01
PG&E-9 (Tab-45)			Segment Analysis
PG&E-9 (Tab-46)			Data Request 079_Q02
PG&E-9 (Tab-47)			Data Request 079_Q03
PG&E-9 (Tab-48)			Segment Analysis
PG&E-9 (Tab-49)			Letter to Paul Clanon (January 30, 2012)
PGE-10	9/25/12	1/8/13	Testimony of Matthew P. O'Loughlin, Vol.1, Exhibits MPO-1 to MPO-7
PG&E-10 (MPO-1)			Prepared Testimony of Matthew P. O'Loughlin on behalf of Pacific Gas & Electric Company
PG&E-10 (MPO-2)			CV of Mr. O'Loughlin
PG&E-10 (MPO-3)			O'Loughlin Exhibit: O&M Expenses

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Ex. No.	Date		Description
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PG&E-10 (MPO-4)			O'Loughlin Exhibit: Capital Expenditures
PG&E-10 (MPO-5)			O'Loughlin Exhibit: Revenue Requirement
PG&E-10 (MPO-6)			O'Loughlin Exhibit: Comparison to PG&E Analysis
PG&E-10 (MPO-7)			O'Loughlin Exhibit: Revenue and Rate of Return
PGE-11	9/25/12	1/8/13	Testimony of Matthew P. O'Loughlin, Vol.2, Exhibits MPO-8 to MPO-63
PG&E-11 (MPO-8)			GT&S System Map
PG&E-11 (MPO-9)			Gas Accord I Settlement Agreement (excerpt)
PG&E-11 (MPO-10)			Gas Accord III Settlement Agreement Material (excerpts)
PG&E-11 (MPO-11)			Pacific Gas & Electric Company's Gas Accord II-2004 Prepared Testimony, Chapter 12, Cost of Service (excerpt)
PG&E-11 (MPO-12)			1999 GRC, Pacific Gas & Electric Company, Chapter 10B, Gas Department Customer Services Expenses: Gas Transmission
PG&E-11 (MPO-13)			Gas Accord I Settlement Agreement (excerpt) and Motion for Order Adopting Stipulation and Settlement Agreement and for Other Procedural Rulings (excerpt)
PG&E-11 (MPO-14)			Gas Accord I Workpapers (excerpts)
PG&E-11 (MPO-15)			Gas Accord I Extension Settlement Agreement (excerpt)
PG&E-11 (MPO-16)			PG&E's Response to Overland's Data Request OC-5

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Ex. No.	Date		Description
	Ident.	Recd.	
PG&E-11 (MPO-17)			Gas Accord IV Settlement Material (excerpts)
PG&E-11 (MPO-18)			PG&E 2008 Gas Transmission and Storage Rate Case, Testimony Supporting the Gas Accord IV Settlement, Steve Whelan (excerpt)
PG&E-11 (MPO-19)			TURN, Request for Award of Compensation For Substantial Contributions to Decision 07-09-045, A.07-03-012, November 19, 2007 (excerpt)
PG&E-11 (MPO-20)			Exhibit No. (PG&E-8), PG&E 1996 Test Year, Pipeline Expansion Report on Operations (excerpt)
PG&E-11 (MPO-21)			Gas Accord I Workpapers, PG&E Expansion Rate Estimation Model
PG&E-11 (MPO-22)			Exhibit No. (PG&E-7), PG&E 1996 Test Year, Chapter 9 (excerpt)
PG&E-11 (MPO-23)			D.95-12-055, Appendix C (excerpt)
PG&E-11 (MPO-24)			D.03-12-061, Attachment 1 (excerpt)
PG&E-11 (MPO-25)			Overland's Attachment 4-1
PG&E-11 (MPO-26)			PG&E's January 2003 testimony in the 2004 GT&S rate case, chapter 8, p. 8-30-32
PG&E-11 (MPO-27)			PG&E's Response to Overland's Data Request OC-296
PG&E-11 (MPO-28)			PG&E's Response to Overland's Data Request OC-296, Supp Attachment 1
PG&E-11 (MPO-29)			PG&E's Response to Overland's Data Request OC-38, Attachment 1
PG&E-11 (MPO-30)			D.03-12-061 (excerpt) and PG&E's Response to Overland's Data Request OC-167

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Ex. No.	Date		Description
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PG&E-11 (MPO-31)			Workpapers Supporting PG&E's June 11, 2004 Supplemental Testimony (excerpt)
PG&E-11 (MPO-32)			Motion for Order Adopting Stipulation and Settlement Agreement and for Other Procedural Rulings (excerpt)
PG&E-11 (MPO-33)			2004 GT&S Rate Case, Market Conditions Report, Appendix A (excerpt)
PG&E-11 (MPO-34)			Gas Accord I and Gas Accord III Workpapers (excerpts)
PG&E-11 (MPO-35)			PG&E Gas Accord III Extension Settlement Data Book (excerpt)
PG&E-11 (MPO-36)			PG&E 2008 Gas Transmission and Storage Rate Case, Testimony Supporting the Gas Accord IV Settlement, Steve Whelan (excerpt)
PG&E-11 (MPO-37)			PG&E's Planning and Budgeting Processes 2011 GRC (excerpt)
PG&E-11 (MPO-38)			Material Supporting Return Analysis
PG&E-11 (MPO-39)			2002 California Gas Report (excerpt)
PG&E-11 (MPO-40)			Pacific Gas & Electric Company's Gas Accord II-2004 Prepared Testimony, Chapter 9, Operating and Maintenance Expenses (excerpt) and Gas Accord II Workpapers (excerpt)
PG&E-11 (MPO-41)			PG&E's Response to Overland's Data Requests OC-140 and 141
PG&E-11 (MPO-42)			PG&E's Response to Overland's Data Request OC-83
PG&E-11 (MPO-43)			D.02-08-070 (excerpt), Gas Accord II Settlement Agreement (excerpt)
PG&E-11 (MPO-44)			ORA Report on the Results of Operations for Pacific Gas and Company Gas Transmission and Storage 2005 Rate Case (excerpt)

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PG&E-11 (MPO-45)			2011 GT&S Rate Case Application (excerpt)
PG&E-11 (MPO-46)			PG&E's 2004 Results of Operations ("RO") Model ("Gas Rate Base" Tab) & ("Gas Summary Proposed Multi" tab)
PG&E-11 (MPO-47)			Overland Workpaper 4-2
PG&E-11 (MPO-48)			Overland Workpaper 5-12
PG&E-11 (MPO-49)			2008 GT&S rate case Workpapers Supporting Litigation Revenue Requirements, Results of Operations (excerpt)
PG&E-11 (MPO-50)			PG&E's 2006 and 2009 FERC Form 2
PG&E-11 (MPO-51)			2008 GT&S Rate Case, Workpapers Supporting Capital Expenditures, March 15, 2007, p. 1,
PG&E-11 (MPO-52)			2011 GT&S Rate Case, Updated Workpapers Supporting Chapter 6 Capital Expenditures (excerpt)
PG&E-11 (MPO-53)			OC-09,OC-51: DR_OC_002-Q051-Atch01 and DR_OC_001-Q09-Atch02
PG&E-11 (MPO-54)			Overland Workpaper 5-1
PG&E-11 (MPO-55)			PG&E's Response to Overland's Data Request OC-200
PG&E-11 (MPO-56)			PG&E's Response to Overland's Data Request OC-130, Attachment 1
PG&E-11 (MPO-57)			PG&E's Response to Overland's Data Request OC-298
PG&E-11 (MPO-58)			Gas Accord III Settlement Agreement Materials, Exhibit 3
PG&E-11 (MPO-59)			PG&E's Response to Overland's Data Request OC-171

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PG&E-11 (MPO-60)			Gas Accord I Workpapers (excerpts)
PG&E-11 (MPO-61)			PG&E's 2004 RO Model (excerpt)
PG&E-11 (MPO-61)			PG&E's Response to Overland's Data Request OC-131
PG&E-11 (MPO-63)			PG&E's Response to Overland's Data Request OC-163
PGE-12	9/25/12	9/26/12	GT&S Rate Case History, 1997-2010
PGE-13	9/25/12	9/26/12	Gas Accord I Settlement Agreement (August 21, 1996)
PGE-14	9/25/12	9/26/12	Gas Accord I Workpapers (August 20, 1996)
PGE-15	9/25/12	9/26/12	Gas Accord I Decision (D.97-08-055, August 1, 1997)
PGE-16	9/25/12	9/26/12	Gas Accord II Settlement Agreement (2003 GT&S Rate Case, May 21, 2002)
PGE-17	9/25/12	9/26/12	Gas Accord II Decision (2003 GT&S Rate Case, D.02-08-070, August 22, 2002)
PGE-18	9/25/12	9/26/12	Overland 2003 Methodology
PGE-19	9/25/12	9/26/12	2004 GT&S Rate Case Decision Excerpt (D.03-12-061, December 18, 2003)
PGE-20	9/25/12	9/26/12	Gas Accord III Comparison Matrix (August 27, 2004)
PGE-21	9/25/12	9/26/12	Gas Accord III Settlement Agreement (August 27, 2004)
PGE-22	9/25/12	9/26/12	Overland's Imputed Adopted Capex Methodology in GA III
PGE-23	9/25/12	9/26/12	Gas Accord III Decision (D.04-12-050, December 16, 2004)
PGE-24	9/25/12	9/26/12	Gas Accord IV Workpapers Supporting Capital Expenditures and O&M Excerpt (March 15, 2007)
PGE-25	9/25/12	9/26/12	Gas Accord IV Application (March 15, 2007)
PGE-26	9/25/12	9/26/12	Gas Accord IV Settlement Agreement (March 15, 2007)

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PGE-27	9/25/12	9/26/12	Gas Accord IV Decision (D.07-09-045, September 20, 2007)
PGE-28	9/25/12	9/26/12	Gas Accord IV Testimony (March 15, 2007)
PGE-29	9/25/12	9/26/12	Excerpt from 2011 Gas Transmission and Storage Rate Case Updated Workpapers Supporting Chapter 6 Capital Expenditures
PGE-30	9/25/12	9/26/12	Gas Accord IV Capex Litigation Forecast vs. Actual Capex
PGE-31	9/26/12	9/26/12	Gas Accord V Litigation Forecast Revenue Requirement Compared to Settlement Revenue Requirement
PGE-32	9/26/12	9/26/12	Excerpt from Joint Testimony of Settlement Parties in Support of Gas Accord V Settlement Agreement
PGE-33	9/26/12	9/26/12	Gas Accord V Settlement Agreement
PGE-34	9/26/12	9/26/12	Gas Accord V Litigation Forecast Capex Compared to Settlement Capex
PGE-35	9/26/12	9/26/12	Gas Accord IV Litigation Forecast Revenue Requirement Compared to Settlement Revenue Requirement
PGE-36	9/26/12	9/26/12	Harpster Work Paper 5-7
PGE-37	9/26/12	9/26/12	Earnings Report Excerpt
PGE-38	9/26/12	10/1/12	August 29, 2012, Letter from the NTSB Regarding the Status of PG&E's Actions in Response to NTSB Recommendations
PGE-39	10/1/12	10/1/12	PG&E Company Gas Emergency Plan
PGE-40	10/1/12	10/1/12	NTSB San Bruno Event Timeline (NTSB Exhibit 2-DX)
PGE-41	10/1/12	10/1/12	NTSB Hearing Transcript, March 2, 2011 – Excerpt (Statement of Fire Chief Haag)
PGE-42	10/1/12	10/1/12	PG&E Gas T&D Emergency Plan Manual
PGE-43	1/14/13		Hall and Associates-End of Year Assessment of PG&E Safety Program (Public Version)
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PGE-46	1/15/13	1/15/13	Structural Welding Code - Steel
CPSD-1	9/25/12	1/15/13	CPSD Incident Investigation Report, September 9, 2012
CPSD-2	9/25/12	1/15/13	Errata to CPSD Incident Investigation Report
CPSD-3	9/25/12	1/15/13	Addendum to CPSD Report
CPSD-4	9/25/12	1/15/13	Testimony of Raffy Stepanian
CPSD-5	9/25/12		Rebuttal Testimony of Raffy Stepanian
CPSD-6	9/25/12	1/15/13	Declaration of Susan Bullis
CPSD-7	9/25/12	1/15/13	Declaration of Betti Magoolaghan
CPSD-8	9/25/12	1/15/13	Declaration of Robert Pelligrini
CPSD-9	9/25/12	1/15/13	NTSB Report on PG&E Natural Gas Transmission Pipeline Rupture and Fire San Bruno, CA September 9, 2010
CPSD-10	9/25/12	1/15/13	Report of the Independent Review Panel, San Bruno Explosion, June 24, 2011
CPSD-11	9/25/12	1/15/13	CPUC Examination Under Oath: Wayne Fong
CPSD-12	9/25/12	1/15/13	CPUC Examination Under Oath: Groppetti
CPSD-13	9/25/12	1/15/13	CPUC Examination Under Oath: Chris Baur
CPSD-14	9/25/12	1/15/13	CPUC Examination Under Oath: Peter Beck
CPSD-15	9/25/12	1/15/13	CPUC Examination Under Oath: Oscar Martinez
CPSD-16	9/25/12	1/15/13	NTSB SA-534, Exhibit No. 3-A (p.21)
CPSD-17	9/25/12	1/15/13	NTSB Exhibit 2C (p.24)
CPSD-18	9/25/12	1/15/13	CPUC 218-01 (p.32)
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CPSD-22	9/25/12	1/15/13	CPUC 194-08Atch01-35 (p.35)*
CPSD-23	9/25/12	1/15/13	CPUC 197-01Attch01 (p.35)
CPSD-24	9/25/12	1/15/13	CPUC 230-01 (p.35)
CPSD-25	9/25/12	1/15/13	NTSB Exhibit 2W (p.35)
CPSD-26	9/25/12	1/15/13	NTSB 080-001-S2 (p.35)
CPSD-27	9/25/12	1/15/13	NTSB Hearing Transcript for March 1, 2011 (p.39)
CPSD-28	9/25/12	1/15/13	NTSB 036-005-Amended-2, SA 534 Exhibit No. 2AI (p.40)
CPSD-29	9/25/12	1/15/13	CPUC 248-04 (p.41)
CPSD-30	9/25/12	1/15/13	RMP 06 (p.43)
CPSD-31	9/25/12	1/15/13	NTSB 004-005-Amended (p.44)
CPSD-32	9/25/12	1/15/13	NTSB 036-004 (SA 534 Exhibit 2M) (p.44)
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CPSD-34	9/25/12	1/15/13	CPUC 288-03 (p.45)
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CPSD-56	9/25/12	1/15/13	NTSB San Francisco Control Room Logs, Addendum to Exhibit 2Y (p.85, 87, 95, 109)*
CPSD-57	9/25/12	1/15/13	NTSB Interview of Construction Lead, September 16, 2010 (p.87)
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CPSD-59	9/25/12	1/15/13	NTSB Interview of Technical Crew Leader, September 16, 2010 (p.88)
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CPSD-140	9/25/12	1/15/13	CPUC 198-32Atch01 (Addendum)
CPSD-141	9/25/12	1/15/13	CPUC 198-32Atch5, 6 (Addendum)
CPSD-142	9/25/12	1/15/13	Utility Enforcement Branch memorandum RE: San Bruno Gas Pipeline Explosion: Pre-Incident Consumer Complaints
CPSD-143	9/25/12	1/15/13	Moody Inspection of 30-inch pipe Consolidated Western Steel, August 1949
CPSD-144	9/25/12	1/15/13	2010 Audit Protocol Response (FN 80)
CPSD-145	9/25/12	1/15/13	CPUC_154-02
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CPSD-148	9/25/12	1/15/13	CPUC_202-06
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CPSD-152	9/25/12	1/15/13	CPUC_240-02
CPSD-153	9/25/12	1/15/13	NTSB Exhibit 2CL
CPSD-154	9/25/12	1/15/13	NTSB_033-006*
CPSD-155	9/25/12	1/15/13	NTSB_036-008
CPSD-156	9/25/12	1/15/13	Deposition of Robert Jefferies*
CPSD-157	9/25/12	1/15/13	PG&E Memo dated March 1, 1989, Re: "30" Transmission Line Failure"
CPSD-158	9/25/12	1/15/13	Table - Line 132, Milpitas to Martin unkno160wn or pre-1970 ERW pipe
CPSD-159	9/25/12	1/15/13	PG&E Email dated October 28, 2009, Re: "Linear Indications in L-132"
CPSD-160	9/25/12	1/15/13	Table - PG&E ECDA Assessments
CPSD-161	9/25/12	1/15/13	Control System Risk Assessment
CPSD-162	9/25/12		EXH 39 - PART 3 - TATEOSIAN, CHARLES Vol. I 1-13-23-4*
CPSD-163	9/25/12		EXH 40 - TATEOSIAN, CHARLES Vol. II 1-16-12*
CPSD-164	9/25/12		EXH 41 - TATEOSIAN, CHARLES Vol. III 3-21-12*
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CPSD-166	9/25/12		EXH 39 - PART 2 - TATEOSIAN, CHARLES Vol. I 1-13-23-3*
CPSD-167	9/25/12		EXH 42 - TATEOSIAN, CHARLES Vol. IV 4-12-12*
CPSD-168	9/25/12	1/15/13	Overland Consulting Focused Audit of PG&E Gas Transmission Pipeline Safety-Related Expenditures for the Period 1996-2010

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CPSD-171	9/25/12	1/15/13	OC-1 GAS ACCORD TESTIMONY*
CPSD-172	9/25/12	1/15/13	OC-2 GAS ACCORD WORKPAPERS
CPSD-173	9/25/12	1/15/13	OC-5 Results of Operations Model for the Gas Accord rates adopted in D.03-12-061*
CPSD-174	9/25/12	1/15/13	OC-16 Gas Accord O&M expenses by natural cost element and year for the period 1996 to 2010
CPSD-175	9/25/12	1/15/13	OC-23 Schedule showing actual Gas Accord O&M for the years 1996 to 2010 by year and area/expense category
CPSD-176	9/25/12	1/15/13	OC-35 Number of year-end union employees in the organizations with direct responsibility for designing, operating, maintaining or constructing Gas Accord Assets by cost center and year for 1996 to 2010.
CPSD-177	9/25/12	1/15/13	OC-36 Number of year-end non-union (management) employees in the organizations with direct responsibility for designing, operating, maintaining or constructing Gas Accord Assets by cost center and year for 1996 to 2010.
CPSD-178	9/25/12	1/15/13	OC-38 Gas Accord capital expenditures by year
CPSD-179	9/25/12	1/15/13	OC-46-redacted Integrity Management Mileage Goal
CPSD-180	9/25/12	1/15/13	OC-50-redacted VOLUME 1, PG&E COMPARSION OF ADOPTED AND ACTUAL EXPENDITURES*
CPSD-181	9/25/12	1/15/13	OC-58 Actual operative date for each project in 2004, 2005 and 2008 test year Gas Transmission and Storage rate cases. Identify the projects that have been cancelled.
CPSD-182	9/25/12	1/15/13	OC-63 PG&E's Investment Planning Process Manual
CPSD-183	9/25/12	1/15/13	OC-64-redacted FUNDAMENTAL GAPS IN COMPETENCE
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CPSD-186	9/25/12	1/15/13	OC-68-redacted Gas transmission and storage Fall and Spring Program Review presentations made during 1996 through 2010.*
CPSD-187	9/25/12	1/15/13	OC-69 LOCAL TRANSMISSION MEMORANDUM OF UNDERSTANDING
CPSD-188	9/25/12	1/15/13	OC-79-redacted Presentations and reports made to the Gas Accord Steering Committee concerning capital expenditures and O&M expenses for the 2004 (Gas Accord II), 2005 (Gas Accord III) and 2008 (Gas Accord IV) test year rate applications.
CPSD-189	9/25/12	1/15/13	OC-82-redacted REVENUE MONITORING REPORTS, ATTACHMENTS 8 TO 19 (DECEMBER ONLY)*
CPSD-190	9/25/12	1/15/13	OC-83-redacted CGT INCOME STATEMENTS AND RATE BASE REPORTS*
CPSD-191	9/25/12	1/15/13	OC-84 GA SETTLEMENT ANALYSIS
CPSD-192	9/25/12	1/15/13	OC-85-redacted ATTACHMENT 3, JOB ESTIMATE FOR LINE 300B ILI PROJECT*
CPSD-193	9/25/12	1/15/13	OC-90-redacted ATTACHMENTS 9 AND 10 (INTERNAL AUDIT REPORTS)
CPSD-194	9/25/12	1/15/13	OC-92-redacted SUPPLEMENTAL ATTACH 1, GAS MATTERS EXECUTIVE STATUS REPORT, OCT 30, 2008. SUPPLEMENTAL, SUPPLEMENTAL ATTACH 1, GAS MATTERS EXECUTIVE STATUS REPORT, JULY 20, 2009, ATTACHMENT 2, GT&S ASSET ROADMAP, ATTACHMENT 4 (POST AUDIT PRESENTATION
CPSD-195	9/25/12	1/15/13	OC-95 CONTROL CENTER CONSOLIDATION
CPSD-196	9/25/12	1/15/13	OC-99 RISK MANAGEMENT PLANS
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CPSD-202	9/25/12	1/15/13	OC-161 LINE 401 EXCESS COST ADJUSTMENT
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CPSD-205	9/25/12	1/15/13	OC-200 ACTUAL REVENUE - CUSTOMER ACCESS CHARGE
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CPSD-209	9/25/12	1/15/13	OC-214 REPLACEMENT MILES
CPSD-210	9/25/12	1/15/13	OC-215 RECOAT MILES
CPSD-211	9/25/12	1/15/13	OC-216 TRANSMISSION DEFINITION INITIATIVE
CPSD-212	9/25/12	1/15/13	OC-222 ORIGNIAL AND SUPPLEMENTAL, MILES COMPARED TO 2004 BASELINE PLAN
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CPSD-214	9/25/12	1/15/13	OC-235 LEAK SURVEY
CPSD-215	9/25/12	1/15/13	OC-236 LEAK SURVEY
CPSD-216	9/25/12	1/15/13	OC-237 BACKBONE LEAK STATISTICS
CPSD-217	9/25/12	1/15/13	OC-238 LOCAL TRANSMISSION LIEAK STATISTICS
CPSD-218	9/25/12	1/15/13	OC-239 CORRECTIVE WORK ORDER BACKLOG

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Ex. No.	Date		Description
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CPSD-219	9/25/12	1/15/13	OC-241-redacted 2008 BUDGET REDUCTION
CPSD-220	9/25/12	1/15/13	OC-244 INTEGRITY MANAGEMENT HEADCOUNT
CPSD-221	9/25/12	1/15/13	OC-251 WORK ORDER TRACKING
CPSD-222	9/25/12	1/15/13	OC-254 TRANSMISSION DEFINITION INITIATIVE
CPSD-223	9/25/12	1/15/13	OC-256-redacted 2009 CAPITAL BUDGET TRANSFER*
CPSD-224	9/25/12	1/15/13	OC-257-redacted (1) Description and explanation of GT maintenance work rescheduled to 2010 from 2009 due to emergent issues, explanation of why the work was deferred and identification of specific projects that were deferred; and (2) description and explanation of deferrals.*
CPSD-225	9/25/12	1/15/13	OC-258 TOP 100 LISTS AND RM PROJECT TRACKING
CPSD-226	9/25/12	1/15/13	OC-259-redacted Description of work deferred from 2010 to 2011, reason and schedule. Internal documents that describe and explain the reasons for the deferrals.*
CPSD-227	9/25/12	1/15/13	OC-260-redacted Description of initiative to reschedule pipeline integrity management assessments to 2011 and 2012 to reduce 2010 costs, explanation of work rescheduling and the scope of work rescheduled and internal documents describing the initiative and the reasons for rescheduling the work.*
CPSD-228	9/25/12	1/15/13	OC-261-redacted Description and explanation of initiative to perform only mandated pipeline maintenance projects. Explanation of scope of reduced maintenance work. Description of canceled or deferred projects resulting from initiative; and internal documents describing initiative and the reasons for reducing maintenance work in 2010.
CPSD-229	9/25/12	1/15/13	OC-262-redacted Detail on why integrity management inspection methods were changed
CPSD-230	9/25/12	1/15/13	OC-264-redacted Detail on decision to change from ILI to ECDA*
CPSD-231	9/25/12	1/15/13	OC-267 2008 MAINTENANCE PROJECT BUDGET WAS ONLY 53 % OF REQUEST

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Ex. No.	Date		Description
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CPSD-232	9/25/12	1/15/13	OC-268-redacted Detail on benchmarking
CPSD-233	9/25/12	1/15/13	OC-274 Detail on MWC II COSTS BY PHASE
CPSD-234	9/25/12	1/15/13	OC-278 CORRECTIVE WORK ORDER BACKLOG*
CPSD-235	9/25/12	1/15/13	OC-292-redacted Details on change of miles on the STIP goal, and budget constraints documents that describe and explain of reduction.
CPSD-236	9/25/12	1/15/13	OC-293-redacted EXPONENT REGULATOR STATION AND VALVE AUDIT
CPSD-237	9/25/12	1/15/13	OC-296 PG&E O&M ANALYSIS
CPSD-238	9/25/12	1/15/13	OC-301-redacted CAPEX SPECIFIC PROJECTS
CPSD-239	9/25/12	1/15/13	OC-302-redacted CAPEX SPECIFIC PROJECTS
CPSD-240	9/25/12	1/15/13	OC-303-redacted CAPEX SPECIFIC PROJECTS*
CPSD-241	9/25/12	1/15/13	OC-304-redacted ASSESSMENT METHOD CHANGES (MILES)
CPSD-242	9/25/12	1/15/13	OC-305-redacted BX COSTS BY CATEGORY
CPSD-243	9/25/12	1/15/13	OC-308 2002 CAPITAL DEFERRALS
CPSD-244	9/25/12	1/15/13	OC-314 REVISED - 2008 BUDGET
CPSD-245	9/25/12	1/15/13	OC-319 BX COSTS B Y CATEGORY
CPSD-246	9/25/12	1/15/13	OC-320 RM PROJECT TRACKING (CAPITAL)
CPSD-247	9/25/12	1/15/13	OC-323-redacted LIST OF COST REDUCTION INITATIVES IMPLEMENTED
CPSD-248	9/25/12	1/15/13	OC-325-redacted MAINTENANCE PROJECT BUDGET
CPSD-249	9/25/12	1/15/13	OC-326 2010 HEADCOUNT REDUCTIONS
CPSD-250	9/25/12	1/15/13	OC-329 DISTRIBUTION HEADCOUNT
CPSD-251	9/25/12	1/15/13	OC-334 2003 REVENUES

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Ex. No.	Date		Description
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CPSD-252	9/25/12	1/15/13	OC-335 SYSTEM WIDE RIKS REDUCTION METRIC
CPSD-253	9/25/12	1/15/13	OC-336-redacted CAPEX SPECIFIC PROJECTS
CPSD-254	9/25/12	1/15/13	OC-337 CAPEX SPECIFIC PROJECTS
CPSD-255	9/25/12	1/15/13	OC-338 CAPEX SPECIFIC PROJECTS
CPSD-256	9/25/12	1/15/13	OC-339 CAPEX SPECIFIC PROJECTS
CPSD-257	9/25/12	1/15/13	OC-342 CORRECTIVE WORK ORDER BACKLOG
CPSD-258	9/25/12	1/15/13	OC-343 TOTAL IM MILES
CPSD-259	9/25/12	1/15/13	OC-344 INITIAL ASSESSMENT MILES
CPSD-260	9/25/12	1/15/13	OC-345 HYDRO TEST MILES
CPSD-261	9/25/12	1/15/13	OC-347-redacted 2010 BUDGET REQUEST BY PRIORITY CATEGORY
CPSD-262	9/25/12	1/15/13	OC-003-126*
CPSD-263	9/25/12	1/15/13	OC-003-127*
CPSD-264	9/25/12	1/15/13	OC-004-168*
CPSD-265	9/25/12	1/15/13	OC-005-185*
CPSD-266	9/25/12	1/15/13	OC-006-198*
CPSD-267	9/25/12	1/15/13	OC-007-203*
CPSD-268	9/25/12	1/15/13	OC-009-276*
CPSD-269	9/25/12	1/15/13	OC-009-286*
CPSD-270	9/25/12	1/15/13	OC-010-295*
CPSD-271	9/25/12	1/15/13	OCHP-2*
CPSD-272	9/25/12	1/15/13	OCHP-3*
CPSD-273	9/25/12	1/15/13	OCHP-4*

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CPSD-274	9/25/12	1/15/13	OCHP-5*
CPSD-275	9/25/12	1/15/13	OCHP-6*
CPSD-276	9/25/12	1/15/13	OCHP-11*
CPSD-277	9/25/12	1/15/13	OCHP-14*
CPSD-278	9/25/12	1/15/13	OCHP-18*
CPSD-279	9/25/12	1/15/13	OCHP-19*
CPSD-280	9/25/12	1/15/13	OCHP-20*
CPSD-281	9/25/12	1/15/13	OCHP-22*
CPSD-282	9/25/12	1/15/13	OCHP-23*
CPSD-283	9/25/12	1/15/13	OCHP-24*
CPSD-284	9/25/12	1/15/13	OCHP-25*
CPSD-285	9/25/12	1/15/13	OCHP-26*
CPSD-286	9/25/12	1/15/13	OCHP-31*
CPSD-287	9/25/12	1/15/13	OCHP-32*
CPSD-288	9/25/12	1/15/13	OCHP-34*
CPSD-289	9/25/12	1/15/13	OCHP-35*
CPSD-290	9/25/12	1/15/13	OCHP-36*
CPSD-291	9/25/12	1/15/13	OCHP-37*
CPSD-292	9/25/12	1/15/13	OCHP-38*
CPSD-293	9/25/12	1/15/13	OCHP-39*
CPSD-294	9/25/12	1/15/13	OCHP-43*
CPSD-295	9/25/12	1/15/13	OCHP-51*
CPSD-296	9/25/12	1/15/13	OCHP-52*

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CPSD-297	10/1/12	1/15/13	Data Request from the Records OII, "LegalDivision_001-Q08," attachments 154-156
CPSD-298	1/8/13	1/15/13	Comparison of Tables or Figures Re: Capital Expenditures from 1997-2010 from PG&E, Overland Consulting (Gary Harpster) and Matt O'Loughlin
CPSD-299	1/8/13	1/15/13	Comparison of Tables or Figures Re: O&M Expenses from 1997-2010 from PG&E, Overland Consulting (Gary Harpster) and Matt O'Loughlin
CPSD-300	1/8/13	1/15/13	CPUC D. 97-08-054 Adopting the Gas Accord
CPSD-301	1/8/13	1/15/13	Excerpts from Brattle Report CPUC v. El Paso, FERC Docket No. RP00-241-000
CPSD-302	1/8/13	1/15/13	Excerpt of PG&E Testimony in 2011 Rate Case
CPSD-303	1/8/13	1/15/13	Excerpts of CPSD Exhibit No. 291 PG&E Data Response to CPSD Data Request OCHP 002-37
CPSD-304	1/10/13	1/15/13	Complete Version of PG&E's Chapter 14 "PG&E's Planning and Budgeting Processes" in PG&E's 2011 General Rate Case Prepared Testimony, Exhibit (PG&E-8) General Report, in Contrast to Only the Title Page and First Page of Text in Exhibit No. PG&E-11 (MPO-37)
CPSD-305	1/15/13	1/15/13	NTSB Telephonic Interview of: Arthur "Mike" Massaglia, March 23, 2011
CPSD-306	1/15/13	1/15/13	Excerpts from the Deposition of Robert Jeffries 03-08-2012
CSB-1	9/25/12	1/15/13	Prepared Direct Testimony of Mayor Jim Ruane on Behalf of the City of San Bruno
CCSF-1	9/25/12	1/15/13	Direct Testimony of John Gawronski on behalf of the City and County of San Francisco
CCSF-2	10/1/12	10/1/12	NTSB Exhibit No. 2-B, Docket SA-534 PG&E Event Timeline

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CCSF-3	10/1/12	10/1/12	PG&E Response to CPUC Data Request 001-Q08 and attachments
CCSF-4	10/1/12	10/1/12	PG&E's Presentation at Pipeline Emergency Response Workshop September 26 & 27, 2011
CCSF-5	1/9/13	1/15/13	PG&E Response to TURN Data Request 002-Q06
CCSF-6	1/9/13	1/15/13	PG&E Data Response CCSF_001-Q12
CCSF-7	1/9/13	1/15/13	PG&E Response to CCSF Data Request 004-Q01 and Q05 in I.11-02-016
CCSF-8	1/9/13	1/15/13	NTSB Operations Chairman Factual Report Addendum, Dated 8/12/11
TURN-1	9/25/12	1/15/13	Prepared Direct Testimony of Marcel Hawiger
TURN-2	10/4/12	10/4/12	A.07-03-012, 2008 GTS, PG&E Workpaper for L132 replacement MP 42.13-43.5
TURN-3	10/4/12	10/4/12	A.09-09-013, 2011 GTS Rate Case, PG&E Workpaper for L132 replacement MP 42.13-43.5
TURN-4	10/4/12	10/4/12	I.12-01-007: PG&E Response to DR 002-35
TURN-5	10/4/12	10/4/12	I.12-01-007: PG&E Response to DR 002-33, Atch. 32
TURN-6	1/9/13	1/15/13	TURN Graph of PG&E Pressure Cycle Data for Line 300 (Backbone) and Line 132 (Local), Provided in DR 030-04 in R.11-02-019
TURN-7	1/9/13	1/15/13	PG&E, Gas Transmission and Storage 2005 Rate Case, Prepared Testimony, Ch02 (Admitted with Limited Purpose)
TURN-8	1/14/13	1/15/13	Data Request TURN_003-16 in I.12-01-007
TURN-9	1/15/13	1/15/13	Excerpt from AWS D1.1/D1.1M:2010 – Structural Welding Code-Steel

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Joint-01 (CCSF)	9/24/12	9/25/12	Excerpt from History of Line Pipe Manufacturing J.F. Keifner & E.B. Clark
Joint-02 (CCSF)	9/24/12	9/25/12	PG&E Response to CPUC Data Request 010-Q05 and Attachment 6
Joint-03 (CCSF)	9/24/12	9/25/12	PG&E Response to CPUC Data Request 016-01
Joint-04 (TURN)	10/2/12	10/5/12	PG&E Response to TURN Data Request 2-28
Joint-05 (TURN)	10/2/12	10/5/12	PG&E Response to TURN Data Request 2-29
Joint-06 (TURN)	10/2/12	10/5/12	PG&E Response to TURN Data Request 24-14 in R.11-02-019
Joint-07 (TURN)	10/2/12	10/5/12	PG&E Response to TURN Data Request 2-30
Joint-08 (CPSD)	10/3/12	10/5/12	PG&E Response Documents P3-24152 in I.11-02-016
Joint-09 (CPSD)	10/3/12	10/5/12	PG&E Response to CPSD Data Request 015 Question 001 attachment 692 in I.11-02-016
Joint-10 (CPSD)	10/3/12	10/5/12	Line Segment 180 Job File
Joint-11 (CPSD)	10/3/12	10/5/12	Drawing Number L.E. 12073
Joint-12 (CPSD)	10/3/12	10/5/12	Drawing Number 282764
Joint-13 (CPSD)	10/3/12	10/5/12	API Study 1104, 4th Edition, May, 1956, "Standard for Field Welding of Pipe Lines"
Joint-14 (CPSD)	10/3/12	10/5/12	MAOP Calculations
Joint-15 (PGE)	10/4/12	10/5/12	Drawing of Pipeline Tie-in – David Harrison (October 3, 2012)
Joint-16 (TURN)	10/4/12	10/5/12	SanBrunoExplosion-FireOII_DR_TURN_ORAL_REQUEST_Q01
Joint-17 (TURN)	10/4/12	10/5/12	Response to TURN Data Request 2-20
Joint-18 (TURN)	10/4/12	10/5/12	Response to TURN Data Request 2-21
Joint-19 (TURN)	10/4/12	10/5/12	Response to TURN Data Request 2-22

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Joint-20 (TURN)	10/4/12	10/5/12	Excerpt from NTSB Pipeline Accident Report Adopted August 30, 2011
Joint-21 (TURN)	10/4/12	10/5/12	Excerpt from Independent Review Panel Report dated June 24, 2011 (Aerial Photograph of San Bruno in 1956)
Joint-22 (TURN)	10/4/12	10/5/12	PG&E Response to TURN Data Request 2-1
Joint-23 (TURN)	10/4/12	10/5/12	PG&E Response to TURN Data Request 4-1
Joint-24 (CCSF)	10/4/12	Denied	San Francisco Chronicle April 22, 2012 Article: PG&E '89 Memo Noted Pipe's History of Weld Failure
Joint-25 (CCSF)	10/4/12	Denied	California Department of Toxic Substances Control, Draft Feasibility Study and Remedial Action Plan PG&E Decoto Pipeyard, August 2002
Joint-26 (CCSF)	10/4/12	10/5/12	PG&E Response to Data Request CCSF_002-Q01-10 and Attachment (Pressure Test Spreadsheet)
Joint-27 (TURN)	1/9/13	1/17/13	Excerpt from ASME B31.8S - 2004
Joint-28 (PG&E)	1/9/13	1/17/13	ASME B31.8S - 2004
Joint-29 (TURN)	1/9/13	1/17/13	PG&E Response to TURN Data Request 2-21
Joint-30 (CCSF)	1/9/13	1/17/13	Process Performance Improvement Consultants: Services
Joint-31 (CCSF)	1/9/13	1/17/13	PG&E Response to CCSF Data Requst 002-Q2 and 002-Q4 in I.12-01-007
Joint-32 (CCSF)	1/10/13		PG&E's 1984 Gas Pipeline Replacement Program
Joint-33 (CCSF)	1/10/13	1/17/13	Letter to Jane Yura Re: 2011 Risk Assessment Audit
Joint-34 (CCSF)	1/10/13	1/17/13	PG&E Response to CCSF Data Request 001-Q05 in I.12-01-007

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Joint-35 (CCSF)	1/10/13	1/17/13	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
Joint-36 (PGE)	1/10/13	1/17/13	Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels Compared to Code of Federal Regulations, 1st Edition, 2011
Joint-37 (PGE)	1/10/13	1/17/13	1983 Part 195 Final Rule Re: Radiography
Joint-38 (PGE)	1/10/13		2012 INGAA Study – Pipeline Miles by Longitudinal Seam Type and Leaks by Cause and Decades of Pipe Construction
Joint-39 (PGE)	1/10/13	1/17/13	PG&E's Response to General Order 112-E Audit of the PG&E's Integrity Management Program, October 17th, 2012
Joint-40 (CPSD)	1/15/13	1/17/13	Year 2004 Line 132 ECDA Survey
Joint-41 (CPSD)	1/16/13	1/17/13	Excerpt from the transcripts from the NTSB hearings held in 2011
Joint-42 (CPSD)	1/16/13	1/17/13	Excerpt from the INGAA report, pgs. E-6 to E-7
Joint-43 (CSB)	1/16/13	1/17/13	News Release: PG&E Statement on Final NTSB Report on San Bruno Accident
Joint-44 (CSB)	1/16/13	1/17/13	NTSB Safety Recommendation Letter, Dated September 26, 2011
Joint-45 (CCSF)	1/16/13	1/17/13	PG&E Response to CCSF DR 003-Q03R.11-02-019
Joint-46 (CCSF)	1/16/13	1/17/13	Cover sheet and summary page of PG&E 2004 Baseline Assessment Plan
Joint-47 (CCSF)	1/16/13	1/17/13	Cover Sheet and summary pages of PG&E 2010 Baseline Assessment Plan, Employee names redacted
Joint-48 (CCSF)	1/16/13	1/17/13	October 20, 2009 WKMC Review of Pipeline IMP Documents

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Joint-49 (PGE)	1/17/13	1/17/13	Integrity Characteristics of Vintage Pipelines
Joint-50 (PGE)	1/17/13	1/17/13	Cover Letter to May 2010 CPUC USRB Integrity Management Program Audit of PG&E
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

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Witness	Date	Page:Line	What was recorded	What should have been recorded
David Bull	10/01/2012	423:6	trading sessions that the company engages in	training sessions that the company engages in
David Harrison	10/03/2012	401:4	be none.	be known.
David Harrison	10/04/2012	515:3	I'm not staring to say anything more.	I'm not trying to say anything more.
David Harrison	10/04/2012	602:25	But usually you can tell the same	but usually you can tell the seam
David Harrison	10/04/2012	526:25	design station was the method	design basis was the method
Jane Yura	01/14/2013	906:14	the hotline, it will be -- is a very informal	the hotline, it will be -- is a very formal
Joel Dickson	10/01/2012	435:2	MNC	M&C
Joel Dickson	10/01/2012	435:9	event that they would trigger	event that would trigger
Joel Dickson	10/01/2012	439:13	public safety specialist who are fairly new	public safety specialists who are fairly new
Joel Dickson	10/01/2012	444:26	Control Center that were in	Control Center that we're in
Joel Dickson	10/01/2012	453:5	all elec- -- appliances	all electrical appliances
Joel Dickson	10/01/2012	454:9	This is the help, make more	This is to help, make more
Joel Dickson	10/01/2012	464:18	regulation station	regulation stations
John Kiefner	01/08/2013	681:25	thinking as the primary pipe, was 3-inch	thinking as the primary pipe, was 30-inch
John Kiefner	01/08/2013	704:24	assuming an operator pressure, as you can see	assuming a maximum operating pressure, as you can see
John Kiefner	01/08/2013	712:1	consider our manufacturing defect to be	consider our manufacturing defects to be

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Witness	Date	Page:Line	What was recorded	What should have been recorded
John Kiefner	01/08/2013	714:23	document or whether you need to consider	document for whether you need to consider
John Kiefner	01/08/2013	719:17	a threat. And that's key to a prior	a threat. And that's keyed to a prior
John Kiefner	01/08/2013	720:2	simply not, you know, much longer than the	simply, you know, much longer than the
John Kiefner	01/08/2013	724:10	And they can be very	And they can't be very
John Kiefner	01/09/2013	731:16	they had 30-inch 375 wall API Grade X52 pipe	they had 30-inch .375 wall API Grade X52 pipe
John Kiefner	01/09/2013	734:27	I mean, you offered	I mean, we offered
John Kiefner	01/09/2013	736:14	software to other people to do. Our other	software to other people to do. Other
John Kiefner	01/09/2013	742:2	beyond what we cannot conceive of it be, now	beyond what we cannot conceive it to be, now
John Kiefner	01/09/2013	752:7	1400 percent of SMYS pressure, not the	100 percent of SMYS pressure, not the
John Kiefner	01/09/2013	756:8	have a 30-inch, 375 wall, X52 pipeline like	have a 30-inch, .375 wall, X52 pipeline like
John Kiefner	01/09/2013	772:14	There was internal	There were internal
John Kiefner	01/09/2013	773:19	is 1.5 because of population density. So	is .5 because of population density. So
John Kiefner	01/09/2013	788:17	the 30-inch 375 wall X52. The six pups that	the 30-inch .375 wall X52. The six pups that
John Kiefner	01/09/2013	788:24	A The 30-inch 375 wall X52 pipe was	A The 30-inch .375 wall X52 pipe was
John Kiefner	01/09/2013	827:9	filed hydrostatic testing.	field hydrostatic testing.

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Witness	Date	Page:Line	What was recorded	What should have been recorded
Keith Slibsager	10/02/2012	116:23	Milpitas wasn't on monitor control	Milpitas was on monitor control
Kris Keas	01/15/2013	911:23	through ENM	through P&M
Kris Keas	01/15/2013	931:5	20048	2004
Kris Keas	01/16/2013	963:4	online	potential
Kris Keas	01/16/2013	964:24	pipeline settings,	pipeline segments,
Kris Keas	01/16/2013	974:10	ASME-B31.82	ASME B31.8S
Kris Keas	01/16/2013	992:17	our DIS had	our GIS had
Kris Keas	01/16/2013	1004:15	Louie,	Lui
Kris Keas	01/16/2013	1004:23	Louie,	Lui
Kris Keas	01/16/2013	1005:9	Louie,	Lui
Kris Keas	01/16/2013	1024:2	non-HVA	non-HCA
Kris Keas	01/16/2013	1028:24	seamless and say classified	seamless and say it's not correct
Kris Keas	01/16/2013	1031:9	manufacturing that hadn't in the 1950 that we	manufacturing that hadn't been in use in the 1950 that we
Kris Keas	01/17/2013	1148:17	RMI-04B	RMI-04
Kris Keas	01/17/2013	1154:21	differences of	different
Kris Keas	01/17/2013	1155:14	understanding what how our record	understanding how our record
Kris Keas	01/17/2013	1159:19	And Four	Class 4
Kris Keas	01/17/2013	1159:25	excessive	extensive
Kris Keas	01/17/2013	1170:17	Hairston's testimony,	Harrison's testimony,

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Witness	Date	Page:Line	What was recorded	What should have been recorded
Kris Keas	01/17/2013	1190:3	how they correct	how they correlate
Kris Keas	01/17/2013	1197:28	I'm all aware	I'm also aware
Kris Keas	01/17/2013	1202:10	our data sets we were	our data sets were
Kris Keas	01/17/2013	1202:13	have the algorithm	have the algorithm be
Kris Keas	01/17/2013	1204:21	Mobauer	Muhlbauer
Matt O'Laughlin	01/08/2013	542:22	Accord supplement was reached and a decision	Accord settlement was reached and a decision
Matt O'Laughlin	01/08/2013	545:27	different. In the middle when I was retained	different in the middle. When
Matt O'Laughlin	01/08/2013	546:12	for the highlights and the results that we	for the differences and the results that we
Matt O'Laughlin	01/08/2013	563:28	maintenance expenses and I strike two totals.	maintenance expenses and I include two totals.
Matt O'Laughlin	01/08/2013	566:8	underspending with -- and which I go to great	underspending with earnings and which I go to great
Matt O'Laughlin	01/08/2013	566:13	small amount of that underspending but	small amount of that to underspending but
Matt O'Laughlin	01/08/2013	566:14	the vast majority of that is due to store --	the vast majority of that is due to storage
Matt O'Laughlin	01/08/2013	571:14	that coming in from the north was Lines 400	that coming in from the north were Lines 400
Matt O'Laughlin	01/08/2013	572:20	that was relevant to the various gas accords.	that was relative to the various gas accords.
Matt O'Laughlin	01/08/2013	575:8	Upon capex, Line 401 was a brand	On capex, Line 401 was a brand
Matt O'Laughlin	01/08/2013	576:3	exiting long-term contracts covering	existing long-term contracts covering

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Transcript Corrections

Witness	Date	Page:Line	What was recorded	What should have been recorded
Matt O'Laughlin	01/08/2013	576:14	monopoly Figure 6. I just show	MPO-1 Figure 6. I just show
Matt O'Laughlin	01/08/2013	584:22	A Well, they don't see say it for the	A Well, they don't say it for the
Matt O'Laughlin	01/08/2013	589:6	clarity, so, much of that is in these	clarity, so, much of what is in these
Matt O'Laughlin	01/08/2013	589:7	as-available and off-system rates where while	as-available and off-system rates while
Matt O'Laughlin	01/08/2013	593:20	crossover ban quantities of gas	crossover ban, quantities of gas
Matt O'Laughlin	01/08/2013	595:9	second is that they mark	second is that they market
Matt O'Laughlin	01/08/2013	599:11	From my first perspective	First, from my perspective
Matt O'Laughlin	01/08/2013	599:25	pipelines: PG&E Gas Transwestern	pipelines: PG&E Gas Transmission
Matt O'Laughlin	01/08/2013	602:16	Gas Transmission Transwestern and	Gas Transmission, Transwestern and
Matt O'Laughlin	01/08/2013	610:22	that point, you're just speculating what	that point, you're just speculating as to what
Matt O'Laughlin	01/08/2013	611:7	parties' been negotiating	parties have been negotiating
Matt O'Laughlin	01/08/2013	615:18	revenue requirements in rates.	revenue requirements and rates.
Matt O'Laughlin	01/08/2013	629:7	but I believe it was part of their either	but I believe it was part of either their
Matt O'Laughlin	01/08/2013	644:1	bill the Operating Plan Steering	by the Operating Plan Steering
Matt O'Laughlin	01/08/2013	672:11	requirement of rates.	requirement or rates.

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Witness	Date	Page:Line	What was recorded	What should have been recorded
Matt O'Laughlin	01/08/2013	672:12	tell you what the appropriate amount level of	tell you what the appropriate amount or level of
Matt O'Laughlin	01/08/2013	674:9	return to recorded	return or recorded
Matt O'Laughlin	01/08/2013	676:1	in revenue requirements in rates.	in revenue requirements and rates.
Thomas Miesner	01/10/2013	846:20	You save a few have	You say a few have
Thomas Miesner	01/10/2013	846:21	When I say that a few, that	When I say that few, that
Thomas Miesner	01/10/2013	846:25	computation of leak detection	computational leak detection
Thomas Miesner	01/10/2013	848:1	computation of pipeline	computational pipeline
Thomas Miesner	01/10/2013	848:11	there that says down in this area certain	there that say down in this area certain
Thomas Miesner	01/10/2013	849:16	which means then if the	which means then that if the
Thomas Miesner	01/10/2013	851:28	some instruments will wonder back and for	some instruments will wander back and forth
Thomas Miesner	01/10/2013	852:22	They are always pressure waves	There are always pressure waves
Thomas Miesner	01/10/2013	861:1	an clog up the circuits	and clog up the circuits
Thomas Miesner	01/10/2013	861:15	there is a bunch of blind pressure	there is a bunch of built up pressure
Thomas Miesner	01/10/2013	862:20	names	flames