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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015 - 2017 (U39G).	Application 13-12-012 (Filed December 19, 2013)
And Related Matter.	Investigation 14-06-016

REPLY BRIEF OF THE OFFICE OF RATEPAYER ADVOCATES

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1 Overview

Pacific Gas and Electric Company (PG&E) makes two primary arguments in its Opening Brief: (1) making safety a "top priority" is a *new* requirement established by Senate Bill 705;[1] and (2) PG&E has met its burden of proof in this rate case and must receive the full rate increase it has requested to meet this new safety standard.

PG&E's position that "safety first" is a new standard when operating a high pressure natural gas transmission system is wrong. The Commission has based three San Bruno-related investigations and final decisions on the fact that PG&E had an obligation to comply with industry standards and to make safety its top priority for as long as it has been operating its pipeline system – and that it failed to exercise this responsibility over decades.[2] In this context, PG&E's argument that "safety first" is a new requirement demonstrates a troubling continued refusal to recognize its historic and ongoing responsibilities as a natural gas pipeline operator.

PG&E then uses this "new" safety standard to justify its "significant" rate increase.[3] In the process, PG&E omits significant language from the statutory "safety

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[1] See, e.g., PG&E Opening Brief, p. 1-7: ("SB 705 mandated for the first time that gas operators go beyond 'adequate' and develop and implement safety plans that are 'consistent with best practices in the gas industry,' and 'subject to … adequate funding by the Commission.' The CPUC has taken a leadership role in ensuring that gas operators implement SB 705's new safety mandates."). Senate Bill 705, codified at Public Utilities Code §§ 961 and 963.

[2] The San Bruno Investigations and decisions include: I.11-02-016 (Recordkeeping) and D.15-04-021; I.11-11-009 (Class Location) and D.15-04-022; I.12-01-007 (San Bruno Explosion) and D.15-04-0023; and the Fines and Remedies determination in all three investigations, D.15-04-024. These decisions affirm that PG&E's safety obligations are not "new." See, e.g., D.15-04-021, p. 44 ("California gas pipeline operators have had an ongoing duty to ensure the safe operations of their pipeline systems since 1912. Although there were no set industry standards for testing and retention of records until the ASME B.31.8 standards were established, in 1935, Pub. Util. Code § 451 (and Article II, Section 13(b) of the Public Utilities Act before that) clearly expected pipeline operators to test their pipeline systems and maintain the necessary records. PG&E's voluntary compliance of the ASME standards (including recordkeeping requirements) became mandatory with the adoption of GO 112.") and p. 49 ("PG&E has been on notice since 1909, as affirmed in the 1960 decision adopting GO 112, that it must at all times maintain safe facilities and operations.") and p. 52 ("To be clear, public utilities are not permitted to adopt anything other than safe operations and practices, even if they believe that rates approved by the Commission are inadequate."); see also similar remarks in D.15-04-023, p. 36.

[3] PG&E OB, p. 1-11 ("The significant increase sought in this case relative to previous GT&S rate cases reflects the fact that this is the first GT&S Rate Case filed since the legislature mandated that safety is the top priority, and that pipeline operators implement industry best practices for safety.").

first" mandate – language expressly intended to protect ratepayers from unreasonable requests, like the one presented in this case. Public Utilities Code § 963(b)(3) provides in full:

> It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph *consistent with the principle of just and reasonable cost-based rates.* (Emphases added).

In light of PG&E's troubling arguments in this case, and its failure to make affirmative factual showings in support of significant portions of its Application, the Commission should, among other things, vigilantly hold PG&E to the basic rules regarding the burden of proof in rate cases. The Commission should also establish annual requirements for critical work authorized in this rate case, and reporting obligations to ensure, among other things, that work is done, and at a reasonable cost.

The precursor to this rate case, the Pipeline Safety Enhancement Plan (PSEP) Decision (D.) 12-12-030 (the PSEP Decision), clearly articulated PG&E's burden of proof:

> As required by § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified," as provided in § 454.[4]
>
> The burden of proof is on PG&E to demonstrate that it is entitled to the relief sought in this proceeding, *including affirmatively establishing the reasonableness of all aspects of the application*.[5]
>
> The standard of proof that PG&E must meet is that of a preponderance of evidence, which means such evidence as, when weighed with that opposed to it, *has more convincing force and the greater probability of truth*.[6]

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[4] D.12-12-030, Conclusion of Law (COL) 2.

[5] D.12-12-030, COL 3.

[6] D.12-12-030, COL 4.

The PSEP Decision also identified specific work that PG&E must perform,[7] and imposed detailed reporting requirements.[8]

Holding PG&E accountable for its failure to meet its burden of proof and identifying specific work that PG&E must perform may not be popular. Among other things, PG&E has clearly signaled to the Commission that if it does not receive the full amount it requests in this rate case, the pace of its work will be impacted.[9] PG&E claims: "the revenues PG&E requests in this case are necessary to 'fully perform[] its duty of safe operations'."[10] However, the record demonstrates that PG&E seeks a rate increase more than double what it needs to perform the work it has identified for this rate case period.

Given the extremely inflated forecasts PG&E presents in this case, there is no question, especially regarding PG&E's proposed Hydrotest, Vintage Pipeline Replacement (VIPER) and Corrosion Control Program forecasts, that PG&E has failed to "affirmatively establish[] the reasonableness of all aspects of [its] application." Consequently, it has failed to show that its "new rate is justified."

In contrast, ORA shouldered the burden of proof (which it was not required to do) and not only shows specifically how many of PG&E's forecasts lack merit, but also proposes alternative forecasts for certain work, based on actual PSEP costs incurred between 2011 and 2013. ORA demonstrates the reasonableness of those forecasts by relying on evidence with "more convincing force and the greater probability of truth" than those proposed by PG&E. For all of these reasons, PG&E's showing should be rejected and ORA's forecasts adopted.

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[7] See, e.g., D.12-12-030, p. 3 ("This decision mandates pressure testing of 783 miles of pipeline, replacement of 186 miles of pipeline, installation of 228 automated valves, and upgrades to 199 miles of pipeline to allow for in-line inspection.")..

[8] D.12-12-030, OP 10 and Appendix D.

[9] See, e.g**.,** Motion Of Pacific Gas And Electric Company To Adopt A Proposed Procedural Schedule To Implement The San Bruno Penalty Decision, May 4, 2015, p. 1 (PG&E refers to "operational certainty" that a final GT&S decision will bring, suggesting that work priorities will be modified depending upon the rate increase authorized by the Commission.).

[10] PG&E OB, p. 1-2 quoting D.14-08-032, p. 20.

To ensure PG&E performs work the Commission deems critical, PG&E should be ordered to perform specific annual amounts of work, including, for example, hydrotesting, pipe replacement, in-line inspections (including any upgrades to facilitate), and corrosion control-related activities.[11] Finally, to ensure PG&E takes reasonable actions to control costs and implement efficiencies, and to provide necessary transparency regarding those costs, PG&E should be required to file quarterly reports disclosing all actual costs related to certain activities, such as hydrotesting and pipe replacement.[12] These quarterly reports should be similar in scope and content, with improvements, to the Quarterly Compliance Reports ordered in the PSEP Decision, and should be in a format that will provide a solid basis for future rate case analysis.[13] Further discussion regarding this reporting proposal is provided in Section 7.1.2 below.

1.1 Legal Issues

1.2 Policy Issues

1.2.1 PG&E Fails to Consider Affordability When Determining Relative Risk

PG&E argues that its request considers affordability, yet then asserts that if the Commission reduces PG&E's request, "it must recognize that less work may be done to reduce risk and that PG&E will need to reprioritize the work that can be performed during the Rate Case Period."[14] This assertion underscores one of the fundamental flaws of PG&E's risk analysis in this proceeding, the continued lack of any measure of risk reduction per dollar spent or forecast, discussed in Section 2 below.

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[11] See, e.g., D.12-12-030, p. 3; Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), § 3.6.

[12] See, e.g., D.12-12-030, Ordering Paragraph (OP) 10 and Attachment D; Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), § 3.7 and Ex. ORA-47 (Supplemental Testimony, Roberts) pp. 3-4 Q and A 6.

[13] ORA recommends, consistent with its stipulation with PG&E (Ex. Joint Stipulation-03, pp. 17-18), that this be considered as part of the workshop process. If the Commission does not adopt the workshop process proposed by PG&E and ORA, then ORA recommends quarterly reporting requirements for these programs consistent with the PSEP Quarterly Compliance Reports, as discussed in more detail in Section 7.1.2 below.

[14] PG&E OB, p. 1-3

Under the traditional forecast ratemaking treatment PG&E proposes for its safety spending, PG&E generally possesses the authority to reprioritize its spending, in a reasonable fashion and with a reasonable process, regardless of the specific spending level adopted, as ORA will discuss further in Section 3.1.6 below with respect to the cases PG&E itself cites. But PG&E does not have the authority to defer required safety work because the Commission adopted a revenue requirement PG&E alleges may not cover future safety costs and rate of return.

1.3 Summary of Revenue Requirement Recommendations

2 Safety and Risk Management Issues

PG&E claims that its showing in this case exceeds expectations established by the Commission in PG&E's 2014 General Rate Case.[15] ORA disagrees, given the continued lack of any connection between risk reduction and costs emphasized in D.14-08-032 and the Cycla and Liberty Reports in PG&E's current risk analysis they call a "risk assessment." PG&E filed this Application some nine months before the Commission reached a decision in the GRC, and even after the issuance of D.14-08-032, PG&E did not make any changes to its 2015 GT&S filing as a result of the 2014 GRC.[16] PG&E's changes to its relative risk analysis in this proceeding did not anticipate the criticisms and rejection of its proposal as not even comprising a "risk assessment" in D.14-08-032.

PG&E fails to meet the Commission's requirements that "expected benefits of proposed safety and security measures should justify their estimated costs" and "emphasis should be on those initiatives that deliver the optimal safety improvement in relation to the ratepayer dollars spent."[17] Furthermore PG&E's capability in quantifying data falls far short of where it needs to be.

As discussed by the Commission in its decision on PG&E's GRC:

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[15] PG&E OB, p. 2-5.

[16] Ex. ORA-61, p. A-47.

[17] PG&E OB, p. 2-5.

> PG&E 'overused' the 'safety' label. Liberty consultants found that much of what PG&E designates as 'safety' falls under what others consider to be baseline and reliability work. The Liberty Group observed regarding PG&E's analysis of costs and benefits that:
>
>> The GRC has generally not documented how expenditures to address safety and security are in proportion to or otherwise aligned with risks identified. [sic] PG&E has generally not demonstrated analytically that the benefits of proposed safety and risk mitigation measures justify their costs.[FN 8 – Exh. 168, Liberty Report at S-4.].
>
> Both the Cycla (gas distribution) and Liberty (electric) studies noted limitations in PG&E's showing as to the impact, if any, of its proposed activities on reducing safety risks. As Cycla explained, PG&E's GRC filing 'does not present a clear logical linkage between safety risk and the activities designed to control them.'[FN 9 – Exh. 167, Cycla Report at 61.]."[18]

Given the extensive and pervasive lack of information noted by Cycla and Liberty, and as amply demonstrated through discovery and testimony in this proceeding, PG&E still falls far short of meeting the Commission's expectations. The Commission should not accept PG&E's showing as adequate or as meeting expectations. Instead, the Commission should recognize that significant work is still needed before PG&E's risk management process is acceptable, and that such work must be performed according to the process established in D.14-12-025.

2.1 Expected benefits justifying costs

PG&E cannot quantify the benefits to justify the costs because "PG&E's tools cannot quantitatively measure the risk reduction. In some cases [the Risk Register] provides a qualitatively developed estimation of the risk reduction from mitigation measures based on available information and understanding at that time."[19]

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[18] D.14-08-032, pp. 23-24.

[19] Ex. ORA-61, pp. A-50 to A-51.

2.2 Optimal safety improvements in relation to the ratepayer dollars spent

PG&E failed to evaluate the number of people affected per threat for each asset family in the Risk Register.[20] Because PG&E is unable to determine the number of people affected, any calculation of the consequence of failure is suspect. Without a reasonable determination of the consequence of failure, the relation to improvement per ratepayer dollars spent is difficult, if not impossible to quantify. Indeed, PG&E even goes so far as to acknowledge that they (along with TURN and ORA) are unaware of basing risk reductions per dollar spent.[21]

3 Potential Shareholder Cost Responsibility Issues

PG&E's discussion of shareholder cost responsibility in Section 3.1 of its opening brief misrepresents Commission decisions in PG&E's past GRCs with respect to the definition of "deferred maintenance,"[22] and the purported limited circumstances in which a "disallowance" can be granted, in a reasonableness review or if "the utility is seeking rate recovery for work previously funded but 'deferred to improve the utility's financial position.'"[23] The Commission has noted with respect to a previous PG&E request of recovery for five different categories of "deferred maintenance" costs in a subsequent GRC that "'deferred' maintenance **cannot** be interpreted simply as activities that were previously funded in rate cases that PG&E subsequently decided not to do."[24] The Commission evaluates the utility on a standard of reasonableness for all its ratemaking decisions, including "[d]id management identify needed maintenance."[25] Moreover, because a utility improves its financial position if it defers maintenance for which it is responsible during one rate period to a subsequent rate period in which it requests costs

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[20] Ex. ORA-61, p. A-50.

[21] PG&E OB, p. 2-9.

[22] PG&E OB, p. 3-11.

[23] PG&E OB, p. 3-2, *citing* D.11-05-018, *mimeo*, p 27.

[24] D.83-12-068, 14 CPUC2d 15, 1983 Cal. PUC LEXIS 1156 at *121 (emphasis added). PG&E cited a reference to D.83-12-068 in D.11-05-018 on p.3-11 of its OB, as discussed below.

[25] D.83-12-068, 14 CPUC2d 15, 1983 Cal. PUC LEXIS 1156 at *130.

for such maintenance, under traditional forecast ratemaking such practices will always improve the utility's financial situation, so the standard again is whether or not a decision to defer otherwise necessary maintenance is reasonable, regardless of whether such maintenance was specifically deferred for the reason of improving the utility's financial position.

Consistent with the PSEP Decision (D.12-12-030), ORA recommends shareholder cost responsibility for hydrotesting pipes installed after December 31, 1955 as set forth in its Opening Brief in Section 7.4.5 and herein at Section 7.4.3. This includes disallowance of the forecast cost of the hydrotest where a pipe with missing records is replaced in lieu of hydrotesting.[26]

In Section 7.1.2 of its Opening Brief and in Section 7.6.5.4 of this Reply, ORA recommends that deferred PSEP work be prioritized and capped at the costs authorized in D.12-12-030. Consequently, ORA recommends that shareholders bear cost responsibility for all costs of that work over the costs established in D.12-12-030.

In Section 7.6.6 of this Reply Brief, ORA supports Indicated Shippers' proposal that shareholder be responsible for the costs of PSEP Phase 1 hydrotesting any pipeline segment that PG&E now proposes to replace.

ORA recommends shareholder cost responsibility for remedial work associated with corrosion repair, as discussed in Section 10 of its Opening Brief and this Reply.

As discussed in Section 13.6 of this Reply, where PG&E is conducting remedial work to correct pipe installed incorrectly for its class location, , ORA also recommends that shareholders bear cost responsibility.[27]

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[26] See, e.g., D.12-12-030, p. 61 ("Where such segments, and any segments installed after 1955 similarly lacking pressure test records, require replacement, rather than pressure testing, we grant PG&E's request to include in revenue requirement for recovery from ratepayers replacement costs but only to the extent the replacement costs exceed the estimated cost of pressure testing the segment.").

[27] As discussed in Section 13.6 of this Reply Brief, PG&E filed self-reports of probable violations with the CPUC regarding the incorrect installation of Line 300-B. In discovery, PG&E provided materials to ORA that demonstrated PG&E was moving these costs into "emergent work" to be paid at ratepayer expense.

3.1 ORA Proposals to Requiring Shareholders to Bear Cost of Forecast Work On the Basis of "Deferred Maintenance "or Unreasonable Decisionmaking Is Proper Under Commission Precedent

3.1.1 PG&E Itself Has Properly Made Shareholder Cost Responsibility For Numerous Repair Costs An Issue For This Proceeding, As Rate Proceedings Can Always Consider Shareholder Responsibility In Determining Reasonable Rates

PG&E offers the absurd argument that "shareholder cost responsibility is not properly an issue to this case," relying solely upon the fact that the Scoping Memos did not identify "shareholder cost responsibility" as a separately-defined issue. ORA offers that the determination of "just and reasonable" rates inherently considers the possibility of shareholder responsibility for unreasonable costs. Moreover, PG&E neglects that in its initial testimony, it had already specifically mentioned arguments noting that PG&E's Pipeline Pathways Program "efforts … are being performed at shareholder expense";[28] discussed revisions to GT&S Revenue Sharing Mechanism (GTSRSM) between shareholders and customers[29]; and, admitting that PG&E "has inadequately focused on certain aspects of corrosion control in the past,"[30] asserted that PG&E excluded certain corrosion costs from its forecast of work that it would perform "to address those deficiencies arising from past practices," thus admitting to shareholder responsibility for portions of costs. PG&E included issues regarding shareholder responsibility to justify its requested revenue requirement. The Scoping Memo, Issue 1 states:

> Whether PG&E's proposed 2015 revenue requirement for its GT&S services are just and reasonable, and should PG&E's proposed revenue requirement, or a different revenue requirement, be adopted;[31]

ORA submits that this provision clearly allows parties to make arguments regarding the "just and reasonable" proposed revenue requirement, which in itself would inherently

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[28] Ex. PG&E-1, pp. 2-25 to 2-26.

[29] Ex. PG&E-2, p. 18-2;

[30] Ex. PG&E-1, p. 7-6.

[31] *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* (Apr. 17, 2014), p. 2.

always potentially consider this issue of shareholder responsibility, especially when there are explicit cost sharing mechanisms between shareholders and ratepayers already in existence or potentially reasonable ratemaking proposals in response to an application, but specifically does so here because PG&E justified numerous aspects of its specific request on the basis of past and future shareholder responsibility for utility costs.

PG&E claims that "[o]nce a reasonable revenue requirement is established, the Commission does not then apportion payment between customers and shareholders,"[32] apparently overlooking that these arguments are used to establish that reasonable revenue requirement in the first place, and forgetting about specific cost sharing mechanisms that rate cases establish. Such disallowances to the reasonable revenue requirement do not violate the *Hope*[33] or *Bluefield*[34] standards.

3.1.2 TURN's Definition Of Imprudence Is Reasonable

Anticipating TURN's arguments, PG&E provides assurances that it "is not asking customers to pay for work already funded in prior rate cases, to remedy PG&E's prior alleged imprudence, or to remedy known cases of non-compliance with regulations."[35] It also explains that disallowances are appropriate if the Commission finds utility error: "If the Commission finds persuasive evidence that any of the costs in PG&E's forecast are directly attributable to clear and identifiable utility failures or errors, it can disallow recovery of such costs."

In fact, this is exactly what TURN proposes – disallowances for utility failures or errors. However, PG&E insists TURN is seeking disallowances where PG&E has simply failed to do work authorized in prior rate cases: "… TURN's sweeping assertion that

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[32] PG&E OB, p. 3-3.

[33] *Federal Power Commission v. Hope Natural Gas Co.* (1940) 320 U.S. 591, *cited by* PG&E OB, p. 3-3 fn. 15.

[34] *Bluefield Waterworks & Improvement Co. v. West Virginia Public Service Commission* (1923) 262 U.S. 679, *cited by* PG&E OB, p. 3-3 fn. 16.

[35] PG&E OB, p. 3-1.

costs can be disallowed as imprudent merely because, in hindsight, a prudent utility would have incurred them sooner, is contrary to established precedent." PG&E misrepresents TURN's position.

3.1.3

3.1.4

3.1.5

3.1.6 The Cases PG&E Reference Do Not Define Deferred Maintenance Solely As Costs Specifically Forecast And Not Spent, But Note That Deferred Maintenance Cannot Be Interpreted Simply In That Matter and Instead Review PG&E's Spending Decisions on a Reasonableness Standard Including Whether They Reasonably Identified Needed Maintenance

PG&E states in Section 3.1.6[36] that "[t]he issue of whether the costs of previously funded activities should be disallowed is what the Commission characterizes as 'deferred maintenance.'"[37] The primary decision which they cite for this alleged and overly narrow characterization is D.11-05-018, a decision approving a settlement agreement in the PG&E 2011 GRC. In this decision, which PG&E cites numerous times but the context of which PG&E never discusses, the Commission considered a specific settlement provision governing PG&E's ability to deviate from the specific cost levels used to comprise the overall revenue requirement in the settlement, in a case in which parties were challenging costs for maintenance that had been included in the previous rate case filing and then deferred.[38] There is no question that "deferred maintenance" can and has included costs for maintenance requested and approved in prior GRCs, which was not performed and then requested again in a subsequent GRC. However, the issue of whether deferred

[36] PG&E OB p. 10-7, Section 10.1.3, refers back to this section.

[37] PG&E OB, p. 3-11, *citing* D.11-05-018, *mimeo*, p. 27.

[38] D.11-05-018, p. 26 ("Certain parties were concerned that the process of reprioritization and deferral of certain costs has resulted in projects identified and adopted in a prior GRC being deferred by PG&E and included again in its request for this proceeding.")

maintenance **also** comprised other costs was not discussed in D.11-05-018 nor the settlement it approved with comments. As discussed further below, D.11-05-018 imposed conditions on the ability of PG&E to deviate from approved spending levels even in the settlement context in order to ensure that such final spending decisions were made reasonably, a condition which PG&E's OB fails to acknowledge.

PG&E's OB includes two block quotes from GRC decisions cited in D.11-05-018, PG&E's GRC in D. 83-12-068,[39] and a Southern California Edison GRC, D. 84-12-068.[40] Neither quote actually defines "deferred maintenance," but rather refer to examples that were not "deferred maintenance" according to other parts of the decisions that PG&E's OB does not reference.[41] A closer look at these decisions, and D.82-12-055, a prior Southern California Edison GRC decision referenced by D.83-12-068 for the definition of "deferred maintenance,"[42] reveals that it was PG&E itself that requested recovery for "deferred maintenance" costs including costs not included in prior rate case filings, but which PG&E included in a post-test year forecast and then removed from such forecast:

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[39] PG&E OB, p. 3-11 says the cite is to "D.88-12-068, 14 CPUC2d 15, 146," but D.11-05-018 correctly cited this case as "D.83-12-068." ORA recommends a LEXIS search for "8312068" to find the two parts of the decision on LEXIS.

[40] PG&E's OB correctly quoted D.11-05-018, but D.11-05-018 incorrectly cited "D.94-12-068, 16 CPUC2d 721, 782," rather than the correct decision associated with 16 CPUC2d 721, D.84-12-068.

[41] The previous paragraph in D.83-12-068 explains the scenario where PG&E delayed maintenance on particular equipment in advance of a study determining how much of that equipment would be retired, an approach staff had agreed with reasonable: "PG&E requested $372,000; the staff recommends $292,000, leaving $80,000 at issue. The difference relates to gas holder maintenance. PG&E's position is that the maintenance work is necessary. The work was delayed until the completion of the 1981 Transient Bay Area Holder Study and the decision which followed as to which gas holders to retain. According to PG&E, it would not have been prudent to perform maintenance on these facilities realizing that the Study was nearing completion and not knowing which gas holders would remain in service. The Study pointed out that six of the ten existing gas holders could be retired. The staff witness contended that this is deferred maintenance, yet he agreed that delaying maintenance on the gas holders until the completion of the 1981 Transient Bay Area Holder Study was prudent on the utility's part." D.83-12-068, 14 CPUC2d 15, 1983 Cal. PUC LEXIS 1154 (Part 2 of 2) at *6- *7. This particular holding has no applicability to the ORA's recommendations on corrosion and other items. Similarly, in D.84-12-068, regarding costs for a pole replacement program that Edison modified and "[s]taff has agreed that the improved deteriorated pole replacement program is an improvement over the original program," D.84-12-068, 16 CPUC2d 721, 1984 Cal. PUC LEXIS 1050 at * 111, the Commission stated that issue was not "deferred maintenance." Again, this holding does not apply to ORA's recommendations on corrosion and other items.

[42] D.83-12-068, 14 CPUC2d 15, 1983 Cal. PUC LEXIS 1156 at *118.

> PG&E submits that it derived the approximately $10.5 million worth of "deferred" maintenance activities included in this rate case by looking at maintenance activities that were at one time included in its 1981 budget and for various reasons were not performed during 1981. According to PG&E some of these activities might have been included as activities used to determine the 1980 test year rate case allowances. Many were new programs, developed during 1981, and were not even planned at the time rates were adopted for 1981. Thus, "deferred" maintenance cannot be interpreted simply as activities that were previously funded in rate cases that PG&E subsequently decided not to do. Many of these activities should be treated as new programs, or programs unfunded in previous rate cases.[43]

The Commission issued a "blanket denial of PG&E's request for deferred maintenance expense," noting "it was PG&E that labelled [sic] the items in question 'deferred maintenance'."[44] The Commission further stated:

> The reasonable way to evaluate a utility's maintenance activities is to ask whether the utility acted reasonably in maintaining its system. Did management identify needed maintenance? Did it set the proper priorities for performing maintenance? Did management set the proper priorities between maintenance activities and other utility activities?[45]

ORA's recommendations regarding "deferred maintenance" as regards corrosion spending are in line with this reasoning, regardless of particular nomenclature as to whether or not the argument classifies PG&E's actions as constituting "deferred maintenance."

PG&E's citation, again in the block quote on p. 3-11 to D.83-12-068[46] without any context, to a purported limit on recovery "work not deferred to improve the utility's financial position," misses the point, firstly because, as discussed above in footnote 41,

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[43] D.83-12-068, 14 CPUC2d 15, 1983 Cal. PUC LEXIS 1156 at *121.

[44] D.83-12-068, 14 CPUC2d 15, 1983 Cal. PUC LEXIS 1156 at *129.

[45] D.83-12-068, 14 CPUC2d 15, 1983 Cal. PUC LEXIS 1156 at *130.

[46] PG&E references D.11-05-018, *mimeo*, p. 27 on both p.3-2 fn. 9 and p. 3-11, fns. 44-46.

such work was not considered to be "deferred maintenance" at all for which funding would otherwise have been denied. The context at the time of the Edison GRC in D.82-12-055 was that the utilities were challenging the general requirement that they spend more than the authorized revenue requirement for otherwise necessary maintenance activities, and the Commission rejected this argument in upholding traditional forecast ratemaking:

> For us to authorize Edison's recovery of deferred maintenance expense would establish an undesirable precedent, whereby the utility is effectively guaranteed that it can earn (or exceed) its authorized rate of return, regardless of its operating efficiency or inefficiency, simply by curtailing current maintenance activities, in the assurance that they could be refinanced later through recovery of deferred maintenance expenses in a succeeding rate case. This would create a perverse incentive for the utility to defer needed maintenance in the future. Consequently, we will disallow recovery of the $34.6 million requested for deferred maintenance activities in 1983 and 1984.[47]

Now that the Commission has firmly established for more than three decades that the utility has the responsibility to spend more than authorized amounts if necessary to maintain safe and reliable service, a policy PG&E recognizes and states it has followed in this case through its high levels of spending in general maintenance, the issue is no longer whether the reason why a utility deferred maintenance was explicitly to lower costs, particularly when spending over the authorized amounts. The fact that any such deferred maintenance that should have been performed would indeed lower costs and improve the utility's financial situation has been established. The question turns on whether the decisions and decisionmaking process for determining maintenance should not be performed in a current ratemaking period but requested in the next constitutes reasonable management decisionmaking.

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[47] D.82-12-055, p. 37, 10 CPUC2d 155, 1982 LEXIS 1209 at * 63; *cited in* D.83-12-068, 14 CPUC2d 15, 1983 Cal. PUC LEXIS 1156 at * 123 - * 134. *See also* D.82-12-055, 1982 LEXIS 1209 at * 60 - * 63.

The Commission decision approving the settlement of the PG&E 2011 GRC, D.11-05-018, cited extensively by PG&E and discussed above, discussed the following settlement provision:

> The fact that Settling Parties set forth specific amounts for certain categories of costs is not intended to limit PG&E's management discretion to spend funds as it sees fit in a manner consistent with its obligation to provide reliable service and consistent with its obligation to maintain the safe operation of its utility systems. Nor does it limit the discretion of other parties to argue in future proceedings that it is unjust or unreasonable to make ratepayers pay a second time for activities explicitly authorized by the Commission in this proceeding **or that PG&E has not provided safe and reliable service**.[48]

The Commission described the responsibilities of the utility as follows:

> While we reaffirm that it is the utility management's prerogative and responsibility to provide safe and reliable service by reprioritizing and deferring activities as necessary, the Commission must be assured that the process is reasonable. We have concerns in that respect. For instance, despite any financial implications of exceeding authorized cost levels, the utility does have the responsibility to spend what is necessary to ensure safe and reliable service. To the extent a utility uses authorized cost levels as a reason for deferring activities, the Commission must be assured that such deferrals are otherwise reasonable especially with respect to safe and reliable service. Also, justified or not, reprioritization and deferrals undermine the basis for the Commission's determination of the reasonableness of the utility's GRC request and the extent of the authorized revenue requirement. Much of what is authorized is based on the utility's depiction of its needs and associated costs. Those needs and costs are tested by the GRC process. Reprioritized needs and associated costs may not be so tested and may not result in the most efficient use of funds. In light of these concerns, we will impose certain requirements on PG&E, as a step in ensuring that any reprioritization processes are reasonable and result in the best use of ratepayer funds.[49]

[48] D.11-05-018, pp. 28-29 and fn. 22, *citing* Settlement Agreement, Article 4.11 (emphasis added).

[49] D.11-05-018, p. 29.

The Commission required PG&E to file annual reports of authorized spending by Major Work Category, explaining differences from the authorized amounts from the Settlement Agreement and subsequent authorized budgets.[50] The Commission also stated:

> Also, in its next GRC, as part of its showing, PG&E should fully describe any reprioritizations and deferrals of costs explicitly identified in the Settlement Agreement or costs that can reasonably be imputed from the Settlement Agreement. PG&E should fully explain its reprioritization process, justify deferrals of specific activities and projects, and justify the implemented higher reprioritized activities and projects that were not identified in this GRC. For activities and projects that were deferred and are now being re-requested, PG&E should fully explain why they are needed now when they were able to be deferred before. The Commission will be critical in its evaluation of previously requested activities or projects that were deferred and re-requested keeping in mind that the utility has the obligation to maintain its operations and its plant in the condition to provide efficient, safe and reliable service, even if that condition requires more expenditures than the Commission has authorized.[51]

As discussed in Section 15 of ORA's Opening Brief, ORA supports approval of a stipulation entered into with PG&E on reporting requirements. If that stipulation is rejected, ORA recommends consideration of reporting requirements in this proceeding that are at least as detailed and frequent as the ones adopted in the 2011 for expenses such as corrosion, even where PG&E admits they are excluding some level of costs already from this proceeding for admitted non-compliance. PG&E's failure to fully, or even partially, discuss the contexts of the above decisions in conjunction with "deferred maintenance" renders its analysis flawed and misleading. Ultimately, the Commission utilizes the standard of reasonableness to review PG&E's decisionmaking, including deviations from approved spending levels in GRCs regardless of whether such work was specifically forecasted in a prior GRC under traditional ratemaking principles.

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[50] D.11-05-018, pp. 29-30.

[51] D.11-05-018, pp. 30-31.

4 Impact of Proposals on Customers

5 Ratemaking Issues

5.1 Amortization of Revenue Shortfall and Disallowance Due to Delayed Decision

5.2 Alternative Revenue and Ratemaking Proposals

5.3 Ratemaking Cycle

6 2011-2014 Capital Expenditures

7 Transmission Pipe

7.1 Overview and Summary

7.1.1 The Commission Should Establish Annual Requirements For Certain Critical Transmission Pipe Work Authorized In PSEP And This Rate Case

There are a number of factors under consideration in this proceeding which could result in PG&E not appropriately prioritizing and completing hydrotest, pipe replacement, or other work authorized in this rate case, or in prior Commission decisions. These factors include, among other things:

1. The existence of deferred PSEP hydrotest and pipe replacement work described in Section 7.6.5.4 below that was prioritized in PSEP for Phase 1, but which was not performed, and which PG&E says it will not perform in this rate case;

2. PG&E's implication that it will reduce the amount of work it proposes in this rate case if it does not receive all the funding it requests, regardless of the reasonableness of that funding request; [52]

3. Incentives PG&E may have to avoid performing work subject to disallowances in favor of work subject to full cost recovery from ratepayers; and

4. PG&E's requests in its GT&S Application to modify the scope of both the Hydrotest and VIPER Programs.[53]

All of these factors support the Commission's establishment of structural safeguards for PG&E's transmission pipe work, including: (1) prioritization of specific work; (2) identification of annual work requirements or "targets"; and (3) establishment of auditing monitoring and reporting functions to ensure that specified work is performed in a timely and appropriate manner regardless of the cost recovery authorized. For the reasons described in Section 7.6.5.4 below, ORA recommends that deferred PSEP work be prioritized to be performed before PG&E's proposed GT&S Program work.

7.1.2 The Commission Should Require Quarterly Reports Similar To The PSEP Quarterly Compliance Reports To Ensure Accountability and Transparency Regarding Transmission Pipe Expenditures

As demonstrated throughout this proceeding, PG&E's showing has not been substantiated by quality data, and when asked, PG&E was unable or unwilling to provide data supporting its forecasts, whether through data responses, or on cross examination.[54] To develop its proposed forecasts, ORA relied upon the extensive data available in PG&E's PSEP Quarterly Compliance Reports – reports which this Commission ordered

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[52] Ex. PG&E-1, p. 2-5 ("If the Commission provides fewer revenues than proposed, however, the trajectory of risk-reduction will be slower, resulting in a higher level of risk over a longer period of time.").

[53] See, for example, PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), pp. 4A-35 and 4A-59.

[54] See, e.g., ORA OB, p. 48, Footnotes 172 and 173; and this Reply Brief, § 7.4.2.1.1 regarding the willingness of PG&E's witness to testify regarding basic facts he should have been familiar with.

and specifically identified what they should contain.[55] Without this readily available data, the Commission would not have a true picture of what is happening regarding costs in PG&E's PSEP hydrotesting and replacement programs, other than the limited and distorted picture PG&E presented in this case.[56]

The transparency provided by the PSEP Quarterly Compliance Reports has been invaluable to ORA's work in a number of proceedings, including this one, and should continue until PG&E's reconstruction of its pipeline system is concluded. Among other things, requiring PG&E to prepare and distribute such reports will help ensure that PG&E performs work appropriate to the adopted budget and facilitate the development of more accurate forecasts in the next rate case.[57]

For these reasons, the Commission should continue the collection and organization of the valuable information provided by the PSEP Quarterly Compliance Reports by ordering PG&E to continue to produce a form of report similar to the PSEP Quarterly Compliance Reports for reporting costs for all of its hydrotesting, pipe replacement, in-line inspection, corrosion control, and new capacity and new business capital projects. However, the specific direction provided in Attachment D.12-12-030 for the PSEP Quarterly Compliance Reports would benefit from updating and clarification to ensure that information missing from the PSEP Quarterly Compliance Reports is included in the new report to provide the basis for more accurate forecasts in future rates cases.

ORA recommends that this reporting requirement be considered as part of a workshop process to address all reporting requirements, consistent with its stipulation with PG&E.[58] However, any order in these proceedings should be clear that the

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[55] See D.12-12-030, Ordering Paragraph 10 and Attachment D.

[56] See, e.g., Ex. ORA-34 (Direct Testimony, Correction Version, Roberts) throughout and specifically § 3.7; ORA OB, §§ 7.4.2 and 7.6.2; Ex. ORA- 47 (Supplemental Testimony, Roberts), pp. 3-4.

[57] The record shows that pipe replacement costs depend on the length, diameter, and location of the portfolio of projects. PG&E has proposed a portfolio of projects that addresses these cost drivers, and it should not be allowed to limit its expenditures by, for example, changing the portfolio to longer, smaller diameter, projects in less congested areas. See Note 184 in Section 7.6.5.2 below.

[58] Ex. Joint Stipulation-03, pp. 17-18. If the Commission does not adopt the workshop process proposed by PG&E and ORA, then ORA recommends quarterly reporting requirements for these programs

Commission seeks more, rather than less disclosure, and that the PSEP Quarterly Compliance Reports are the baseline. The question is how much additional information is needed to ensure transparency and facilitate the development of more accurate forecasts in the future. To this end, at a minimum, the new reports should identify:

1. *All* actual cost information incurred for these programs;

2. Costs as either fixed or variable costs and project-specific or program costs;

3. The portion of actual costs was paid by ratepayers and the portion paid by shareholders, and where shareholders have absorbed costs, the reasons for this; and

4. If any work projected to be completed has been cancelled or deferred and why.

7.2 In-Line Inspections

7.3 Direct Assessment

In its opening brief, PG&E admits that ORA was correct about PG&E double charging ratepayers for the 920 miles of transmission pipeline that PG&E wants to move from distribution to transmission integrity management.[59] Even though PG&E claims the double payment is "*de minimus*," and that the work is different,[60] this does not alter the fact that PG&E is charging ratepayers twice for the same 920 miles of pipeline.

PG&E states that "none of the approximately 920 miles that will be defined as transmission beginning in 2015 has been assessed using ILI, hydrostatic testing, direct assessment, or any other assessment method. Instead, these miles were included within

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consistent with the PSEP Quarterly Compliance Reports, as discussed herein, with some opportunity for parties to comment on how those reporting requirements should be modified to facilitate the development of more accurate future forecasts.

[59] PG&E OB, pp. 7-18, 7-19, and 7-20 to 7-21.

[60] PG&E OB, p. 7-19.

PG&E's Distribution Integrity Management Program, which does not focus on particular segments of pipe, but rather the system as a whole."[61]

First, as discussed in section 7.4.3 on pressure testing requirements since 1955, there has been a clear requirement to pressure test pipes, a requirement which only became stronger over the following 15 years.[62] With the adoption of GO 112, there was a requirement to pressure test all pipelines and mains operating at 20% or more of SMYS.[63] Starting in 1970, PG&E was required to test all pipelines placed into service.[64] Additionally, PG&E appears to be implying that they have not used any assessment methods, apparently contrary to the requirements of the Distribution Integrity Management Program or general operation requirements under federal code.[65]

PG&E describes the pipe as meeting one of three requirements: 1) change of function based at the distribution center; 2) operating at a hoop stress of 20% of more above SMYS; or 3) transporting gas to or within a natural gas storage field.[66] The only factual information PG&E provided is that these pipelines will be operating above 60 psig,[67] and that this program is designed to address High Consequence Areas.[68] PG&E is also unaware of exactly how many miles of pipeline are in HCAs, and will not have completed the studies until late 2015.[69]

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[61] PG&E OB, p. 7-20.

[62] Ex. ORA-173 (ASA Pressure Testing Standards Adopted Between 1935 and 1968), pp. 23-24.

[63] Ex. PG&E-109, p. 38.

[64] 49 Code of Federal Regulations §§192.505, 192.507, or 192.509. The requirements depend on the pipeline pressure and % SMYS at which the pipe is operating.

[65] PG&E OB, p. 7-20.

[66] Ex. PG&E-1, p. 4-3.

[67] Ex. PG&E-39, pp. 4A-19 to 4A-20.

[68] PG&E OB, p. 7-20.

[69] Ex. ORA-65, pp. 31-32. "The total population of new transmission mileage will not be known until that analysis is completed in late 2014. Those miles are then analyzed for new HCAs, which begin in 2015, with the final analysis completed in late 2015."

7.3.1 PG&E Uses Double Rounding To Exaggerate Its Direct Assessment Needs

PG&E rounds its assessments for the number of digs for ECDA upwards twice in order to maximize the amount of money in its forecast.[70] Even if the total number of digs per project provided by PG&E is used, correct mathematical averaging leads to a total number of 5.78 digs per project, not PG&E's inflated number of 7 digs per project.[71] PG&E's inflation of the number of digs per project is exacerbated by their lack of knowledge regarding how many miles of its system will be classified as HCAs under TIMP.[72] PG&E's use of stale, unrepresentative data from 2004 and 2005 that skews the entire 10 year digs per project average significantly higher while PG&E relies only on 2013 cost data. ORA's use of 2013 digs per project data ensures that costs and digs are based on the same figures, the most recent actual numbers.

The Commission should reject PG&E's arguments regarding the number of digs per project and accept ORA's more reasonable forecast based on the 2013 digs per project ratio instead.

7.4 Hydrostatic Testing

7.4.1.1 ORA Thoroughly Analyzed PG&E's Hydrotest Program Forecast And Demonstrated That It Was Unreasonable

PG&E's Opening Brief attacks ORA's proposed Hydrotest Program forecast on the grounds that it "ignored" multiple issues and costs. PG&E argues that "if one adds back in the missing components in ORA's proposal, the numbers demonstrate that

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[70] *See*, Ex. PG&E-39, p. 4A-22. For each year, PG&E divided the number of digs by the number of projects, and then rounded up. Again, to get the total, the already rounded up numbers were then rounded up again.

[71] 1173 digs / 203 projects = 5.78 digs per project.

[72] Ex. ORA-65, pp. 31-32.

ORA is also concerned that PG&E is apparently unaware of the class location characteristics of its gas pipeline system, given that the class location requirements are universal and not solely applied to transmission pipe. *See*, 49 C.F.R § 192.5.

PG&E's unit cost of $0.97 million per mile is fully justified."[73] PG&E is wrong on all counts.

The record shows that ORA did not "ignore" any part of PG&E's Hydrotest Program forecast – and particularly not the ones listed by PG&E in its Opening Brief. As reflected in its Opening and Supplemental Testimony, and in its Opening Brief, ORA extensively and meticulously studied and analyzed nearly every element of PG&E's Hydrotest forecast that it was possible to analyze given the dearth of data provided by PG&E. ORA then provided thoughtful and reasoned written testimony identifying the deficiencies in PG&E's forecast and supporting its own recommendations. ORA's analysis was based on PG&E data, established facts, and extensive knowledge of the PSEP program.[74] While PG&E may not *agree* with ORA's analysis, it is hard pressed to identify any issue that ORA ignored. Finally, adding back in everything that ORA took out of PG&E's unit cost forecast does not justify $0.97 million per mile, as PG&E insists. As described below, the highest forecast that 2013 recorded costs support is $0.85 million per mile – more than 12% less than PG&E's proposal – and still far above a "reasonable" unit cost given the downward cost pressures PG&E will experience during the rate case period.[75]

7.4.1.2 There Are Three Primary Differences Between The PG&E And ORA Forecasts

There are three primary factors that result in the difference between PG&E's 2015 Hydrotest Program forecast of $179.2 million and ORA's forecast of $91.7 million:

1. PG&E's data included a mix of mostly forecasted and actual costs. ORA's relied only on actual costs;

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[73] PG&E OB, p. 7-26. PG&E uses the term "ignore" three times, each time providing an example of an issue that was thoroughly addressed in ORA testimony, and shown to be without merit. This is not "ignoring." This is analysis based on facts and data.

[74] PG&E itself acknowledges "ORA's witness Roberts has a very good command of PG&E's PSEP forecast and the project level detail contained in the PSEP proceeding. Indeed, ORA included almost all documents from the PSEP proceeding into the record in this case to demonstrate support for its positions." PG&E OB, p. 7-40.

[75] PG&E OB, p. 7-28.

2. PG&E's data includes costs not included in the PSEP Quarterly Compliance Reports filed pursuant to D.12-12-030. ORA relied only on the PSEP costs reported in the PSEP Quarterly Compliance Reports; and

3. PG&E actively ignored (i.e. did not address in any evidentiary manner) extensive evidence of downward cost pressures when preparing its forecast – including the *fact shown in its own data* that its hydrotests will get significantly longer over the rate case period. ORA's forecast examined the full range of data available for the entire PSEP period, the type of work proposed for GT&S as compared to the PSEP work, various cost drivers, and opportunities for efficiencies. ORA incorporated this evidence into its forecast.

Each of these three differences is addressed in turn below.

7.4.1.2.1 Since PG&E Will Not Experience Rising Cost Pressures, Its Reliance On Forecast Rather Than Actual Costs Is Unreasonable

Regarding the first difference between the PG&E and ORA forecasts, PG&E's Opening Brief admits that the difference between using PG&E's forecast cost data as compared to using PG&E's actual cost data reduces PG&E's 2013 unit cost forecast from $0.97 to $0.85 million per mile.[76] This is a 12% difference. PG&E minimizes this differential by claiming that it "was able to conduct testing at a better unit cost than anticipated in 2013."[77] PG&E then points to its higher 2014 forecasted costs of $1.21 million per mile to attempt to demonstrate the reasonableness of its $0.97 million per mile unit cost forecast.[78]

In this manner, PG&E justifies using forecast rather than actual costs in its unit cost forecast by arguing that its anomalous 2014 hydrotest year shows that it will experience upward cost pressures during the rate case period. PG&E thus implies that the use of forecasted costs, with no recognition of falling cost trends, is reasonable.

[76] PG&E OB, p. 7-28.

[77] PG&E OB, p. 7-28.

[78] PG&E OB, p. 7-28.

This argument in support of using forecast costs, rather than actual costs, because of increasing cost pressures, is not supported by the record evidence. Among other things, PG&E data shows that its hydrotests will be getting substantially longer, *not shorter*, during the rate case period.[79] Thus, its entire argument for increasing cost pressures – the 2014 "shorts" – is not supported by the evidence. And PG&E provides no other evidence of upward cost pressures. And PG&E's own witness agreed that longer hydrotests should result in lower unit costs.[80] Similarly, all of the other evidence, meticulously described in ORA's Opening Brief, shows *downward* rather than *upward* cost pressures on hydrotesting during the rate case period.[81] These issues are discussed extensively in ORA's Opening Brief,[82] and are not revisted here.

7.4.1.2.2 ORA Properly Relied Upon Data In The PSEP Quarterly Compliance Reports

Regarding the second difference between the PG&E and ORA forecasts, PG&E's Opening Brief makes much of the difference between its own data set and the one used by ORA. It claims that ORA's forecast is "based on an incomplete data set."[83] Thus, PG&E readily admits that its PSEP Quarterly Compliance Report data – which is the data set ORA used – was "incomplete," and that it incurred millions in PSEP costs that it did not include in its PSEP Quarterly Compliance Reports.[84] However, it now includes these costs in its Hydrotest Program forecast.[85]

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[79] ORA OB, § 7.4.3.3.

[80] 17 RT 1751:19-24 (Barnes/PG&E) ("So one of your points here is that shorter hydrotest projects generally have higher unit costs and longer hydrotest projects have lower unit costs; is that correct? A Yes, it is correct…").

[81] See, e.g., ORA OB, § 7.4.3.

[82] ORA OB, § 7.4.3 regarding evidence that hydrotest costs will be going down during the rate case period, rather than up.

[83] PG&E OB, p. 7-25 (emphases and capitalizations removed).

[84] See also 17 RT 1746:7-9 (Barnes/PG&E) ("The actual cost information in PSEP quarterly compliance reports is accurate but incomplete.").

[85] PG&E OB, p. 7-26.

As ORA's Opening Brief explains, the exclusion of these costs is a violation of D.12-12-030, which clearly contemplated that PG&E should publicly report *all* actual PSEP costs in its Quarterly Compliance Reports.[86] ORA does not revisit that discussion here, other than to observe that PG&E should not be permitted to profit from violating a Commission order and failing to timely disclose its total actual PSEP costs. For this reason alone, it is appropriate to exclude these claimed costs from any final forecast approved in this proceeding.[87] However, as discussed in both ORA's Supplemental Testimony,[88] and in Section 7.4.2 below, there are many other reasons why ORA determined these "other" PSEP costs – whether reasonably incurred or not – should not be included in a GT&S forecast. Among them, some of the costs are properly born by shareholders because they were incurred due to lost records, some of the costs were PSEP start-up costs unlikely to be incurred in the rate case period, and some costs were impossible to verify.

7.4.1.2.3 PG&E's Forecast Unreasonably Ignores Downward Cost Pressures

Regarding the third difference between the PG&E and ORA forecasts, PG&E claims ORA "assumed unrealistic efficiency projections to support its recommended [forecast] reduction."[89] PG&E explains that it its $0.97 million per mile forecast" (1) "takes into consideration the types of projects it expects to complete in this rate case period"; and (2) "reflects PG&E's three years of experience in implementing the Hydrostatic Test Program under PSEP."[90] There is no factual basis to either of these PG&E claims, and PG&E testimony contradicts at least one of them.

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[86] ORA OB, § 7.4.4.

[87] Among other things, PG&E's failure to report and quantify these costs until well into the development of the record in this proceeding has made it nearly impossible for the parties to even determine whether the costs were reasonably incurred.

[88] Ex. ORA-47 (Supplemental Testimony, Roberts).

[89] PG&E, OB, p. 7-27.

[90] PG&E OB, p. 7-27.

First, PG&E's witness was clear that PG&E did not consider "the types of projects it expects to complete in this rate case period."[91] When asked specifically whether PG&E compared the type of projects performed in 2013 and those planned for 2015, PG&E's witness was emphatic that this did not happen. He explained that PG&E focused only on the number of miles proposed to be tested: "the number of miles is similar to what we're trying to put forth," and that PG&E only looked at the fact that "2013 is really about the *idea* that 2013 is the lowest cost we've seen over a period of four years."[92] PG&E emphasized this point repeatedly: "We're not trying to say that 2015 and 2013 *are the same*. We're trying to say that the lowest cost per mile that we can identify is $970,000 per mile. *So it's not really about them being the same. It's really about the unit cost being one in which we think that we can achieve certain efficiencies.*"[93]

PG&E's response to a very direct ORA data request was similarly clear that PG&E did *not* consider whether the scope and type of hydrotest projects completed in 2013 were representative of the tests it would perform in 2015. ORA asked: "Does PG&E contend that the scope and type of PSEP hydrotest work performed in 2013 is similar to the scope and type of hydrotest work in the proposed 2015 portfolio?"[94] PG&E stated that it based its forecast "on a high level look of miles in the program and number of projects, not on scope of projects given the high variability and lack of engineering completed on hydrotest projects."[95] To be clear - PG&E looked at the number of miles and projects, and its 2013 forecast costs, and that's all. PG&E's assertion that its forecast "takes into consideration the types of projects [PG&E] expects to complete in this rate

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[91] PG&E OB, p. 7-27.

[92] 17 RT 1747-1750 and specifically 1748: 14-26 (Barnes/PG&E) (emphases added).

[93] 17 RT 1749:1-11 (Barnes/PG&E) (emphases added).

[94] Ex. ORA 109 (PG&E Response to ORA DR 123 Q13(a)).

[95] Ex. ORA 109 (PG&E Response to ORA DR 123 Q13(a)).

case period"[96] is a significant overstatement, as both the record evidence and PG&E's testimony demonstrate.

Second, PG&E's analysis *did not* consider its "three years of experience in implementing the Hydrostatic Test Program under PSEP."[97] Specifically, PG&E's analysis incorporates *no data* regarding its PSEP work in 2011 and 2012. PG&E completely ignored this data, which showed a trend of significantly falling costs. Instead, PG&E relied only upon *forecasts* of actual costs for 2013 PSEP work, informed by the fact that this was "the lowest cost we've seen over a period of four years."[98] PG&E's failure to adequately consider and analyze the data from 2011 and 2012 was one of ORA's many significant critiques of PG&E's analysis.[99] It is hardly credible that PG&E now claims that it considered its 2011 and 2012 costs, and that its 2013 work is representative of its proposed 2015 work, thereby demonstrating the reasonableness of its forecast.

Ultimately, PG&E's entire argument for its very high unit cost forecast, and its refusal to consider evidence of downward cost pressures, rests on the sole premise that PG&E will experience upward cost pressures, as demonstrated by the "shorts" work performed in 2014.[100] ORA not only discredits that example by showing that PG&E's projects during the rate case period will grow increasingly longer,[101] but ORA also shows all the other reasons why PG&E will experience significant *downward* cost pressures

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[96] PG&E OB, p. 7-27.

[97] PG&E OB, p. 7-27.

[98] 17 RT 1748:22-26 (Barnes/PG&E).

[99] ORA OB, §§ 7.4.1 and 7.4.2.

[100] PG&E OB, p. 7-27. Note that PG&E's OB acknowledges that "PG&E was able to conduct testing at a better unit cost than anticipated in 2013." PG&E OB, p. 7-28. However, it continues to intentionally avoid any recognition of factors that may have contributed to lower than forecasted costs. PG&E is seeking to avoid creation of a record on these factors.

[101] ORA OB, § 7.4.3.3.

during the rate case period. These issues are addressed in detail in ORA's Opening Brief and will not be repeated here.[102]

7.4.2 PG&E's Unreported PSEP Hydrotest Costs Are Not Properly Included In Its GT&S Unit Cost Forecast

PG&E and ORA agree that a significant difference between PG&E's 2013 unit cost forecast of $0.97 million per mile and ORA's 2013 unit cost forecast of $0.72 million per mile is the fact that ORA used 2013 actual cost data as reported by PG&E in its PSEP Quarterly Compliance Reports. In contrast, PG&E used a database of forecasted and actual costs for 2013, which included approximately $24 million in "additional" costs PG&E claims to have incurred in the PSEP hydrotesting program.[103]

ORA has found that using PG&E's recorded PSEP actual costs, rather than its 2013 forecast of costs, closes the gap between the ORA and PG&E forecasts somewhat, as PG&E's recorded costs result in a unit cost of $0.84 million per mile. The remaining difference is presumably comprised of the difference between ORA's use of PSEP Quarterly Compliance Report costs as compared to PG&E's recorded costs, which include $24 million in PSEP costs for 2013 that were excluded from the PSEP Quarterly Compliance Reports.[104]

PG&E's Rebuttal to ORA's Supplemental Testimony showed that the $24 million is primarily comprised of two types of costs: (1) approximately $9.7 million in costs incurred for cancelled or deferred hydrotest projects; and (2) approximately $12.2 million in "general" PSEP program costs.[105] As discussed below, after analyzing PG&E's

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[102] ORA OB, § 7.4.3.

[103] Ex. PG&E-48 (Rebuttal to ORA Supplemental Testimony), p. 4AS-5. While PG&E identified in a data response that it had over $100 million in PSEP costs not included in the PSEP Quarterly Compliance Reports, it explained in Rebuttal to ORA's Supplemental Testimony that only $24 million of this amount was included in its 2013 Hydrotest forecast.

[104] Ex. PG&E-48 (Rebuttal to ORA Supplemental Testimony), p. 4AS-5.

[105] Ex. PG&E-48 (Rebuttal to ORA Supplemental Testimony), p. 4AS-5. PG&E also claimed "more than $2 million" in costs associated with PSEP work performed after project completion. ORA found this

accounts for these costs and the descriptions of the work performed, ORA determined that these costs should not be included in *any* GT&S forecast, whether ORA's or PG&E's.

7.4.2.1 PG&E Will Not Incur Significant Project Cancellation Costs During The Rate Case Period – And Even If It Does, Such Costs Should Not Be Recovered From Ratepayers

Regarding the approximately $9.7 million PG&E claims it incurred in 2013 for "cancelled" hydrotest projects,[106] the evidence shows: (1) to the extent PG&E does incur cancellation costs going forward, they are unlikely to be incurred at nearly the same level in GT&S because, among other things, completion of PG&E's Maximum Allowable Operating Pressure (MAOP) validation project and improved access to data should reduce the number of cancelled projects;[107] and (2) PG&E's "cancelled" projects were cancelled as the result of found records, which made the hydrotests unnecessary. Ratepayers should not pay for work required because of lost records. For both of these reasons, ORA properly excluded these cancellation costs from its 2013 forecast.

7.4.2.1.1 PG&E Should Have Significantly Fewer Cancelled Projects Going Forward, But Refuses To Acknowledge This Fact

All of the $39.167 million that PG&E associates with "cancelled" projects for PSEP in 2011-2013 has resulted from PG&E finding missing records.[108] In a data response PG&E explained: "To be clear, the definition of cancelled projects to PG&E in this context is that a job could be cancelled, the test records were verified … The impact

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claim was not supported by the data provided by PG&E. See ORA-47 (Supplemental Testimony, Roberts) pp. 19-20.

[106] PG&E's witness confirmed that PG&E had only quantified costs for "cancelled" projects and not costs for "deferred" projects in its testimony. 18 RT 1869-1870 (Barnes/PG&E).

[107] Ex. ORA-47 (Supplemental Testimony, Roberts), p. 5.

[108] The $9.7 million in the section above is for 2013 only, the $39.167 is for all three years.

is $39.167 million."[109] PG&E's witness confirmed this statement on cross examination.[110] He also confirmed that of the 783 miles PG&E proposed to hydrotest for PSEP, 162 miles were cancelled because of found records, and that these cancelled projects comprise the approximately $40 million that PG&E identified in its data responses to ORA.[111] He was also unable to identify any other reason a project would be cancelled, other than because of found records.[112]

It is common knowledge that correcting its recordkeeping practices, including locating missing records, organizing the records it has, and making them electronically accessible has been a key feature of PG&E's reforms for the past five years.[113] Further, PG&E has hydrotested a significant portion of its system that was missing records.[114] Consequently, it seems axiomatic that given better access to its records, and after completing hydrotests for many of the lines missing records, that PG&E would expect to cancel fewer projects, or to cancel them sooner, leading to significantly reduced cancellation costs in the GT&S period.

However, PG&E's witness was completely unforthcoming when cross examined on whether its improved recordkeeping practices and databases would make cancellations less likely. Notwithstanding that he is the Director of Transmission Integrity Management for PG&E, which is a record intensive program, he was unable or unwilling to describe how PG&E's recordkeeping systems have changed that would enable it to find more accurate records faster. While one would hope that PG&E's records have improved dramatically given the time and attention devoted to that exercise, and that PG&E's witness would be able to describe that evolution, he would only state that

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[109] Ex. ORA-120 (PG&E Response to ORA DR-123 Q11(a)).

[110] 18 RT 1898-1899 (Barnes/PG&E).

[111] 18 RT 1897-1898 (Barnes/PG&E). See also Ex. PG&E-48 (PG&E Rebuttal to ORA Supplemental Testimony), p. 4AS-6.

[112] 18 RT 1902:26 – 1903:17 (Barnes/PG&E).

[113] See, e.g., D.12-12-030 and D.15-04-021.

[114] See, e.g., Ex. ORA-121 (Excerpt of PG&E's PSEP Update Testimony), p. 2-29, Table 2-10 showing 658 miles pipe to be strength tested in PSEP Phase 1. See also D.12-12-030.

PG&E's record accessibility was "better" now than it was in 2012; when asked to give examples of how it was better he responded "It's more accessible."[115] When asked specifically if he expected cancellation costs to be higher or lower in PSEP as compared to GT&S, he stated: "You know, I don't know if I can speculate one way or the other on that."[116] These are two examples of the many instances demonstrating that PG&E's witness sponsoring both the Hydrotest and VIPER forecasts was either uninformed about basic facts, or unwilling to testify fully when asked direct questions. Either case requires that his testimony be given little weight.[117]

7.4.2.1.2 PG&E Ratepayers Should Not Be Responsible For Project Costs Resulting From Lost Records

Almost more significant than *whether* PG&E will incur cancellation costs going forward, is *why* PG&E incurred these costs. As confirmed by PG&E testimony and data responses, discussed above, PG&E incurred these project cancellation costs due to lost records. Specifically, PG&E incurred unnecessary hydrotest-related costs because it was unable to locate test records; once PG&E found the test records, it cancelled the projects, and now seeks to impose all costs associated with those cancelled projects on ratepayers.

In most instances it is likely that any resulting hydrotest cost would have been born by shareholders pursuant to D.12-12-030, yet PG&E seeks to impose the costs associated with cancelling those same hydrotests on *ratepayers*. Given that PG&E was required to pressure test its pipes starting in 1956 and retain those test records,[118] PG&E shareholders should be responsible for all cancellation costs associated with pipes installed after 1955, just have they have been responsible for all hydrotest costs associated with post-1955 pipes under D.12-12-030. Thus, even if PG&E were to incur

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[115] 18 RT 1888:22 – 1889:1 (Barnes/PG&E).

[116] 18 RT 1892:14-20 (Barnes/PG&E).

[117] Consider also PG&E's witness's inability to answer questions regarding hydrotest cost drivers such as mercury clean and water management costs. See ORA OB, p.48, Footnotes 172 and 173.

[118] D.15-04-021 (RK), pp. 99, 155, COL 54 (p. 300).

these types of costs in GT&S – which is unlikely – these costs are not properly included in PG&E's forecast because they are costs that should be borne by PG&E shareholders, not ratepayers.[119]

For all of these reasons, the $9.7 million PG&E has included in its Hydrotest Program forecast for cancelled projects should not be included in *any* forecast for the proposed Hydrotest Program – whether PG&E's forecast or ORA's. ORA's forecast does not include these costs, therefore accounting for part of the differential between PG&E's 2013 unit cost forecast of $0.97 million per mile and ORA's 2013 unit cost forecast of $0.72 million per mile, which was used to arrive at its 2015 forecast of $0.56 million per mile.

7.4.2.2 PG&E Could And Should Have Allocated Many Of Its "General" PSEP Program Costs To Specific Projects But Chose Not To – Belying PG&E's Claim That These Were "Program" Costs Properly Excluded From The Quarterly Compliance Reports

In its Rebuttal Testimony to ORA's Supplemental Testimony, PG&E identified $12.2 million in costs it claims it incurred in 2013 as general hydrotest program costs not included in its PSEP Quarterly Compliance Reports.[120] PG&E claims that ORA should have included these costs in its 2013 forecast.[121] ORA's decision not to include these costs in its forecast is supported by the evidence adduced in this case, and described in ORA's Supplemental Testimony[122] and Opening Brief.[123]

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[119] The likelihood of PG&E cancelling a hydrotest for a pipe installed pre-1956, even if records are found, is so negligible as to be insignificant.

[120] Ex. PG&E-48 (Rebuttal to ORA Supplemental Testimony), p. 4AS-5, Table 4AS-1, line 1.

[121] PG&E OB, pp. 7-25 – 7-27. Notably, ORA could not have included these costs in its forecasts because PG&E did not disclose/quantify the 2013-specific costs until its Rebuttal to ORA's Supplemental Testimony, issued January 12, 2015 (See Ex. PG&E-48).

[122] Ex. ORA-47 (Supplemental Testimony, Roberts), pp. 11-18.

[123] ORA OB, § 7.4.4.4.

In sum, it is simply wrong for PG&E to suggest that D.12-12-030 did not require it to report “program” hydrotest costs in its Quarterly Compliance Reports. ORA’s Opening Brief fully addresses this issue.[124] Further, while PG&E characterizes these costs as “program” costs,[125] ORA review of those costs, and PG&E testimony, reveals that many of these costs were project-specific costs that PG&E simply did not allocate to specific projects, even though it could and should have.[126] For example, PG&E explained in Rebuttal Testimony: “While not listing all the costs or duties some of the largest costs come from construction contractors who perform pipe inspections and remaining strength analyses, inspection of welds, and provide PG&E with required site inspectors. … PG&E is moving as much of these costs to the individual projects in 2014 and in the 2015-2017 rate case as possible, but this is a transfer of costs, not an elimination and they should have been included in ORA’s analysis.”[127] Thus, PG&E admits that it could have assigned these costs to specific projects, and will attempt to do so going forward. PG&E’s witness affirmed this testimony on cross examination and further confirmed that other work PG&E claimed was “non-job specific, non-PMO” was characterized in this way because a job order had not yet been created.[128]

Finally, as explained in ORA’s Supplemental Testimony[129] and its Opening Brief,[130] a significant portion of the nearly $63 million PG&E initially identified as “general hydrotest program costs” incurred between 2011 and 2013 could not be verified in any way because the cost data was lumped together under a general heading “Strength

[124] ORA OB, § 7.4.4.

[125] PG&E OB, p. 7-26 (“ORA also ignored several program costs or argued that they were temporary in nature.”)

[126] Ex. ORA-47 (Supplemental Testimony), pp. 12-13.

[127] Ex. PG&E-39 (Rebuttal Testimony), p. 4A-47.

[128] 21 RT 2324 (Barnes/PG&E).

[129] Ex. ORA-47 (Supplemental Testimony), pp. 11-18.

[130] ORA OB, § 7.4.4.4.

Test – Program."[131] Many of the costs appeared to have been incurred during the 2011 PSEP start-up period, or otherwise appeared to be costs unique to PSEP and unlikely to occur during GT&S. As such, ORA determined that these cost should not be included in any GT&S forecast, and declined to adjust its forecast to accommodate them. PG&E provided no factual rebuttal to ORA's conclusions regarding these costs. Consequently, ORA's forecast reasonably excluded these costs, and should be adopted.

7.4.3 PG&E Should Continue To Be Responsible For Hydrotest Costs Associated With Lines Installed Post 1955

In D.12-12-030, the Commission denied PG&E cost recovery for pressure testing pipes installed after 1955:

> We find that where PG&E undertook or stated that it undertook to comply with industry standards but no longer possesses the records of such compliance, the costs of retesting required by the missing records is a result of an *error* in PG&E's operation of its natural gas transmission system. Where PG&E's *record retention errors* have led to re-testing pipeline installed between 1955 and 1961, the costs of such re-testing is not a just and reasonable cost of providing public utility service. Such costs, therefore, should be excluded from authorized revenue requirement to be recovered from ratepayers.[132]

PG&E seeks to relitigate this issue in this proceeding, claiming that "the evidence in this proceeding fully supports recovery of these costs."[133] PG&E provides no new evidence on this issue in this proceeding, and the evidence in this proceeding is virtually the same as that relied upon in D.12-12-030 to determine that PG&E's ratepayers paid

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[131] The $63 million figure is for 2011-2013. The $12.2 million figure at the beginning of this section refers to 2013 only.

[132] D.12-12-030, p. 58 (emphases added); see also Conclusions of Law 15 and 16.

[133] PG&E OB, p. 7-30.

once for pressure tests, and should not be responsible for paying a second time due to PG&E's "error."

Instead of identifying new evidence in the record to support its arguments, PG&E's Opening Brief mischaracterizes the evidence showing that ratepayers funded PG&E prior pressure tests and relied upon by D.12-12-030, and by the parties in this case. It claims the parties assert that "PG&E stated in a data request response in PSEP that it believes the costs of post construction strength tests *were included in its cost forecasts*."[134] The evidence of ratepayer funding, relied upon by D.12-12-030, and the parties in this case, is far more concrete than PG&E admits. PG&E was asked: "Were these tests funded by PG&E ratepayers or PG&E shareholders?" PG&E answered: "The testing was part of the pipe installation costs and, therefore, would have been funded by ratepayers."[135] PG&E did not limit its answer to including those costs in *forecasts*. It admits ratepayers funded the tests.

PG&E's Opening Brief then turns to a new legal argument that because industry standards have changed between 1956 and 1961 – requiring a specified duration for hydrotests – that ratepayers should be responsible for the new hydrotests. It points to its witness's "direct and rebuttal testimony that provides analysis of the strength testing requirements under the industry standard…" Notably, this testimony was struck from the record.[136]

Even considering PG&E's struck testimony, PG&E overstates its case. The modest change from no requirement to specify a duration in the 1955 ASA standards to a requirement to specify at least a one hour duration in GO 112 does not support PG&E's request to shift the costs of 1955 to 1961 hydrotests from shareholders to ratepayers for several reasons. Most significantly, PG&E ignores the fact that although the standards

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[134] PG&E OB, p. 7-31 (emphases added).

[135] Ex. ORA-113 (R.11-02-019, PG&E Response to DRA-DR-045, Q7(f)).

[136] See 31 RT 4294:13 – 4298:15 (striking PG&E's direct testimony on the duration issue in Ex. PG&E-1, p. 4A-43, lines 12-15); and 26 RT 3484:28 – 3486:5 (striking PG&E's rebuttal testimony on the during issue in Ex. PG&E-39, p. 4A-60 line 10 to p. 4A-61, line 3).

between 1956 and 1961 did not *require* test results to include a test duration, the majority of PG&E's tests for that period do include a duration, and most of them far exceed the one hour duration adopted in the 1961 rules.[137] The evidence in this case shows that of those test records that PG&E does have for this period, approximately 61% show a duration of one hour or more,[138] and 0.5% show a duration of less than 1 hour.[139] The other approximately 38% of entries were blank. Consequently, while PG&E may attempt to mischaracterize tests performed between 1955 and 1960 as "unacceptable" because no duration was required to be specified,[140] the evidence does not support PG&E's position. First, the majority of tests for which there are records complied with the new 1961 duration requirement. Second, for those test records where no duration was specified, it is possible the duration was for an hour or more. Among other things, a test duration was typically related to the amount of time it would take to "walk" the line and do leak inspections, which was often more than an hour. Third, there is no evidence in the record demonstrating that PG&E's lost records would show anything different from PG&E's existing records – that the test duration was often identified and often met or exceeded the requirements imposed in 1961.

PG&E's Opening Brief suggests that many other standards changed between 1955 and 1961, thus justifying its request to move pressure test costs for these pipes to ratepayers.[141] PG&E's arguments have no merit. ORA demonstrated through its exhibits and under cross-examination that the ASA standards from 1955 to 1961 did not change significantly.[142, 143] There is no question that from 1955 onward, the ASA standards

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[137] Ex. ORA-174 (ORA Data Request to PG&E 147, Question 2 and Attachment 1). See also 31 RT 4278:1-12.

[138] In D.11-06-017, OP 3, the Commission required a minimum of a 1 hour duration for pre-General Order 112 (e.g. pre-1961) pressure tests.

[139] Ex. ORA-174 (ORA Data Request to PG&E 147, Question 2 and Attachment 1). See also 31 RT 4278:1-12.

[140] PG&E OB, p. 7-33.

[141] Indeed, PG&E in OB, p. 7-32, seems to characterize the *more stringent* requirements under the ASA standards as somehow being problematic compared to GO 112.

[142] Ex. ORA-175 (Chart comparing ASA standards from 1935-1968, GO 112, and 49 CFR 192).

required pressure testing for all pipelines in Class locations 2, 3, and 4 operating above 100 psig.[144] While PG&E claims it had no obligation to test pipes in Class 1 locations during that period,[145] the ASA standards *did* provide guidance on how to test a pipe in a Class 1 location, and there is no evidence suggesting that PG&E did not do this, nor has PG&E provided any evidence that any of the pipes in Class 1 locations were operating between 100 psig and less than 30% of the Specified Minimum Yield Strength.[146]

Finally, with regard to PG&E's claim that it had no obligation to retain records for certain tests,[147] the ASA standards make no distinction among pressure test records that should be retained and others that need not be. The 1955 standard states:

> Records. The operating company shall maintain in its file for the useful life of each pipeline and main, records showing the type of fluid used for test and the test pressure.[148]

Decision 15-04-021 in the San Bruno Recordkeeping Investigation similarly relies upon the same ASA standard to determine that PG&E was obligated to retain pressure test records, and does not distinguish among the types of pressure tests records, or suggest that some need not be retained.[149]

In sum, PG&E has presented no new arguments or evidence that merit reversing the determination in D.12-12-030 that PG&E should be responsible for the costs of pressure testing lines installed between January 1, 1956 and June 30, 1961. The

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[143] 31 RT 4278:13 – 4286:19 (Skinner/ORA).

[144] Ex. ORA-175, page 2.

[145] PG&E OB, p. 7-33.

[146] ASA B31.8 (1955), §§ 841.412 and 841.42. Also see Ex. ORA-175.

[147] PG&E OB, p. 7-33.

[148] Ex. ORA-175, ASA B31.8 (1955), §841.417.

[149] D.15-04-021, FOF 47 ("ASME B.31.8 § 841.417 specified that records of these pressure tests were to be retained for the useful life of the pipeline.") and 116 ("ASME B.31.8 § 841.417 requires pressure test records to be retained for the life of the pipe.").

determinations made in D.12-12-030 should stand, and should be clarified to reflect that all hydrotest costs associated with missing records, including cancellation costs incurred before records are found, should be disallowed for purposes of ratepayer recovery.

7.5 Earthquake Fault Crossings

7.6 Vintage Pipe Replacement

7.6.1 PG&E Has Not Met Its Burden Of Proof

PG&E's Opening Brief discusses its burden of proof, and how expert opinions must be supported by factual data.[150] PG&E cites California case law in support: "An expert's opinion is no better than the reasons given for it. If his opinion is not based upon facts otherwise proved ... it cannot rise to the dignity of substantial evidence."[151] ORA agrees, and its Opening Brief meticulously documents how PG&E's showing does not meet these basic standards.

For its Vintage Pipeline Replacement Program (VIPER), PG&E's Opening Brief contains rhetoric and narratives of its testimony unsupported with evidence. For example, PG&E states that its witness:

> testified at length that PG&E's forecast is based on those PSEP projects with similar pipe diameter in locations similar to the locations included in PG&E's 2015-2017 program. He also discussed that PG&E used both 2013 forecast and 2013 actual costs (to the extent available) to use the most recent data available to support its forecast. There are no "problems with the data PG&E used." Mr. Barnes also testified to why ORA's analysis, which applied PSEP data indiscriminately to develop a unit cost forecast, was inappropriate for the new Vintage Pipe Replacement Program.[152]

PG&E mischaracterizes the record, which clearly shows that PG&E's witness offered many opinions regarding PG&E's VIPER forecast, but cited to virtually no facts, data, or

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[150] PG&E OB, pp. 1-2 to 1-4.

[151] PG&E OB, p. 1-4 quoting *Griffith v. County of Los Angeles* (1968) 267 Cal. App. 2d 837, 847.

[152] PG&E OB, p. 7-41 quoting Ex. ORA-34, p. 54, lines 16-18.

quantitative analysis supporting his view. Applying PG&E's own definition of its burden of proof and the validity of expert testimony, PG&E's showing fails.

The record also reflects that to the extent parties attempted to obtain data from PG&E, it was often unavailable. For example, when asked whether PG&E had any data regarding fixed and variable costs that could inform its hydrotest or pipe replacement forecasts, PG&E's witness admitted "there's a lot of data" but that "[g]etting to some of this information is pretty onerous …"[153] TURN correctly surmises that "parties thus cannot test the historical validity of PG&E's assertions regarding these cost drivers, simply due to PG&E's accounting system."[154] TURN's observation is supported by ORA's experience, described in its Opening Brief,[155] and tabular data compiled by Indicated Shippers (Indicated Shippers) showing that PG&E's reported costs changed over time.[156]

A fundamental question that PG&E has failed to address, and that must be answered before PG&E's VIPER forecast can be adopted, is how PG&E's PSEP forecast was flawed. PG&E criticizes ORA for making comparisons between the forecasts for these two programs arguing that the PSEP forecast "was developed in 2011 prior to gaining program experience through implementation of PSEP."[157] However, ORA has demonstrated that this argument has no merit: pipe replacement has been occurring for decades, and there have been no major changes in pipe replacement processes.[158] Also, PG&E's pipe replacement experience *prior* to PSEP was one reason the CPUC adopted PG&E's PSEP forecast over ORA's much lower forecast.[159] Nevertheless, PG&E now asserts that it now needs a VIPER budget more than double its PSEP forecast because the

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[153] 19 RT 1970 (Barnes/PG&E).

[154] TURN OB, p. 116.

[155] See, e.g., ORA OB, § 7.6.2.

[156] Indicated Shippers OB, p.137, Table 7.6-5.

[157] PG&E OB, p. 7-40.

[158] ORA OB, pp. 94-95.

[159] ORA OB, pp. 94-95.

PSEP forecast was flawed. However, PG&E fails to provide any evidence supporting this claim. The more likely possibility is that PG&E was unable to control costs in the wake of San Bruno.[160]

ORA showed that pipe replacement should be a core competency of both PG&E and the expert consultant it hired to develop its PSEP forecast.[161] While PG&E may rely only on rhetoric to support its desire to "make sure there's enough dollars in the [VIPER] program," the Commission must ensure the correct burden of proof has been met, and this requires comparison to the PSEP forecast.[162]

As ORA has shown, PG&E's forecast is based solely on its averaging of the costs of nine specifically selected PSEP projects.[163] In contrast, ORA provided comparisons to water pipeline replacement,[164] and TURN provided a comparison to PG&E's own request to construct a new pipeline, Line 407.[165] Both of these analyses support ORA's forecasted unit costs rather than PG&E's. PG&E's lack of due diligence must be considered in the evaluation of the reasonableness of its budget request.

7.6.2 The Evidence Provided By ORA, TURN And Indicated Shippers Shows That Congestion And The Length And Diameter Of VIPER Projects Do Not Justify VIPER Costs Significantly Higher Than PSEP

PG&E claims that "ORA [] disputes that location and length of pipe are cost drivers in PG&E's Vintage Pipe Replacement Program."[166] This mischaracterization of ORA's analysis, testimony, and briefs can be corrected by adding a phrase at the end:

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[160] It is likely that PG&E was focused on responding to the condemning findings of the NTSB and CPUC that followed the San Bruno explosions, and was not able to simultaneously control costs on ramping up "unprecedented" PSEP pipeline and valve remediation projects, hiring a new gas operations management team, performing MAOP validation, and participating in the three CPUC investigations that followed.

[161] ORA OB, pp. 94-95 and 96.

[162] PG&E OB, p. 7-39 quoting Mr. Barnes at 19 RT 2121 – 2122 (Barnes/PG&E).

[163] ORA OB, § 7.6.3.

[164] ORA OB, pp. 116-123.

[165] TURN OB, pp. 128-129.

[166] PG&E OB, p. 7-41.

"*relative to PSEP*." Certainly project length and location have an impact on project cost. However, as described in ORA's Opening Brief,[167] and summarized below, ORA provided extensive evidence showing that the length and location of proposed VIPER projects are *not significant relative to PSEP projects*, and more importantly, that any differences relative to PSEP *do not result in significant differences in unit costs*.

7.6.2.1 Both PSEP And VIPER Focus Primarily On Congested Areas If PG&E's AOC/TOC Prioritization Method Is Approved, But Both Programs Also Include Pipes In Less Congested Areas

PG&E repeatedly explains that VIPER projects will be located in "populated" or congested areas.[168] For example, PG&E states that "since PG&E's program prioritizes projects based on population density, *it stands to reason* that past replacements in congested areas are representative of the costs PG&E expects to incur in this rate case period."[169] ORA agrees that it is reasonable, given PG&E's *voluntary* decision to focus VIPER in congested areas first, to use PSEP project costs as the basis of a forecast, since the Commission *required* PSEP to focus on highly populated areas.[170] However, as ORA's Opening Brief explains,[171] PG&E's justification for relying *only* on PSEP projects located in "congested" areas in its forecast fails for each of the following reasons:

1. PG&E's choice to prioritize projects based on AOC is not fundamental to the stated goals of the program. In other words, *VIPER projects could be located in less congested areas, and PG&E may well elect to pursue those projects in lieu of projects in more congested areas*;

2. PG&E fails to recognize that PSEP work focused on highly populated HCAs as a fundamental requirement of the program, thus the vast majority of PSEP projects are located in "congested" areas;

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[167] ORA OB, §§ 7.6.5.2 and 7.6.6.

[168] PG&E OB, p. 7-37.

[169] PG&E OB, p. 7-39 (emphases added).

[170] ORA OB, p. 88.

[171] ORA OB, pp. 87-88. See generally all discussion in § 7.6.6.

3. In PSEP, PG&E increased the scope of pipe replacement to include non-HCA areas where it improved the efficiency of the program. PG&E has provided no evidence that a similar shift to less populated areas, to improve the efficiency of the program, should not be expected for VIPER;

4. PG&E provides no analysis or quantitative support to show how the project locations anticipated for VIPER will lead to increased costs compared to PSEP;

5. PG&E's forecast for large pipes assumes all projects will be in the "super congested" San Francisco Peninsula – thus assuming even higher costs than "congested" areas;

6. Within the rate case period, the level of congestion decreases based on PG&E's AOC prioritization process, which should result in VIPER projects located in less congested areas, thus reducing annual program costs; and

7. PG&E's definition of "congested" relative to VIPER is poorly defined and has changed over the course of this proceeding.

Further, TURN's Opening Brief uses PG&E data to show that PG&E's assumptions about VIPER projects being in congested locations "may not apply to a number of large local transmission projects."[172] ORA confirmed that *nearly half* of all 81 VIPER projects are located in unincorporated areas rather than within cities.[173]

7.6.2.2 PG&E's Exclusive Use Of Projects On Line 109 To Support Its Large Pipe Unit Cost Is Unsupported And Inconsistent With Its Testimony

PG&E's testimony discusses how it selected PSEP projects to determine its unit costs based on locations that it progressively defined as "highly congested," then "congested," and finally "complex."[174] However, TURN's opening brief illustrates how

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[172] TURN OB, p. 120.

[173] PG&E listed the city associated with 40 of its 81 proposed projects as "Unincorporated County." See Ex. ORA-92 (ORA Workpaper "WP-ORA-4C-13.xls," tab "ORA-088 Q3-ORA.") which provides the city and county of each proposed project.

[174] ORA OB, pp. 93-94.

PG&E, by including only PSEP projects from Line 109 in its large diameter forecast – a line located in the "super congested" San Francisco Peninsula – ignored projects in less congested locations to fabricate its chosen unit cost irrespective of the locations for proposed VIPER projects.[175] As ORA also observed, less than half of the 27 currently proposed large diameter VIPER projects will be located on the "super congested" San Francisco Peninsula, so that PG&E's decision to include only projects from Line 109 in its large diameter forecast unreasonably results in premium unit costs being applied to *all* large diameter VIPER projects.[176]

7.6.2.3 Fixed Costs For Replacement Projects Are Small Relative To Variable Costs, So Differences In Average Project Lengths Between PSEP And VIPER Are Not Significant, Particularly In Terms Of Cost Impact

Similar to its congestion claims, PG&E has reiterated multiple times in this proceeding that VIPER costs will be higher because "shorter pipe segment replacements [in VIPER relative to PSEP] will necessarily drive unit costs up."[177] As meticulously described in § 7.6.5 of ORA's Opening Brief, PG&E's assertion that shorter project lengths will drive up unit costs relative to PSEP is simply wrong. Among other things, ORA shows that after 500 feet, project length has minimal impact on project unit costs for pipe replacements, such that the unit costs for a project longer than 500 feet will be similar to a project 1 or 2 miles long.[178] ORA further showed that only 8 of PG&E's 81 proposed VIPER projects are shorter than 500 feet long, and PG&E's workpapers indicate that 18 VIPER projects are one mile or longer, such that there is no support for PG&E's claim that VIPER is comprised primarily of short projects.[179]

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[175] TURN OB, pp. 117-120.

[176] ORA OB, p.77.

[177] PG&E OB, p.7-41.

[178] ORA OB, § 7.6.5.2 and specifically pp. 85-86.

[179] ORA OB, p. 86 and Ex. PG&E-5, pp. WP 4A-711 to WP 4A-712.

PG&E asserted in Rebuttal Testimony that cost increases are potentially directly proportional to decreases in length, but Indicated Shippers correctly showed that this can only be true if all costs are fixed, and this assumption contradicts the only available data on fixed as compared to variable costs for pipe replacements, and contradicts PG&E's own witness.[180]

ORA's opening brief provided three ways to consider PG&E's claim that the length difference between PSEP and VIPER projects led to significant cost differences, all of which showed the difference was minimal, including one that showed the impact was no more than 1.2%.[181] As with many PG&E claims in this case, basic analysis and evidence contradicts PG&E's assertions. TURN correctly concludes "Whether one uses average length or median length is not the critical issue. The real issue is *when is the impact of fixed costs relevant*."[182] ORA compared the number of very short projects (e.g. less than 500 feet long) *forecasted* in PSEP to those *forecasted* for VIPER. ORA found that the PSEP forecast had approximately five times more short projects than PG&E currently forecasts for VIPER. Thus, shorter VIPER projects cannot account for the difference between the PSEP and VIPER forecasts.[183] TURN compared the number of very short projects (e.g. less than 500 feet long) *completed* in PSEP to those *forecast* for VIPER and found that PSEP had slightly fewer short projects, but correctly concluded "the impact of short segments on unit costs should be fairly similar for both [PSEP and VIPER] programs."[184] Both analyses debunk PG&E's assertion that shorter project lengths drive VIPER costs significantly higher than those incurred in PSEP.

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[180] Indicated Shippers OB, pp. 139-140.

[181] ORA OB, pp. 81-86.

[182] TURN OB, p. 122 (emphases added). In fact, both statistics provide value. The average length allows comparison of the number of projects required to meet a mileage target, and hence frequency with which fixed costs are incurred. The median length provides a measure of the number of short projects relative to long projects. ORA's OB explains how both statistics support that length differences will not have significant cost impacts.

[183] ORA OB, p. 86.

[184] TURN OB, p. 123. Among other things, there is evidence that during PSEP PG&E shifted from shorter, more expensive projects, to longer projects over the program period. Ex. ORA-92 includes data

In hearings, PG&E's witness implied that ORA's derivation of the relationship between project length and unit cost was only academic: "I agree that this is a great hypothetical representation of that ideal but I don't necessarily see how it works with our actual costs and so I'm not really sure how I can make that correlation."[185] PG&E's position is unsupported, and inconsistent with the data and analysis provided by at least three parties in this proceeding, and the data it presented in the PSEP proceeding in support of its PSEP unit cost forecast. In addition to ORA and TURN, Indicated Shippers conducted its own analysis of actual cost data for large pipes and found "no statistically significant relationship between project length and average cost."[186] The ORA and Indicated Shippers analyses provide very different perspectives, but both provide hard evidence that VIPER costs will not be significantly higher based on the length of projects *relative to PSEP*.

7.6.2.4 PG&E Incorrectly Accuses ORA Of "Data Issues" Due To ORA's Use Of Credit Length Instead Of Installed Length And Tie-In Date Instead Of Project Completion Date

PG&E is critical of the PSEP Quarterly Compliance Report data ORA used in its VIPER analysis and to support its forecast.[187] PG&E was more specific in its Rebuttal Testimony, where it stated "it appears that ORA did not use actual PSEP pipe replacement length to make the calculation; ORA used 'credit miles,' which is a term used in PSEP to identify the length that is required to be replaced in order to meet objectives. Actual project length is generally longer than this length."[188] PG&E

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which shows that nearly 50% of the replacement projects in PG&E's original PSEP *forecast* were shorter than 0.1 miles (Ex. ORA-92, Workpaper "WP-ORA-4C-7, PSEP REPL Forecast.xls," tab "Histogram of L," cell B171.) TURN's Opening Brief at page 123 shows that only 14.5% of the PSEP replacement projects *actually completed*, seven of the 48, were shorter than 0.1 miles, as supported by Ex. ORA-126 (Attachment 1 to PG&E's response to DR-ORA-141 Q1).

[185] 18 RT 1956 (Barnes/PG&E).

[186] Indicated Shippers OB, p. 140.

[187] PG&E OB, p. 7-42.

[188] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-69.

expressed similar concerns regarding ORA's use of the tie-in date. [189] However, on cross examination, PG&E's witness acknowledged that "installed dates" were not provided for all projects through discovery, that "credit miles" is not a term that is used in the PSEP Quarterly Compliance Reports, and this created confusion when parties attempted to analyze PSEP data.[190] PG&E's criticism of the data used by ORA is misplaced, unless PG&E has been reporting incorrect data for completed projects in Section 11 of each to the PSEP Quarterly Compliance Reports it has submitted to the Commission.

7.6.2.5 PG&E's Unit Cost Forecasts Based On Only Three Diameters Are Arbitrary And Impede Accurate Forecasting

In its Opening Brief, Indicated Shippers correctly observes that PG&E's use of three unit costs based only on pipe diameter limits the accuracy of PG&E's forecast, and limits efforts to determine if the estimate is reasonable.[191] Among other things, comparisons between PSEP costs and the VIPER forecast are complicated because PG&E used only three diameters in VIPER, as compared to four diameters used in PSEP.[192] ORA agrees, and adds its own observations regarding the diameter breakdowns

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[189] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-73:

"Q 224: What else was wrong with this data integration?

A 224: ORA used tie-in dates to determine that all costs were included for a project, which resulted in incomplete cost data.

Q 225: What cost data was incomplete in ORA's analysis?

A 225: ORA used cost data from the PG&E's discovery response, ORA 64Q13, for actual costs that were not fully booked for some projects because even though the project was tied-in, the costs were not closed for the project. ORA's analysis used that "tie-in" date as being "project complete" date, which was an incorrect usage of that data.

Q 226: What would be the impact on their unit cost analysis of leaving out full project costs?

A 226: ORA's unit cost analysis would have missed some costs in their analysis, causing unit costs to become inappropriately deflated."

[190] 19 RT 1972-1989.

[191] Indicated Shippers OB, p. 130.

[192] Indicated Shippers OB, p. 130.

PG&E used to apply its proposed VIPER unit costs to individual projects, and then determine a VIPER program cost:[193]

1. PG&E grouped 12" pipes in its lowest cost group in PSEP, but in the medium cost group in VIPER. 12" pipes represent a significant portion of PG&E's transmission pipeline, and PG&E has proposed 84 projects with this diameter in VIPER, out of a total of 891 proposed VIPER projects.[194] Thus, thus the cost impact is potentially significant, even though the difference between PG&E's small and medium diameter unit costs in the VIPER program is only $100 per foot or $520,000 per mile;[195]

2. PG&E's VIPER forecast does not include a unit cost for 18", 20", and 22" pipes. These pipe diameters are used in PG&E's system, and PG&E has 121 projects with these diameters in its list of proposed VIPER projects;

3. While PG&E grouped 24" pipes in its third-highest cost group in PSEP, it claims to have included these pipes in the highest cost group in VIPER.[196] 24" pipes represent a significant portion of PG&E's transmission pipeline, and PG&E has proposed 82 projects with this diameter in VIPER. Thus, the cost impact is potentially significant, particularly since this VIPER unit cost forecast is more than double the forecast for medium size pipes;[197] and

4. PG&E does not provide a unit cost for 34" pipes. These pipe diameters represent the most mileage in PG&E's system, and PG&E has proposed 420 projects with this diameter for VIPER.

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[193] Except as noted in the text, references are as follows: (1) PSEP pipe sizes and unit costs are from Ex. ORA-85 (PG&E Direct Testimony in PSEP, Chapter 3), p.3E-15; (2) VIPER sizes and unit costs from Ex. PG&E-5 (Chapter 4A Workpapers , volume 2), p. WP 4A-722; (3) Data on the sizes of PG&E's transmission pipe are from Ex. PG&E-1 (Prepared Testimony, Chapter 4), p. 4-6, Figure 4-2; and (4) Diameter of VIPER projects are from Ex. IS-70 (Excel versions of PG&E Workpapers), file "CH 04A.xls," tab "WP 4A-711 - WP 4A-721," sorted by column E, outside diameter (inches).

[194] This includes all projects proposed in PG&E Chapter 4A workpapers, including "post rate case" projects.

[195] This includes both 12" and 12.75" pipes. PG&E's unit costs in GT&S are $1,000 per foot for small pipes, and $1,100 per foot for medium size pipes. See, e.g., Ex. ORA 34 (Direct Testimony, Corrected Version, Roberts), p. 36, Table 4C-7.

[196] PG&E's workpapers are not consistent with each other regarding whether PG&E applied the medium or large size forecast to estimate the cost of replacing its 24" pipes. One part of the workpapers use a cost of $1,100 for 24" pipes (starting at WP 4A-711). However, the workpaper defining the unit costs indicates the higher unit cost of $2,500 for 24" pipes (WP 4A-722.)

[197] PG&E's unit costs in GT&S are $1,100 per foot for medium size pipes and $2,500 per foot for large pipes.

In sum, there is no logical reason for PG&E's new grouping of pipes by diameter, which deviates from its PSEP grouping without any explanation, and does not cover all the types of projects it proposes for VIPER. While a more granular breakdown might have been an appropriate deviation from PSEP, moving from the four PSEP groupings to the less granular three grouping proposed in VIPER is perplexing. ORA can only conclude that PG&E intentionally categorized its pipelines in this way to prevent comparison with past pipe replacement costs,[198] and to further facilitate the reverse-engineering ORA identified in Section 7.6.10 of its Opening Brief and in various sections of this Reply Brief.

Further, it appears from a revised PG&E data response submitted on November 24, 2014 that PG&E may have "erred" in its application of its VIPER unit costs to its proposed VIPER budget of $193.8 million by incorrectly applying the significantly lower medium size forecast to 24" pipes, rather than including them in the larger pipe category.[199] To the extent such an "error" has occurred, it has no impact on ORA's recommended budget of $110 million for the VIPER Program, because for the reasons listed above, PG&E's allocation of 24" pipes to the large category was arbitrary. ORA's forecast relied upon PG&E's Direct Testimony and included 24" pipes in the medium category for arriving at a program costs. As there is no principled reason or evidence to support their allocation in one size and cost category instead of another – and even PG&E seemed to go back and forth on which category 24" pipes should be included in – PG&E's "error" is irrelevant to the forecasts already proposed in this proceeding.

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[198] Indicated Shippers OB, p. 130.

[199] On October 2, 2014, PG&E indicated through a data response to ORA (Ex. ORA-49 (DR-ORA-128 Q9 rev 1) that it had mistakenly applied the $5.8 million per mile unit cost for medium pipe to 24" pipes, rather than the intended $13.2 million per mile unit cost, resulting in an underestimation of VIPER costs of $71 million over 3 years, 2015-2017. This statement was not a response to the DR issued, but rather something PG&E uncovered when preparing its response. PG&E has not mentioned this issue elsewhere in the record, nor has it adjusted its 2015 program forecast, or even quantified for ORA how the "error" impacts its 2015 forecast. ORA elected to include PG&E's revised data response in the record of this proceeding because the value of the other evidence provided in the data response was of greater weight than the impact of the "error" PG&E identified in that response.

7.6.3 In Contrast To PG&E's Forecast, ORA's Forecast Is Accurate, And Has Not Changed During The Course Of This Proceeding

Section 7.6.3.3 of PG&E's Opening Brief concludes: "ORA's calculation, corrected for errors and applicable data, supports PG&E's unit cost forecast."[200] PG&E mischaracterizes ORA's analysis. PG&E did not find or report errors in ORA's analysis; rather, PG&E performed a new analysis tailored to support its forecast, and mischaracterizes ORA's analysis in the process.[201] ORA's Opening Brief describes the primary differences between PG&E's Rebuttal Testimony unit costs and ORA's:[202]

1. ORA includes all projects during the subject time period, while PG&E removes all projects it classifies as rural and not on Line 109; and

2. ORA includes projects with a tie-in date before 2014, while PG&E uses a new and flawed "operational date" to include projects completed in 2014.

These differences are differences in methodology, not data errors, and PG&E has provided no evidence that ORA's forecast includes any methodological errors.

More generally, PG&E asserts that ORA used "incomplete or inappropriately integrated data" which "resulted in unreliable conclusions."[203] The issue of ORA's use of "credit miles" and "tie-in" data are addressed above. The remainder of PG&E's arguments focus on ORA's use of data from the PSEP Quarterly Compliance Reports. As described throughout ORA's Opening Brief,[204] it was reasonable for ORA to use PSEP Quarterly Compliance Report data for its analyses, and if PG&E provided incomplete PSEP data in these reports, as its testimony in this case affirms, the Commission should consider imposing sanctions for Rule 1.1 violations.

ORA's forecast data and methodology are documented both in narrative form and in workpapers, defining the term "transparency." ORA's forecast has not changed over

[200] PG&E OB, p.7-42.

[201] TURN OB, pp. 126-127.

[202] See Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-74, Table 4A-13.

[203] PG&E OB, p. 7-42.

[204] See, e.g., ORA OB, §7.4.4.

the course of this proceeding, and PG&E has identified no specific data integration or merging errors, as opposed to differences of opinion, in ORA's analyses.[205] In contrast, as ORA demonstrates,[206] PG&E's slim showing in its Application provides no supporting data for its proposed unit costs. Consequently, PG&E was left to incrementally supplement and modify its "analysis" through Rebuttal Testimony and Errata in response to parties' legitimate criticisms.[207] While PG&E's proposed unit costs did not change, the record shows that on several occasions PG&E revised its VIPER analysis to either eliminate or include projects supporting its three proposed unit costs.[208] This is all evidence that PG&E picked its desired annual budget first, and then reverse-engineered its forecast to identify projects and unit costs to support this budget.[209]

Indicated Shipper's Opening Brief effectively shows how critical cost data provided by PG&E through discovery changed over time, and necessitated the use of public data in the PSEP Quarterly Compliance Reports.[210] If not for the Commission mandating those reports in D.12-12-030, it would have been nearly impossible for parties like ORA to provide reasonable alternatives to PG&E's rudimentary forecast.

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[205] As previously mentioned, the primary difference between ORA and PG&E's forecast is due to the PSEP projects included and excluded from each analysis. PG&E may not agree with ORA that all PSEP projects should be included in the GT&S forecast, including large diameter pipe on lines other than 109. However, ORA's criteria are logical, clearly defined, and well supported. It is wrong for PG&E to claim that the differences are due to any type of error on ORA's part. In contrast, PG&E's use of an "Operational Date" rather than a "Tie-in Date" is a true error because the later date was used by PG&E in reporting data on completed projects to the Commission, and a pipe cannot logically be operational before it is tied-in. See 18 RT 1948: "Q: Well, based on just the words, is it possible to have a pipe operative before it's tied in? A: Oh, no."

[206] See, e.g., ORA OB, §§ 7.6.2 and 7.6.4.

[207] ORA OB, pp. 67-70.

[208] See, e.g. ORA OB, §§ 7.6.4 and 7.6.5.

[209] ORA OB, pp. 99-101.

[210] Indicated Shippers OB, p. 137, Table 7.6-5.

7.6.4 PG&E's Claim That "Further Efficiencies Are Expected To Be Negligible Over This Rate Case Period" Demonstrate An Unwillingness To Exercise Prudent Project Management[211]

PG&E claims in its Opening Brief that "further efficiencies are expected to be negligible over this rate case period."[212] In this way, PG&E attempts to justify escalating its already high VIPER forecast for each year of the rate case period. However, the evidence shows that there are many opportunities for cost savings or "further efficiencies" that reduce costs at least enough to offset inflation. Section 7.6.12.3 of ORA's Opening Brief discusses these opportunities, places them within the context of an attrition year stipulation that provides for escalation in 2016 and 2017, and explains how this results in ORA's 2015 VIPER forecast being generous.[213] In addition, Section 7.6.6 of ORA's Opening Brief discusses how decreasing population within the Potential Impact Radius (PIR) of target pipelines should also lead to lower unit costs.

TURN also agrees that costs should continue to decline because "PG&E has had much more time to plan for this program than PSEP and can learn from its PSEP experience."[214] ORA and TURN provided well-reasoned justifications for forecasting VIPER costs that do not escalate beyond PSEP costs, nor increase during the rate case period. In contrast, PG&E applies blanket escalation rates that are inconsistent with the vintage of PSEP cost data, and with no justification that they apply to VIPER, other than PG&E's claim of "upward cost pressures."[215] Section 7.6.9 of ORA's Opening Brief explains why PG&E's claim is unsupported and wrong.

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[211] PG&E OB, p. 7-45.

[212] PG&E OB, p. 7-45.

[213] ORA OB, § 7.6.12.3. Page 107 shows how the overall impact is to provide an additional $8 million over three years to PG&E beyond what is supported by the record.

[214] TURN OB, p. 124.

[215] See ORA OB, Section 7.6.8, for details on how PG&E incorrectly used an excessive escalation rate.

In sum, efficiencies and their resulting cost benefits will only be realized for ratepayers if PG&E is held accountable for controlling costs. This is yet another reason supporting the reasonableness of ORA's forecast in lieu of PG&E's.

7.6.5 PG&E's "Flip-Flop" Regarding The Threats To Be Mitigated Through VIPER Demonstrates That PG&E Has Not Fully Or Properly Designed This Program, And Supports ORA's Recommendation That PG&E Delay VIPER While Gathering Geo Hazard Data

PG&E has flip-flopped from its PSEP position regarding threats to its pipeline system. The threat PG&E argued not to address in PSEP – vintage pipes with fabrication issues in unstable areas – is now the only threat it proposes to mitigate through VIPER.[216] This fact alone should cause the Commission to question PG&E's ability to accurately evaluate risks to its pipeline system. PG&E further confuses the issue by changing the scope it proposes to address with VIPER, and attempts to shift attention away from its change in position by claiming that ORA's proposal to delay VIPER implementation increases risk. In fact, the record in this proceeding shows the ORA's proposed schedule for VIPER is safe and reasonable, but should be supplemented with additional requirements to ensure that PG&E has accurately defined the threats to be addressed by the program, has a valid methodology to evaluate and rank those threats, and that it has prioritized projects consistent with the threat of pipe failure as well as its consequences.

7.6.5.1 Threats Posed By Vintage Pipe Features In Geologically Unstable Locations Are Not New

PG&E claims that VIPER "addresses *a newly-identified* and serious threat,"[217] and that this threat "is one of the top risks facing the transmission pipe asset."[218] This is nonsense. ORA's Direct Testimony discusses how PG&E, ORA, and TURN consultants

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[216] See Note 219, below.

[217] PG&E OB, p. 7-36 (emphases added).

[218] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p.4A-55.

all knew about and identified this threat in 2011, yet PG&E explicitly rejected this information and convinced the Commission to adopt PSEP decision trees that pressure tested rather than replaced these pipelines.[219] PG&E states that a November 2011 accident in Tennessee resulted in a "change in focus," to support its assertion that VIPER addresses a new threat,[220] but this accident occurred well *before* PG&E *actively* took a position *not* to address this threat in PSEP.[221] PG&E should have admitted that it incorrectly evaluated the risk of this threat during PSEP, and that it has changed its position. However, PG&E instead tries to frame this issue as something "newly-identified," akin to how it identified corrosion as a new threat justifying a ten-fold increase in its forecast request for corrosion control.[222]

7.6.5.2 PG&E Has Not Consistently Defined The Threat It Seeks To Mitigate Through VIPER, Nor Can It Accurately Identify The Greatest Threats Posed By Land Movement

Indicated Shippers correctly explains that the scope of PG&E's proposed VIPER project is ambiguous.[223] PG&E initially defined the land movement to be addressed by VIPER as essentially all types of movement, except where a pipeline crossed a known

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[219] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 32-33 discusses the positions of consultants on this issue. See Ex. ORA-84 (PG&E PSEP Rebuttal Testimony, Chapter 3, Hogenson), p. 3-7. PG&E's witness explains: "DRA, TURN, and UA recommend removing [the criteria of having a previous hydrotest] because they claim that a hydrostatic test is not well suited for evaluating the features of the Fabrication and Construction Decision Tree." Those features included wrinkle bends, miter> 3 degrees, and non-standard fittings. PG&E's witness concludes that while this recommendation "could be considered to provide a lower risk solution, the addition of those replacement miles would be offset by not replacing select untested pipeline segments with manufacturing threats." Thus, in PSEP, PG&E specifically rejected inclusion of VIPER like projects since they would displace higher risk work. In GT&S, PG&E has not shown if and why the situation has been reversed. D.12-12-030 approved PG&E's decision tree without modification or comment on this issue. See D.12-12-030, COL 9, p. 121.

[220] PG&E OB, p. 7-38.

[221] PG&E's PSEP Rebuttal Testimony was served on February 28, 2012. See Ex. ORA-84 (PG&E PSEP Rebuttal Testimony, Cover Page).

[222] PG&E OB, p. 10-2.

[223] Indicated Shippers OB, pp. 120-122.

earthquake fault.[224] This was confirmed in response to an ORA data response.[225] As the proceeding progressed, however, PG&E changed the definition such that VIPER was only going to address "slow, creeping land movement," as opposed to "sudden events" like landslides.[226] PG&E implies that this shift was precipitated and supported through a Joint Industry Project (JIP),[227] but the "JIP Report" PG&E initially claimed would be available "early in 2014"[228] was not produced through discovery or hearings.[229] Thus, PG&E has provided no support for its limiting the scope of VIPER.

PG&E's lack of support for its changing target of what land movement VIPER will address has not prevented PG&E from attempting to rebut the testimony of parties revealing that PG&E was not able to effectively identify or prioritize regions of land movement. PG&E states that it used USGS *landslide* data to determine VIPER projects,[230] but then criticizes Indicated Shippers for referencing the Battelle report, which also used *landslide* data, because it does not address "slow creeping ground movement."[231]

PG&E also claims that VIPER is "based on the best available knowledge of locations of vintage construction threats and whether they align with California USGS land slide susceptibility," but provides no evidence to show how this particular USGS

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[224] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p.4A-52, Note 19: "Types of land movement addressed include slow land movement, liquefaction, areas of seismic activity, creep, and other types of land movement. This program does not, however, address the threats posed when natural gas pipelines cross earthquake faults." Emphasis added.

[225] Ex. ORA-80 (PG&E Response to DR-ORA-91 Q23) ("The Vintage Pipe Replacement Program is targeting any land movement locations that are specifically crossing the pipeline at locations that have vintage construction/fabrication threats." (Emphasis added).).

[226] PG&E OB, p. 7-47.

[227] PG&E OB, p. 7-38.

[228] Ex. PG&E-1(Direct Testimony with Errata, Chapter 4A, Barnes), p. 4A-53.

[229] Ex. ORA-134 (PG&E Response to DR-ORA-91 Q19). PG&E revised the due date from "early in 2014" to "by the end of 2014." In hearings ORA asked "has that report been completed and made available?" PG&E's witness stated: "I do not have an update for you on that at this time." 19 RT 2074 (Barnes/PG&E).

[230] PG&E OB, p. 7-36.

[231] PG&E OB, p. 7-47.

data set allows them to define and prioritize VIPER projects.[232] PG&E's inability to prioritize is equally applicable whether PG&E's definition of VIPER's target land movement is "slow [and] creeping," or the broader definition PG&E originally provided. Either way, PG&E has not shown that it can accurately identify land movement, which supports the need for the results of its Geo Hazards program to inform its VIPER priorities.

7.6.5.3 PG&E Attempts To Deflect Criticism By Stating That VIPER "Address[es] Risk Holistically" And ORA's "Approach" Would Result In Greater Risk

PG&E attempts to shift attention away from its own inability to evaluate risk and properly prioritize VIPER projects by stating "[W]hat ORA has trouble accepting is that PG&E's programs set forth in this rate case, and particularly the Vintage Pipe Replacement Program, are intended to address risk holistically. That is different from PSEP."[233] The "trouble" is not ORA's; it is that PG&E's changing definition of the type of land movement it hopes to target, and its limited ability to prioritize the risks posed by that land movement, demonstrate that PG&E has not adequately addressed risk in the design of this program.

More globally, as even PG&E has observed,[234] the problem is that PG&E's assessment of risk is designed to identify high consequence, low probability events.[235] This leads to results such as VIPER being the highest ranked threat to PG&E's system, over common occurrences, such as third party construction hits.[236] As discussed below, Indicated Shippers has shown that 99.8% of PG&E's customers are already protected

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[232] PG&E OB, p. 7-36.

[233] PG&E OB, p. 7-40.

[234] *See*, Ex. PG&E-30, p. 2A-3. "The risks documented in the Risk Register are predominantly the worst consequence scenarios, meaning high consequence but low probability risks."

[235] *See,* Ex. ORA-53, p. 13.

[236] Ex. ORA-53, p. 11. In the risk register PG&E used to develop its GT&S forecast, the score for VIPER projects is nearly twice as high as older seam types, approximately 15 times higher than corrosion, and nearly 30 times higher than mechanical damage, such as dig ins.

against the threat proposed to be eliminated by VIPER. Consequently, any risk reduced by the VIPER Program would be negligible compared to other work PG&E could pursue.

PG&E's inability to prioritize risk is demonstrated in a number of ways specific to the VIPER Program. PG&E has stated that "when the ["vintage features" considered in Figure 4A-11] interact with land movement, they behave similarly." [237] In making this assertion, PG&E assumes that all pipe features interact the same and that evaluating the *consequence* of failure is more important than determining the *probability* of failure. This is simply not the case if identifying and prioritizing risk is the objective.

As mentioned in Section 7.6.5.2 above, PG&E's definition of land movement has changed over the course of this proceeding, and PG&E fails to even define "slow, creeping land movement" in its own procedures, the type of threat it now claims VIPER is designed to address. [238] Further, PG&E contradicts itself in response to an ORA data request, stating that "PG&E did not specifically discern between liquefaction and landslides" in identifying VIPER projects. It then references its risk management procedure RMP-04, and states that "areas of known landslide locations are ranked above …[k]nown [l]iquefaction areas."[239] Thus, it appears PG&E does not even understand its own program and how it prioritizes work.

Indicated Shippers accurately concludes that PG&E's risk analysis, as used to define VIPER, fails to address the "likelihood of failure" and "did not fully gauge the consequences of failure."[240] As Indicated Shippers has shown, PG&E's prioritization by AOC/TOC results in increasing protection from this interactive threat from 99.8% today, to nearly 100% by 2025.[241] Thus, it is hardly credible that VIPER addresses "one of the top risks" to PG&E's pipeline system if the initial baseline is so high, and the incremental

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[237] Ex. ORA-134, PG&E Responses to DR-ORA-91 Q8 and Q9.

[238] Ex. Indicated Shippers-30, PG&E RMP 04, which was last updated in 2012 as revision 7, includes factors for landslides, liquefaction, seismic acceleration, erosion, and other factors, but includes no mention of "slow, creeping land movement."

[239] Ex. ORA-134, PG&E Response to DR-ORA-91 Q7.

[240] Indicated Shippers OB, p. 124.

[241] Indicated Shippers OB, p. 128.

improvement in coverage so low. It seems more reasonable that the risk is high because of the *probability* of failure, and this is based on the ground (i.e. how it moves, and the potential that it will move) and the pipe in the ground (i.e. the specific type of pipe feature being stressed by ground movement). PG&E fails to adequately address these *fundamental* elements of an effective VIPER program. Instead PG&E focuses on the secondary *impacts* of a failure, rather than the *risk* of failure. This is because PG&E has been unable to effectively quantify risk. As such, PG&E should be required to properly define and identify the VIPER Program before receiving funding.

ORA agrees with PG&E's witness that human impacts matter. Consequently, ORA strongly supports the concept that the magnitude of the consequences of pipeline failures should be a significant criteria in the selection and prioritization for all programs, including VIPER. However, identification of the highest risk pipe features when subjected to *specific* outside forces is at least as important as population density in the overall risk analysis.

PG&E is correct that ORA has not argued that this program is not required, but it is incorrect that ORA's approach would "halt PG&E's progress in applying risk principles to its investment decisions."[242] ORA has justifiably challenged the adequacy of PG&E's risk analysis and the rigor of its assessment.[243] In fact, ORA's proposal that VIPER be coordinated with deferred PSEP work and the currently proposed Geo-Hazard Program suggests a more integrated or "holistic" approach than PG&E has advocated for, incorporating reason, consistency, and effectiveness into all three programs.[244]

7.6.5.4 Deferred PSEP Work Should Be Prioritized And Subject To The Cost Limitations In D.12-12-030

In D.12-12-030, the Commission adopted PG&E's proposed PSEP Decision Tree, which established a methodology to prioritize PSEP work so that the pipe segments

[242] PG&E OB, p. 7-40.

[243] ORA OB, pp. 4-5.

[244] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 34-35.

posing the most threat to PG&E's system were mitigated first, either through hydrotesting or replacement. Decision 12-12-030 also established cost caps for "Phase 1" PSEP work to be performed prior to 2015.[245]

ORA's Direct Testimony identified a significant amount of Phase 1 PSEP work that PG&E has not performed, and recommended that PG&E delay the start of VIPER until it has completed this work and gathered data through its Geo Hazards program.[246] Specifically, Section 3.4.2 of ORA's Direct Testimony identifies 119 miles of deferred work ("Group 1" deferrals include a combination of hydrotesting and pipe replacements) where PG&E determined not to do the mitigation determined by the PSEP Decision Tree.[247] That same discussion identifies another 45 miles of work ("Group 2 deferrals include a combination of 20.2 miles of pipe replacement and 24.8 miles of hydrotesting) that should have been performed if PG&E had rerun its Decision Tree after MAOP validation.[248] In other words, the updated record information provided by MAOP validation required that additional lines should have been tested or replaced during PSEP Phase 1.

ORA also observed that had the work been performed, as required by PSEP, it would have been subject to the cost caps established in the PSEP Decision. ORA notes that the PSEP disallowances have created a strong financial incentive for PG&E to defer work to the GT&S case where it could seek higher unit costs and potentially see an end to these disallowances.[249] PG&E should not be rewarded for its delay in performing the deferred PSEP work, and its attempt to side step its PSEP obligations by proposing new

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[245] D.12-12-030 approved PSEP Phase 1. It was anticipated that the next round of hydrotesting and replacement would be PSEP "Phase 2." As described in ORA's testimony (Ex. ORA-34, pp. 56-65), PG&E has abandoned the concept of Phase 2 PSEP work and now proposes the Hydrotest and VIPER Programs to replace PSEP Phase 2.

[246] Ex ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 56-65.

[247] Ex ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 59-64, and specifically p. 60.

[248] Ex ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 59-64, and specifically p. 61.

[249] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 59, Lines 14-24.

programs to replace PSEP. The Commission should require the work to be done and the PSEP caps should be applied, with escalation, to that work now.[250]

PG&E does not claim that the deferred PSEP work does not exist. On cross examination its witness acknowledged the deferred work and affirmed that PG&E had no plans to perform the work.[251] In its Opening Brief, PG&E argues that ORA's proposal to prioritize the deferred PSEP work before VIPER should not be adopted because VIPER "addresses one of the highest risks faced by PG&E's gas transmission system" and "the PSEP deferred projects do not pose as high risks … and should not be implemented ahead of projects in the Vintage Pipe Replacement Program."[252] ORA disagrees.

As discussed in Section 7.6.5 above, PG&E has flip-flopped on the priority issue, arguing vehemently in the PSEP proceeding that its PSEP Decision Tree identified the proper priorities, and explicitly rejecting ORA concerns regarding the vintage pipes in unstable locations now proposed to be addressed by the VIPER Program.[253] Further, as discussed in Section 7.6.5.3, the fact is that VIPER cannot pose one of the "highest risks faced by PG&E's gas transmission system" since even now, before any VIPER work has been performed, 99.8% of the population located along PG&E's transmission system is immune to this threat.[254]

Other information provided in this proceeding, particularly from Indicated Shippers, confirms that ORA's original recommendation was reasonable. Given the limited state of the record in this proceeding regarding the value of VIPER in addressing imminent risks on PG&E's system, ORA recommends that PG&E be required to clarify the scope of threats to be addressed in VIPER to demonstrate that it accurately and comprehensively targets the highest risk pipelines within this scope.

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[250] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 59-64, and specifically p. 61

[251] 18 RT 1847-1848 (Barnes/PG&E).

[252] PG&E OB, p. 7-47.

[253] See also Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 31-35.

[254] Indicated Shippers OB, p. 128.

In the interim, PG&E should be directed to complete the pipe replacements and hydrotesting that would have been required under PSEP Phase 1.

7.6.6 ORA Supports Indicated Shipper's Recommendation That Shareholders Pay For Replacement Of Pipe That Was Previously Hydrostatically Tested

Indicated Shippers state: "If ratepayers previously paid for hydrostatic testing of a pipeline segment that PG&E now proposes to replace, any recoverable replacement costs should be reduced by the cost of the Phase 1 testing."[255] PG&E argues that "the interactive threat that is addressed in the Vintage Pipe Replacement Program is not one that can be mitigated through hydrostatic testing."[256] Section 7.6.5.1 above demonstrates that PG&E was fully aware that hydrotesting would not remove the threat to be addressed by VIPER, but proceeded with hydrotesting anyway. Indicated Shippers correctly notes that PG&E's witness described PG&E's previous programs as emergency response programs and design procedures for fault crossings, neither of which are relevant to the types of mitigation proposed for VIPER.[257] ORA supports Indicated Shipper's recommendation that PG&E shareholders bear the costs of the prior hydrotest, similar to the replacement disallowance provided in D.12-12-030, since PG&E elected to pressure test, rather than replace, pipe where PG&E knew replacement was the only solution to the problem.

7.6.7 Summary Of VIPER Cost Forecasts

Notwithstanding that VIPER represents a significant portion of this rate case, PG&E's Opening Brief provides little support for the program. In contrast, Indicated Shippers, TURN, and ORA all offer extensive analysis and supporting evidence

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[255] Ex. Indicated Shippers-6, p. 74, lines 2-5.

[256] PG&E OB, p. 46.

[257] Indicated Shippers OB, p. 126.

identifying deficiencies in PG&E's VIPER forecast. From ORA's perspective the key failings of PG&E's forecast are:

1. PG&E's VIPER forecast is not supported by evidence; and does not meet the required burden of proof;

2. PG&E cherry-picked projects to support its primary objective - to support a very large budget. This is particularly true for large diameter pipes;

3. PG&E's requested costs are not justified by claims of increased congestion and decreased length *relative to PSEP*; and

4. PG&E's claims of "upward cost pressures" are unsupported and wrong.

Each of these issues is addressed in the ORA, TURN, and Indicated Shippers' Opening Briefs, and within this Reply Brief. All three parties also provided alternatives to PG&E's forecast. ORA's forecast was the most detailed, and was largely supported by TURN and Indicated Shippers because:

1. ORA's forecast, based on PSEP recorded costs from public data, is reasonable, accurate, well supported, and has not changed during this rate case;
2. ORA's position that costs will decline is reasonable;
3. PG&E's PSEP unit cost forecasts for pipe replacements is a reasonable, and generous baseline against which to determine the reasonableness of PG&E's unit cost forecasts for VIPER; and
4. The cost to replace water pipelines in San Francisco and the East Bay is a good reference point for determining the reasonableness of PG&E's VIPER forecasts.[258]

[258] PG&E implies that the costs to replace gas pipes are more expensive than water pipes because of the volatile nature of gas, and the repercussions of having gas leak out of the completed pipe. This critique ignores the fact that water is the only utility resource that is ingested by humans, and that the repercussions of intrusions into a completed water pipe also have negative impacts. While no party has quantified the relative health and safety impact of gas excursions vs. intrusion of contaminants into water lines, it supports that water pipelines are also highly regulated which adds costs to their construction and replacement.

In sum, a full and detailed record has been developed by parties that support ORA's VIPER forecast as the most reasonable option for the Commission to adopt.

7.6.8 Recommendations

ORA recommends that the Commission order the following tasks to be performed:

1. As described in ORA Supplemental Testimony,[259] require the Commission's Energy Division to oversee an audit of PSEP to identify and resolve accounting irregularities to ensure cost data collected for VIPER can be used to improve future cost forecasts;[260]

2. Require PG&E to collect cost data consistent with the finding of the recommended PSEP audit;

3. As described in Section 7.6.5.2 above, PG&E's has not clearly defined the threat to be mitigated through VIPER, nor that it is able to quantify the threat for specific pipeline sections such that VIPER projects can be accurately prioritized. PG&E should address these issues to the satisfaction of the Commission and parties before ratepayer funding is approved;

4. As described in Sections 7.1.1 and 7.6.5.4 above, require PG&E to complete deferred PSEP work before starting VIPER, thus permitting PG&E the time to adequately address VIPER Program deficiencies; and

5. As described in Section 7.1.2 above, require quarterly reporting by PG&E similar to the PSEP Quarterly Compliance Reports, with supplementary information to ensure the appropriate scope of work is completed and to better inform future forecasts.

As an example, consider mercury. PG&E has documented high levels of mercury in its pipelines as a driver of higher hydrotest costs, but nowhere does it discuss the regulations of mercury emissions in homes and businesses when the mercury-laden gas is combusted. PG&E had ideas about how the mercury got in the lines, but no proof. If this mercury was in a water pipeline, it would be a different story, as Safe Water Drinking Act (SWDA) includes clear standards for inorganic chemicals such as mercury. The point here is not to compare the actual consequences of mercury in gas vs. water, but to note that intrusions of regulated chemicals into water lines is significant, and necessitates costs during pipeline construction and replacement.

[259] Ex. ORA-47 (Supplemental Testimony, Roberts).

[260] Ex. ORA-47 (Supplemental Testimony, Roberts), Section V, pp. 20-23.

In addition, as described in Section 7.1.1 above, any decision in this proceeding should include a mechanism to ensure work is performed as proposed by PG&E.

With regard to this last proposal (and ORA's fifth proposal in support of quarterly reports), ORA notes that Indicated Shippers provides two alternatives to ORA's proposal for the Commission to adopt a VIPER budget of $110.0 million as opposed PG&E's request for $193.8 million. One calls for full deferral of program costs pending a reasonableness review. The second proposes that PG&E be compensated at adopted PSEP levels, with additional compensation where proven to be reasonable.[261] While ORA continues to endorse its own forecast, it strongly supports one element of the Indicated Shippers' alternative proposal: that PG&E be required to accurately and completely document the scope of work performed.[262] This is the same point intended by ORA's request that any final decision identify specific work that PG&E must perform, and ORA's request for quarterly reporting. Both of these mechanisms will serve to ensure that PG&E performs the work it proposes, and that data is collected to better inform cost forecasting in future rate cases.

7.7 Geo-Hazard Threat Identification and Mitigation

7.8 Programs to Enhance Integrity Management

7.9 Valve Automation

7.10 Public Awareness

Public Awareness programs cover PG&E's expenditures to notify customers about natural gas issues. This includes a triennial letter campaign to customers within 2,000 feet of PG&E's transmission system due to a PG&E commitment to Congresswoman Jackie Speier after the San Bruno disaster.[263] There is no basis for ratepayer funding of

[261] Indicated Shippers Opening Brief, pp. 142-145.

[262] Indicated Shippers Opening Brief, p.144.

[263] PG&E OB, p. 7-51.

this measure in state or federal law. PG&E is voluntarily undertaking this measure in an effort to make amends for its imprudent management of its gas transmission system, and therefore PG&E shareholders should continue to pay for these communications, not ratepayers.

7.11 Inoperable and Hard-to-Operate Valves

7.12 Class Location Program

PG&E's Class Location Programs monitors class location changes along its gas transmission system, and takes action when class location increases occur. Thus, the program has two elements: studies and mitigation. Mitigation required to respond to a class location increase may include pressure testing, pipe replacement, or a decrease in pressure.[264]

One of the primary differences between PG&E and ORA regarding this program is the unit costs for the class location hydrotests. PG&E proposes a unit cost of $2.2 million per mile for class location hydrotests – more than double its unit cost forecast for its Hydrotest Program discussed in Section 7.4 above. PG&E justifies this significant difference in unit cost forecasts for the same type of work on the basis that class location hydrotests will be significantly shorter than the tests performed in its Hydrotest Program discussed in Section 7.4 above. ORA analysis shows that $1.1 million per mile is a more reasonable and accurate forecast for class location hydrotesting.

PG&E's Opening Brief challenges ORA's class location hydrotest forecast on two bases:

1. "ORA's analysis ignores relevant historic unit and unit cost data…"[265]
2. ORA "fails to consider the differences in strength test projects between those required to address class location changes and those included in PG&E's overall Hydrostatic Testing Program."[266]

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[264] See 49 CFR § 192.611.

[265] PG&E OB, p. 7-56.

[266] PG&E OB, p. 7-56.

3. "ORA's recommendation on PG&E's Hydrostatic Testing Program unit cost is fraught with errors, and is not reliable."[267]

These arguments side-step the facts in the record.

As an initial matter, PG&E is required under D.11-06-017 to pressure test or replace all pipelines not previously tested for at least one hour. This is the reason for its Hydrotest Program described in Section 7.4 above. However, PG&E's Class Location Program forecast fails to acknowledge that as a result of this hydrotesting requirement, the number of pipeline miles requiring hydrotests as mitigation in the Class Location Program should diminish over time.

Regarding PG&E's first complaint, ORA did not "ignore relevant historic unit and unit cost data." Rather, ORA found PG&E's use of data from 2000 to 2005 to be evidence of "cherry picking" given the availability of more current hydrotest data.

Regarding PG&E's second complaint, PG&E's Rebuttal Testimony explains how class location hydrotesting differs from the tests performed in its Hydrotesting Program discussed in Section 7.4.[268] Specifically, PG&E's witness claims that the testing between the two programs "is distinct and not fully comparable." He explains that class location hydrotesting is "composed of shorter segments of pipeline" and larger diameter pipeline, and that the short lengths result in unit costs heavily influenced by fixed costs.[269] Specifically, he identifies the average length of class location hydrotests to be "0.25 miles on average compared to over 2 miles on average" for the Hydrotest Program.

There are a number of problems with PG&E's attempts to distinguish class location hydrotests from those in the Hydrotest Program. First, while fixed costs may be a significant cost driver for short hydrotests, PG&E contradicts itself regarding the average length of a class location pressure test. PG&E states in its Rebuttal Testimony

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[267] PG&E OB, p. 7-56.

[268] PG&E OB, pp. 7-56 to 7-57, quoting Ex. PG&E-39, p. 4B-6, lines 4-16.

[269] PG&E OB, pp. 7-56 to 7-57, quoting Ex. PG&E-39, p. 4B-6, lines 4-16.

that the average length is 0.25 miles,[270] yet the cost justifications provided in its Opening Testimony are based on projects just over 1.0 miles long.[271]

Second, PG&E fails to provide any other "facts" – other than contradictory length comparisons – to support the difference between its 2013 unit cost forecast of $0.97 million per mile for its Hydrotest Program and its $2.2 million per mile forecast for performing the same work in its Class Location Program. For example, while PG&E's Rebuttal Testimony discusses the relationship between fixed and unit costs, PG&E fails to identify what those costs are to demonstrate the validity of its bald assertion.[272] Consider, by comparison, ORA's analysis in Section 7.4.3.3 of its Opening Brief, exploring the relationship between fixed and variable hydrotest costs based on PG&E's $925,000 fixed cost PSEP hydrotest forecast.

PG&E bears an affirmative obligation to support its forecast, but fails that obligation by withholding critical cost information.

Third, PG&E's failure to provide consistent information regarding the length of its pressure tests between the Hydrotest Program and the Class Location Program make comparisons across the programs – and therefore justification for their wildly different unit cost forecasts – nearly impossible. However, to the extent class location hydrotests are "short," we can compare them to the hydrotests PG&E performed in 2014 in its PSEP hydrotesting program. PG&E's witness testified that in 2014 PG&E conducted pressure tests on "mini projects, short in length"[273] with actual unit costs of "$1.2 million a mile."[274] Therefore, while PG&E represents its $2.2 million per mile forecast for "short"

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[270] Ex. PG&E-39, p. 4B-6.

[271] Ex. PG&E-1, p. 4B-9.

[272] The relationship between fixed and variable hydrotest costs is discussed in ORA's OB at § 7.4.3.3.

[273] 17 RT 1736:17 (Barnes/PG&E).

[274] 17 RT 1736:25-26 (Barnes/PG&E).

class location hydrotesting is reasonable, ORA's forecast of $1.1 million per mile is closer to what PG&E actually experienced for "short" projects in this period.[275]

Regarding PG&E's third claim, ORA's recommendations regarding the Hydrotest Program forecast are not "fraught with errors."[276] As reflected in its Opening and Supplemental Testimony, and in its Opening Brief, ORA extensively and meticulously studied and analyzed nearly every element of PG&E's Hydrotest forecast that it was possible to analyze given the dearth of data provided by PG&E. PG&E has not identified a single "error" in that data or analysis. Rather, PG&E mistakes differences of opinion with "errors."

[275] ORA notes that for many other reasons, as discussed in Section 7.4 of its OB, and generally in the testimony of Tom Roberts, the cost per mile for longer tests is far lower than PG&E suggests for its pressure test program.

[276] PG&E OB, p. 7-56.

7.13 Water and Levee Closing Program

7.14 Shallow Pipe Program

7.15 Gas Gathering Program

7.16 Work Required By Others Program

8 Storage

8.1 Overview and Summary

8.2 Stipulation Between PG&E and ORA

8.3 Comments

9 Facilities

9.1 Overview and Summary

9.2 ECA Phase 1

9.3 ECA Phase 2

9.4 Hydrostatic Testing

9.5 Critical Documents

9.6 Data Acquisition and Metric Development

9.7 Physical Security

9.8 Becker System Upgrades

9.9 Gas Quality Practice Assessment

9.10 Gill Ranch

9.11 Routine Expense

9.12 Burney K-2 Compressor Replacement

9.13 Los Medanos K-1 Compressor Replacement

9.14 Compressor Unit Control Replacements

9.15 Upgrade Station Controls

9.16 Emergency Shutdown System Upgrades

9.17 Rebuild Santa Rosa Compressor Station

9.18 Upgrade Pleasant Creek Processing Facilities

9.19 Gas Transmission Electrical Upgrades-Hinkley and Topock Compressor Stations

9.20 Gas Transmission Electrical Upgrades – Compressor Stations (excludes Hinkley, Topock, Santa Rosa)

9.21 Physical Security

9.22 Hinkley Compressor Unit Retrofit Project

9.23 Install Active Fire Suppressions Systems

9.24 Perform Simple Station Rebuilds

9.25 Perform Complex Station Rebuilds

9.26 Perform Transmission Terminal Upgrades

9.27 SCADA Visibility

9.28 Replace Obsolete Bristol Controllers

9.29 Replace Obsolete Limitorque Valve Actuators

9.30 Electrical Upgrades Program

9.31 Biomethane Interconnects

9.32 Routine Capital Spending

10 Corrosion Control

10.1 Overview and Summary

PG&E has attempted to define the issue of how the Commission should determine the reasonable level of spending for PG&E's dramatically increased request for corrosion control costs for contacted casings on overly narrow interpretations of Commission decisions regarding "deferred maintenance," rather than the underlying standard for ratemaking and for assessing utility decisions, reasonableness.[277] PG&E has had minimal levels of corrosion control measures and spending over the past decade, with slightly increased levels of spending in the previous rate case cycle, and now requests over ten times the expense level and five times the capital level of spending of its 2012 actual levels,[278] to meet what PG&E asserts is a newly recognized, higher risk of corrosion than had been recognized in the past, based on events from 2007 and 2009.[279] PG&E has had numerous audits and internal reports suggesting, however, that PG&E's past practices were deficient. PG&E maintains it was reasonable to have performed such little maintenance in the past, despite these audit reports, and also reasonable now to rapidly make up for the backlog of contacted casings, and other work that has apparently been delayed for years.

Corrosion is a problem that grows over time, also known as a time-dependent threat.[280] PG&E's own internal safety audits found problems with PG&E's practices,

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[277] *See supra* ORA discussion in Sections 3 and 3.1.

[278] PG&E OB, p. 10-2, states they are requesting $99 million in expense in 2015, an increase from $8.4 million of 2012 spending, and $49 million in capital spending, an increase from $8.2 million of 2012 capital spending.

[279] PG&E OB, p. 10-26.

[280] *See, e.g.,* PG&E-1, p. 7-8 ("American Society of Mechanical Engineers (ASME) B31.8S classifies corrosion as a 'time-dependent' threat because it occurs and can become more aggressive over time.")

even in this period where PG&E claims corrosion was not considered a significant threat. This leads to the need for the drastic level of catch-up work in the test year and rate period, and more work in total, than there would have been had PG&E been taking care of this issue properly and reasonably over the last decade. PG&E even admits to its responsibility for costs for non-compliance, and excludes such costs from this proceeding, although because PG&E claims it is not seeking recovery of these costs it does not provide any proof of these costs.[281] But ORA's request for shareholder responsibility is somehow strictly prohibited because in the past 2011 GT&S proceeding, when PG&E requested "$500,000 annually to mitigate one casing" in expenses and no specific capital funds[282] they did not specifically forecast any of the specific costs it now requests for $48.5 million in 2015 expenses an $21 million in 2015 capital. PG&E then assumes that this is the only definition of "deferred maintenance" that the Commission can adopt for purposes of disallowances. Regardless of whether or not ORA's recommended disallowance is based on "deferred maintenance" or an unreasonable approach to corrosion, the Commission has ample justification to exclude certain corrosion costs from recovery per the recommendations of ORA, and other parties.

10.1.1

10.1.2

10.1.3 The Commission Can Disallow Forecast Corrosion Costs Even If Such Costs Were Not Funded Previously In Rates

PG&E argues that because it claims to have not previously included costs for its forecasted corrosion control activities in rates in prior rate cases, the Commission apparently cannot find any of its proposed costs to be the responsibility of shareholders for any reason, and cross-references its arguments in Section 3.1.6.[283] ORA submits that

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[281] See PG&E OB, Section 10.1.5, pp, 10-15 to 10-21.

[282] PG&E OB, p. 10-27, citing Ex. PG&E-40, p. 7-33.

[283] PG&E OB, p. 10-7.

its arguments regarding "deferred maintenance" and unreasonable PG&E management forecasts in Section 3.1.6 above establish much broader authority for the Commission to make such disallowances, including in the cases PG&E itself cited, than PG&E's arguments acknowledge.

10.1.4

10.1.5 PG&E Cannot Prove It Has Excluded Any Level of Costs, Or That Such Costs Represent All Work To Remediate Past Non-Compliance, Or Any Other Argument It Has Offered Dependent Upon Excluding Such Costs, But This Admission Contradicts PG&E's Criticisms of Parties' Recommended Reductions On the Basis of PG&E's Past Unreasonable Actions

10.1.5.1 PG&E's Proof To Exclude Costs For Work Purportedly Needed To Remediate Existing Non-Compliance Was Non-Existent, And Thus PG&E Applied Opaque Criteria To Exclude Such Work

PG&E notes that "[a]lthough, as discussed below in Section 10.1.6, there is no ratemaking rule that prohibits cost recovery to bring a utility's practices or system into compliance with applicable regulations, PG&E chose not to seek rate recovery for the costs to remediate existing compliance issues."[284] However, PG&E provided no proof for the level of these costs.[285] PG&E tacitly admitted (even if it explicitly denied doing so) by excluding such costs from recovery that the Commission had the authority, if not the mandate, to deny PG&E recovery of forecast corrosion control costs for costs to remedy past non-compliance. The Commission has the authority to deny PG&E recovery of any costs resulting from past unreasonable PG&E maintenance activity levels.

10.1.5.6 PG&E's Burden To Prove Its Forecast Reasonable Includes Providing Proof For the Costs PG&E Excludes To Support All PG&E Arguments Relying Upon the Existence and Level of Such Excluded Costs

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[284] PG&E OB, p. 10-15.

[285] PG&E OB, p. 10-19.

PG&E repeatedly relies upon the existence and level of the costs it claims it excluded from recovery for corrosion control for past non-compliance to support numerous arguments it offers to support the reasonableness of the level of costs it did include in its corrosion control forecast. Yet PG&E amazingly states the following:

> PG&E has the burden of proving that the costs **in** its forecast are reasonable. PG&E has no burden to prove anything about the cost of work **not** in its forecast. The process that PG&E used to determine what not to seek recovery for is irrelevant to the determination of reasonableness of PG&E's forecast. All that is relevant is what PG&E ultimately chose to include in its forecast.[286]

PG&E only has no burden to prove anything about the cost of work not in its forecast if it is not relying on the existence and level of such costs to support arguments for the cost level of the projects PG&E ultimately included in its forecast. But PG&E does rely on the level of such costs in making its arguments in support of its forecast. PG&E also relies upon the level of such costs in criticizing ORA's reductions for excluding such costs, when requesting inclusion of such costs in ORA's calculations would lead to recovery of such amounts, in contradiction of PG&E's contention that it failed to provide sufficient proof for recovery of these costs.

10.1.6 If the Commission Finds PG&E Should Have Reasonably Performed Earlier Some Work Now Forecast, A Disallowance Is Warranted Regardless of Whether The Work Was Previously Funded

As discussed above in Section 3, the Commission is not limited in its cost categories to justify disallowance of cost recovery to costs for work previously forecasted and approved in a rate case, and then not performed and requested again in a subsequent rate case. PG&E's contention that "no disallowance is warranted unless the work was

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[286] PG&E OB, p. 10-19 (emphasis in original).

previously funded by customers"[287] does not fairly represent Commission authority to review all utility actions contributing to costs included in rates for reasonableness.

10.2 Casings

10.2.1

10.2.2 PG&E's Increase Remediated Contacted Casings Starting From 1 One Casing In 2011 To 9 Casings In 2014 Does Not Prove PG&E Acted Reasonably Or Appropriately Responded To Internal Audit Reports In Requesting To Remediate 117 Casings In 2015

PG&E is requesting cost recovery for mitigation of 117 contacted expense casings in 2015 (111 to remediate contacted casings to clear the backlog of 335 casings in three years, and 6 for newly identified contacted casings), based on a contacted capital casings forecast for 2015 of 36.[288] PG&E mitigated 2, 4, and 9 contacted expense casings from 2011 – 2013, after mitigating 1 expense casing per year from 2007 – 2010.[289] PG&E asserted it "responded appropriately" to a critical 2010 audit report by increasing its mitigation levels in this fashion.[290] PG&E characterizes this increase as doubling every year from 2010-2014.[291]

As impressive as this annual doubling increased level seems, PG&E's request to increase the number of requested contacted casings from 9 in 2014 to a requested 117 in 2015 represents a far larger increase. The rate of change in 2012-2014 was inadequate to address PG&E's corrosion control problems identified in a critical audit in 2010, which itself occurred after the events in 2007 and 2009 that PG&E claims led to increased standards to combat contacted casings. Even if PG&E further doubled

[287] PG&E OB, p. 10-21.

[288] Ex. PG&E-1, p. 7-37.

[289] PG&E OB, p. 10-28.

[290] PG&E OB, p. 10-28.

[291] PG&E OB, p. 10-28.

its 2014 level of 9 every year for 3 more years, it would not reach the level it requests for 2017.

10.2.3 PG&E Has Not Established It Complied With Applicable Regulations Concerning Contacted Casings Or That Its Actions Were Reasonable

10.2.3.1 PG&E's Own Workplans Adopted PHMSA's Enforcement Guidance And Made Compliance Mandatory Rather than Optional, And Even If PG&E Only Failed to Do What It "Should" Its Actions Are Unreasonable

In Section 10.2.3.2 of its OB, to which ORA responds below, PG&E argues "PG&E Complied With the PHMSA Enforcement Guidance" by noting that "PG&E's Work Procedure WP4133-04 is a 'plan of action' for mitigation of contacted casings,"[292] and that PG&E initiates this plan of action by performing a first step, a risk assessment, within six months of identifying a "potentially contacted casing."[293] PG&E has WP4133-04 references "Numbered Document O-16"[294] which states:

> Cased pipeline crossings that are found to be contacted (the casing is in electrical contact with the pipeline) shall be reported to corrosion engineering personnel within 30 days of discovery of the contact.[295]

As ORA discussed in Section 10.2.4.1 of its OB, PG&E claimed that it previously followed PHMSA Guidance #PI-94-022 and PG&E GT&S Standard S4126 which required the initiation of a corrective action plan within six months. By adopting these plans, PG&E was bound to follow them,[296] regardless of whether or not the PHMSA guideline it claims to follow now only says "should" rather than "must" with respect to initiation of a plan for corrective action within six months of discovering the contact.

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[292] PG&E OB, p. 10-33.

[293] PG&E OB, p. 10-34.

[294] Ex. PG&E-44 (PG&E Rebuttal Appendix A/Armato), p. A-159

[295] Ex. PG&E-44 (PG&E Rebuttal Appendix A/Armato), p. A-167, General Requirement 4. G.

[296] 49 C.F.R. § 192.605(a) requires operators to "prepare and follow … a manual of written procedures for conducting operations and maintenance activities and for emergency response. " 49 C.F.R. §§ 192.605(b) and (b)(2) require the manual to "include procedures" for "[c]ontrolling corrosion in accordance with the operations and maintenance requirements of subpart I of this part."

PG&E's argument that the initiation of a plan of action "should" rather than "must" be initiated within six months is based on the 1986 enforcement guidance, although #PI-94-022[297] and the most recent and currently applicable PHMSA Part 192 Enforcement Guidance[298] clearly state this requirement is mandatory, as a violation exists if a plan is not started within six months. Assuming *arguendo* that PG&E is correct, however, that it only **should** have rather than **must** have initiated corrective action plans within six months of discovering a contacted casing.[299] Assuming[300] additionally for the purpose of the argument that PG&E did not initiate such corrective action plans within six months, ORA submits PG&E's failure to do what it admits it **should** have done but did not do is unreasonable and grounds for a disallowance. The remediation of contacted casings is work that PG&E is now proposing a ten-fold acceleration over their current pace of work, and to remediate **all** contacted casings within three years. PG&E is denying the mandatory applicability of this timeline for an alternative reaction to mitigating the contacted casing when its own internal plans have required this timeline and when PG&E is attempting to convince the Commission and the public PG&E is committed to making safety its highest priority. PG&E is arguing that it might not undertake particular alternatives to stricter safety measures if PG&E believes they are not required but only recommendations. Even when PG&E formally adopts such recommendations, an action that should bind PG&E to meeting such standards, PG&E does not consider themselves bound to follow them.

[297] PG&E-40, Chapter 7, Attachment D, pp. 7-AtchD-2 to 7-AtchD-3, Section 3; see ORA OB, pp. 137-138 & fn. 573.

[298] Ex. ORA-69, p. 78, "Enforcement Guidance, Examples of a Probable Violation".

[299] See PG&E OB, pp. 10-31 to 10-31.

[300] ORA notes below in Section 10.2.3.2 that PG&E cannot show that it initiated a corrective plan of action within six months.

10.2.3.2 PG&E Did Not Comply With PHMSA Enforcement Guidance, As PG&E Cannot Provide The Required Proof It Initiated Corrective Action Plans Within Six Months Because PG&E Failed Even to Record the Date PG&E Initially Discovered A Contacted Casing

Although PG&E denies it has to comply with the PHMSA Enforcement Guidelines, including guidelines requiring PG&E to initiate corrective action plans within six months of discovering a contacted casing, PG&E does argue it has complied with those Guidelines. Interestingly, PG&E mostly offers WP4133-04 as proof it has complied with PHMSA Enforcement Guidance,[301] as well as the absence of any finding by PHMSA or CPUC auditors that PG&E's program was out of compliance.[302] But in Section 10.2.4.1 of its Opening Brief, ORA noted that PG&E failed to keep records of when PG&E discovered a contacted casing, explaining that "[b]ecause the applicable regulations do not specify a time frame within which corrective action, or corrective action plans, must be initiated, PG&E does not have a practice of tracking the date when PG&E initiates a corrective action plan."[303] As noted above, PG&E's internal requirements, even before the initiation of corrective action within six months, require reporting within 30 days of discovery of the contacted casing to "corrosion engineering personnel." PG&E cannot show that it can meet its own standards without these mandatory written records.[304] PG&E's only evidence that they met this requirement is an uncorroborated, conclusory statement in a data request.[305]

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[301] See PG&E OB, pp. 10-33 to 10-34.

[302] PG&E OB, p. 10-35.

[303] Ex. ORA-138 (ORA DR 130 Q1, and Attachments 1 and 2), pp. 1-2, *cited* in ORA OB, p.140 and fn. 579.

[304] 49 C.F.R § 192.491 requires that operators maintain records to demonstrate the adequacy of corrosion control measures or that a corrosion condition does not exist.

[305] Ex. ORA-138 (Response to ORA DR 130 Q1 (b): "That corrective action plan is initiated within six months of identifying a potentially contacted casing."

10.2.4 If The Commission Today Finds That PG&E Was Required By Regulation to Mitigate Its Contacted Casings Prior to 2015, Full Cost Recovery Would Be Unreasonable

PG&E argues that "even if the Commission today finds that PG&E was required by regulation to mitigate its contacted casings prior to 2015, cost recovery is still appropriate," again arguing that if costs were not specifically identified in a prior rate case, they cannot be disallowed for recovery as deferred maintenance, consistent with Section 3 of its OB.[306] ORA again refers to Section 3, above, of this Reply Brief, discussing the general standard of reasonableness and broader definitions of "deferred maintenance."

PG&E also argues that no one in any prior rate case "suggested that PG&E should mitigate contacted casings at a faster rate than it was."[307] PG&E bears the responsibility for maintaining its system and infrastructure. While some notice from other parties that its proposed maintenance was insufficient might have been useful to notify PG&E, other parties are not required to request what future reasonable responses PG&E must take to address problems which PG&E downplays. PG&E has the responsibility of spending above its authorized revenue requirement where necessary to meet safety mandates. PG&E's overall actions in failing to address casings much at all for years but now requiring huge increases to deal with an urgent, top safety priority are unreasonable.

10.2.5

10.2.6 If PG&E Believes the Contacted Casings Mitigation Plan Could Be Conducted In a More Measured Fashion and Meet Statutory Requirements, Its Risk Assessment Must Quantify The Risks in Terms of Risk Reduction Per Dollar Spent, And Its Application Should Have Included This Lower Cost Level

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[306] PG&E OB, pp. 10-37 to 10-38.

[307] PG&E OB, p. 10-38.

PG&E recommends that the Commission could instruct PG&E "to slow down the pace of those programs that PG&E determines reduce risk the least,"[308] even though "PG&E believes the risks justify the costs"[309] of its casings program. Because of the lack of quantification of risk reduction per dollar, however, PG&E could not fulfill this request if the Commission made it. ORA recognizes that slowing down the pace of a requested program, whether the intent of the program was to improve safety or for other system benefits, has been a common recommendation by parties including ORA in past GRCs and other ratesetting proceedings. Given the current heightened emphasis on safety, ORA finds this recommendation inconsistent with PG&E's current spending justifications. If PG&E believed a slower pace for casings mitigation could be achieved while maintaining a safe system, it should have offered such an approach in its application, even if only as an alternative proposal.[310] The 2014 GRC decision, D.14-08- 032, requires PG&E to apply "as low as reasonably practicable" (ALARP) principles to its rate forecasts for safety measures and show that a proposed approach is the most cost-effective.[311] PG&E has criticized the application of ALARP,[312] and in only now offering this alternate proposal for slower mitigation without any analysis as to its impact on safety still fails to reasonably assess the cost-effectiveness of its proposals.

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[308] PG&E OB, p. 10-39.

[309] PG&E OB, p. 10-39.

[310] PG&E took this approach in justifying the approach of its In-Line Inspection program, *see* Ex. PG&E-1, pp. 4A-15 to 4A-19.

[311] D.14-08-032, p. 28.

[312] Ex. PG&E-37, p. 20-21.

10.3 AC Interference

10.3.1 ORA's Policy Argument Is Supported By PG&E's Own Statements, And Correctly Fails to Exclude For Costs PG&E Purportedly Excluded

10.3.1.1 ORA Correctly Did Not Account For PG&E's Purported Excluded Costs To Prevent PG&E Recovery Of Such Costs, In Accordance With PG&E's Admission That PG&E Provided No Evidence In Support of Such Costs Because PG&E Was Not Seeking Recovery of Such Costs

As ORA has noted above in Section 10.1.5.6 , PG&E has offered no proof of the level of costs PG&E claims to have excluded from recovery, and claims not to need to offer such proof because it is not requesting such money. However, PG&E still criticizes ORA's recommended disallowances for not considering PG&E's voluntary exclusion of "*remedial costs*."[313] While PG&E does not offer any proof of the level of the excluded costs, and claims it should not recover such costs, PG&E nonetheless claims "the total forecast for all corrosion mitigation costs (other than casings) is *really* $32.8 million."[314] PG&E asserts that "ORA's methodology, applied to the full forecast[315] would thus result in no reductions to PG&E's request."[316] If the Commission were to adopt ORA's methodology, and then compare reductions under ORA's approach not to consider the costs excluded from recovery for which PG&E offers no proof, with reductions under PG&E's approach to include the excluded costs, PG&E's approach effectively provides for recovery of the excluded costs. PG&E has already admitted that it cannot meet its burden of proof for recovery of such costs. ORA properly excluded consideration of these excluded costs from its recommendation for a partial disallowance

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[313] PG&E OB, p. 10-43 (emphasis in original).

[314] PG&E OB, p. 10-43 (emphasis added).

[315] "Full forecast" includes the excluded costs.

[316] PG&E OB, p. 10-44.

10.3.1.2 PG&E's Opening Brief Is Based On An Inaccurate Premise

10.3.1.2.1 PG&E's Consultant Correctly Found PG&E Had No Written Plan to Identify, Test For and Minimize Stray Currents, And O-16 Is Not Such a Plan

PG&E "recognizes that its consultant, Exponent, concluded that PG&E did not have a written plan to identify, test for and minimize the effects of stray currents."[317] The only evidence PG&E offers is that its Guidance Document O-16 is the "written plan to minimize the detrimental effects of AC interference."[318] The complete subsection that PG&E partially cited states in full:

> Where stray currents from non-PG&E protection systems, both cathodic and anodic, are detrimentally affecting the cathodic protection of PG&E gas lines, contact the non-PG&E facility owners and take corrective measures to mitigate or eliminate the stray current condition. Non-PG&E protection systems may include pipelines, transit systems, telluric earth currents, etc. When other's facilities are to be installed near existing PG&E gas-carrying facilities and these foreign facilities are likely to cause interference to PG&E's gas-carrying facilities, then the other party should be contacted and before-and-after readings should be taken regarding PG&E's facilities. If interference is encountered on distribution lines, the third party must be informed of the interference and be required to correct it. If interference is encountered on transmission lines, contact corrosion engineering personnel. This investigative work should be charged to WRO expense.[319]

This document is not "a written plan to identify, test for and minimize the effects of stray currents," as it only requires PG&E to contact 3rd parties to take care of issues regarding stray currents, without any specific mention of how personnel of 3rd parties or even PG&E would "identify, test for and minimize the effects of stray currents."

Such a fact is definitely relevant in assessing whether PG&E's current forecast is reasonable, regardless of whether the levels in such forecast are increased due to "deferred maintenance" or general unreasonable maintenance activities.

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[317] PG&E OB, p. 10-45.

[318] PG&E OB, p. 10-44.

[319] Ex. PG&E-44, p. A-163, O-16, p. 4, General Information 2.J.

10.3.1.2.2 PG&E's Workpapers State "The Planned Amount of Grounding Is Based On Historical Design Of This Transmission Line and Assuming 50% of the Original Equipment Is Failing" But If These Workpapers Are Not Based On PG&E's Current Forecast But Assumptions of What a Forecast Will Find, They Are Not Supported

PG&E claims that the meaning of the statement in a workpaper that "the planned amount of grounding is based on historical design of this transmission line and assuming 50% of the original equipment is failing"[320] was only meant to convey that "PG&E has forecast *that a study will find* that half of its mitigation measures are 'failing.'"[321] Based on this clarification, PG&E cannot meet its burden of proof that its forecasted amounts are reasonable, because these amounts are *a forecast of a forecast* of costs rather than a reasonable forecast itself.

10.3.2 PG&E Offers No Support For Setting A Threshold Level For Workpapers To Support Cost Recovery At $1 Million

In justifying its failure to provide workpapers to support costs for projects or programs with forecast costs lower than $1 million, PG&E claims "[t]here is no Commission requirement to provide workpapers, much less to do so for every cost in a forecast."[322] PG&E is required to meet its burden of proof, and while for practical purposes every cost will not have workpapers, an arbitrary, PG&E-established $1 Million threshold without any citation to Commission decisions or actions where anything close to such a threshold was adopted is unsupported and unreasonable. For costs that are over a half a million, as PG&E requests here, the citation to portions of PG&E testimony and a table[323] do not substitute for workpapers.

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[320] Ex. PG&E-9, p. WP 7-84.

[321] PG&E OB, p. 10-46.

[322] PG&E OB, p. 10-47.

[323] PG&E OB, pp. 10-47 to 10-48 and Fn. 270, *citing* Ex. PG&E-1, p. 7-27 to p. 7-32 and Table 7-9.

10.4 DC Interference

10.4.1 ORA's DC Interference Methodology Correctly Considers Excluded Costs For The Same Reasons AC Interference Methodology Correctly Considers Excluded Costs

PG&E offers similar criticisms of ORA's DC Interference methodology as it does for AC Interference.[324] ORA reiterates that its discussion of and support for AC Interference methodology, which did not consider costs PG&E excluded from recovery from this proceeding and did not provide any support for the level of such costs, is equally valid for DC Interference.

10.5 Atmospheric Corrosion

PG&E notes that ORA's recommendation regarding atmospheric corrosion is the same as for AC and DC Interference, and that PG&E's arguments regarding deferred maintenance apply here.[325] ORA has provided arguments above regarding AC and DC interference and deferred maintenance that apply here as well.

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[324] PG&E OB, p. 10-53.

[325] PG&E OB, p. 10-59.

10.6 Cathodic Protection Systems

10.7 Coupon Test Stations

10.8 Internal Corrosion

10.9 CP Rectifier, Monitoring, Resurveying, Troubleshoot

10.10 Corrosion Investigations

10.11 Close Interval Survey

11 Gas Transmission Operation and Maintenance Activities

11.1 Overview and Summary

11.2 Locate and Mark

11.3 Pipeline Maintenance

11.4 Station Maintenance

11.5 Transmission Expense Projects

11.6 Stanpac

12 Other GT&S Support Plans

12.1 Overview and Summary

12.2 Buildings and Process Safety

12.3 Environmental

12.4 Habitat and Species Protection

12.5 Hazardous Waste Disposal and Transportation Costs

12.6 Research and Development Costs

12.7 Customer Access Charge Costs

12.8 Tools and Equipment

12.9 Building Management Expenditures

13 Gas System Operations

13.1 Overview and Summary

13.2 Gas Systems Operations Staff

13.3 Normal Operating Pressure Reductions

Normal Operating Pressure reductions are voluntary measures that PG&E is taking to lower pressures on its transmission system so that both operations and overpressure protection are set below the Maximum Allowable Operating Pressure of the pipeline, rather than PG&E's historical practice of setting the over pressurization point above MAOP.

PG&E's forecast for Normal Operating Pressure reductions should be rejected. PG&E admits in its opening brief that ORA's calculations for cancelled NOP projects were correct.[326] PG&E then states that "there are other programs for which PG&E's

[326] PG&E OB, p. 13-6.

forecasts have increased since PG&E's 2013 rate case filing. For example, PG&E has identified a significant amount of emergent New Capacity work since it made this filing."[327, 328] Since PG&E does not contest that the amount of NOP projects has been reduced since it made its forecast,[329] PG&E's forecast for NOP should be rejected, and ORA's 2015 forecast of $2.3 million should be adopted.

13.4 Network Investment Plans

13.5 New Business

New Business covers the costs of serving large new customer loads. ORA recommends significant reductions to PG&E's forecasts. In summary, as Mr. Christopher stated during cross examination:

> [Mr. Bromson]: So at least it's ORA's understanding that we put forth an average that used the same 2011, 2012, and 2014 numbers as PG&E did, but just substituted the 1.309 actual 2013 figure for the 7.003 million 2013 forecast figure that PG&E used. Can you accept that subject to check at least?
> [Mr. Christopher]: I can accept that. I was wrong.[330]

Both of the major residential projects PG&E described under new business have been determined to be "unlikely to be built" and PG&E confirmed that their reduction was not based on this unlikeliness of the project to move forward.[331] ORA's analysis for new business is based on the most current information, rather than PG&E's forecast where PG&E "may spend more for new business than what we've asked for in this

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[327] PG&E OB, p. 13-6.

[328] ORA also disagrees with PG&E's New Capacity work projects, as discussed in Sections 13.5 and 13.6 below.

[329] PG&E OB, p. 13-6. "ORA's recommendation for reduced funding is based on the fact that six out of the fourteen NOP reduction projects identified in the rate case had been cancelled as of June 15, 2014. This fact, however, should not be dispositive."

[330] 25 RT 3204:22 to 3205:2. Also see generally, 25 RT 3205 – 3208.

[331] 25 RT 3207:24 to 3209:25.

case."[332] Based on the record, the Commission should adopt ORA's forecast, and reject PG&E's forecast.

13.6 Capacity Projects

Capacity Projects cover upgrades to PG&E's existing infrastructure in order to meet forecast capacity needs based on new customers or increased gas demand from existing customers, but not driven by customer-specific demand growth.

PG&E has indicated that many of its capacity projects are either cancelled, in the early stages of work, or will come online late in this rate case period or even subsequent to the rate case period.[333] What PG&E plainly states in their opening brief is that, rather than potentially be subject to delayed capital cost recovery, PG&E would rather allow customers to have "uncontrolled customer outages"[334], "customer[s] losing service", or even the "risk of explosion".[335] As demonstrated through ORA's discovery most of the projects have been cancelled, delayed, or reduced in scope.[336]

PG&E also is attempting to shift into its capacity projects costs that should be borne by shareholders to remediate past PG&E imprudence. ORA notes that PG&E has moved into its 2015 emergent capacity work, projects on Line 300B, directly associated with PG&E's incorrect class location studies and pipeline operations since Line 300B was installed in the mid-1990s.[337] Ratepayers already paid for PG&E to correctly install and operate these lines nearly two decades ago. Ratepayers should not be held responsible for correcting PG&E's past imprudence, and the Commission should

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[332] 25 RT 3209:23-25.

[333] Ex. ORA-56, p. 37.

[334] PG&E OB, p. 13-12.

[335] PG&E OB, p. 13-13.

[336] Ex. ORA-71, pp. 172-174 and Ex. ORA-156.

[337] Ex. ORA-156. "The two projects are related to the Class Location OII []. These sections of L-300B were found to have been out of class since installation and were required to have their pressure reduced, which consequently reduced their capacity. These projects are designed to restore the capacity of L-300B."

examine PG&E's other work to make sure that PG&E is charging costs to ratepayers for PG&E's past imprudence and need for remediation on Line 300B or any other line.

13.7 Allocation of Storage Assets to Pipeline Load Balancing

13.8 Electricity Costs for Compressor Operations

13.9 Recovery of Greenhouse Gas Compliance Instrument Costs

13.10 Gill Ranch Storage's Proposal for Daily Balancing

14 Information Technology

15 Reporting Requirements and Program Management

16 Revenue Requirement Issues

16.1 Computational Matters

16.2 Taxes: NOL and Bonus Depreciation

16.3 Cost Recovery Issues

16.4 Post Test Year Ratemaking (PTYR)

16.5 Rate Base Depreciation

17 Rate Issues

17.1 Throughput Forecasts

17.2 Cost Allocation and Rate Design

17.2.1 Backbone Rate Design

17.2.2 Local Transmission Cost Allocation

Calpine Corporation ("Calpine") argues that the Commission should change PG&E's allocator or local transmission costs from cold year winter peak month in use throughout the life of the Gas Accord process to Cold Winter Day ("CWD") Throughput.

Calpine offers that "[s]uch a change would better reflect cost causation, as CWD more closely matches PG&E's design criteria for local transmission facilities."[338] Calpine further notes that "[t]he Commission has affirmed these cost causation principles on multiple occasions, including in Decision 03-12-061, issued after the last fully litigated GT&S rate case."[339] But in D.03-12-061, the Commission noted that PG&E proposed to maintain the Gas Accord structure for local transmission services.[340] The Commission stated that: "[l]ocal transmission costs were allocated to core and noncore customers using the cold year coincident peak month (*i.e.,* January) marginal demand measure adopted in the 1995 BCAP, D.95-12-053."[341] Despite any alleged affirmation of cost causation principles in D.03-12-061 that could supposedly justify use of CWD, D.03-12-061 noted the only concern regarding local transmission service raised by parties was payment by customers directly connected to the backbone, and that "[n]o one else opposes any other part of the proposal to continue the Gas Accord structure for local transmission services."[342] Decision 03-12-061 specifically adopted the current local transmission allocator that PG&E requests to maintain in this proceeding and cannot be construed as supporting use of a different allocator as Calpine does.

Cost allocation is not solely about adherence to any one aspect of cost causation, including design criteria. Calpine fails to provide Commission precedent supporting its recommendation to change PG&E's allocation methodology for local transmission costs, and the Commission should maintain PG&E's proposed allocator.

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[338] Calpine OB, pp. 30-31.

[339] Calpine OB, p. 31.

[340] D.03-12-061, p. 83.

[341] D.03-12-061, p. 249.

[342] D.03-12-061, p. 83.

17.2.3 Storage Rate Design

17.2.4 Transmission Level Customer Access Charges

17.2.5 Electric Generation Rate Design

17.2.6 Commercial Energy's Proposal to Modify the Noncore Customer Class Definition

18 Core Gas Supply

18.1 PG&E Core Gas Supply Proposals

18.1.1 Core Intrastate Pipeline Capacity

18.1.2 PG&E Firm Storage Capacity

18.1.3 Adjustments to 1-Day-in-10-Year Core Capacity Planning Standard

18.1.4 Changes to Core Procurement Incentive Mechanism

ORA supports PG&E's proposal for changes to the CPIM mechanism. As stated by the Core Transport Agent Consortium (CTAC), ORA "is qualified and well positioned to review proposed changes to the CPIM…"[343] ORA appreciates CTAC's confidence. If PG&E makes a proposal significant enough to warrant detailed ORA analysis and potential opposition, ORA will do so, consistent with ORA's mandate to represent all core ratepayers taking local transportation services from PG&E.

18.1.5 Pipeline Capacity Allocation Methodology

18.1.6 Incremental Storage Capacity Allocation

18.2 Core Transport Agent Issues

[343] CTAC OB, p. 10.

19 Proposals for Programs Directed Toward Small and Medium Sized Businesses

Respectfully submitted,

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