BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms. U 39 G	R.11-02-019 (Filed February 24, 2011)

PACIFIC GAS AND ELECTRIC COMPANY'S OPENING BRIEF

WILLIAM V. MANHEIM
KERRY C. KLEIN

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-3251
Facsimile: (415) 973-5520
E-Mail: KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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I. INTRODUCTION

PG&E urges the Commission to approve the gas pipeline upgrades and safety enhancements that are proposed in the Pipeline Safety Enhancement Plan ("PSEP"). This important work will make the gas system safer and more reliable for years to come; it will create an upgraded infrastructure that will support California's future growth; and it will maintain reasonable energy costs for California residential and business customers.

PG&E has demonstrated that its PSEP meets the Commission's new safety mandates to: (1) pressure test or replace all previously un-tested gas transmission pipelines in an orderly, efficient, and cost effective manner; (2) expand the use of automated shut-off valves, where appropriate; (3) validate the Maximum Allowable Operating Pressure ("MAOP") of gas transmission pipelines based upon pipeline features, and ensure that PG&E can meet the new "traceable, verifiable, and complete" standard on a going-forward basis; and (4) implement interim safety enhancement measures that apply to specific pipeline segments to enhance public safety prior to completion of pressure testing or replacement work.

PG&E's PSEP proposal is the most economical, least disruptive and safest way to create a next generation system. Phase 1 of the PSEP has been crafted to take advantage of economies of scale. It is less disruptive over the long run to make several upgrades to a pipeline at once rather than, for example, dig up a street twice. In addition, the requested funding for PSEP will be used only to meet these new safety mandates.

PG&E's Pipeline Modernization Program—designed to meet the Commission's new safety standard of pressure testing or replacing previously untested pipeline segments—relies on three Decision Trees developed by PG&E and vetted with industry experts to prioritize strength testing and replacement based upon known threats to the pipelines. By the end of Phase 1 of the Program (which runs from 2011-2014), all previously untested gas transmission pipeline segments in Class 2, 3 and 4 areas and Class 1 High Consequence Areas ("HCAs") operating with an MAOP above 30 percent, and all untested pipe segments determined to have a Manufacturing Threat, will either be strength tested or replaced. In addition, PG&E proposes to retrofit all pipelines operating above 30 percent Specified Minimum Yield Strength ("SMYS"), and many below 30 percent SMYS, to accommodate in-line inspection tools.

The PSEP also includes a Valve Automation Program that complies with the Commission's new mandate in Decision 11-06-017 to expand the use of automated shut-off valves, and Public Utilities Code Section 957, which requires the installation of automatic shutoff or remote controlled valves if the Commission determines those valves are necessary for the protection of the public. If the Commission approves the Valve Automation Program, the majority of gas transmission pipelines in populated areas in PG&E's service territory, including all of the larger diameter and higher pressure lines, will be able to be isolated more quickly in the event of a pipeline rupture, thereby facilitating emergency response.

PG&E's Pipeline Records Integration Program should be approved because it is a thorough, efficient and cost-effective means of meeting the new requirement of validating MAOP based on traceable, verifiable, and complete records, both now and in the future. The MAOP Validation Project will ensure compliance with the National Transportation Safety Board's ("NTSB") recommendation and Commission mandate to validate the MAOP for gas transmission pipelines through traceable, verifiable and complete records of pipeline features.

This standard has never before been required by federal or state regulations. The Gas Transmission Asset Management Project will build a system to ensure compliance with this new standard into the future.

The Commission also should approve PG&E's proposed interim safety enhancement measures, which consist of: (1) interim pressure reductions on certain pipeline segments until later corrective action (e.g. strength testing or replacement) can be taken; and (2) more frequent leak surveys and patrols for all Class 4, Class 3, Class 2, and Class 1 HCA pipe segments for which there are not complete pressure test records. These enhancements will ensure that the gas transmission pipeline system is safe until all previously un-tested pipe segments can be pressure tested or replaced.

PG&E's PSEP proposal included extremely detailed cost forecasts for each element of the PSEP. For example, each of the over 350 projects proposed as part of the Pipeline Modernization Program has a Project Summary Sheet (with a description of and justification for the project), a Project Cost Worksheet (showing the details of the cost estimate for that project), and a map showing the location of the project. The Pipeline Modernization cost forecasts are shown in three volumes of work papers. It is important to remember, however, that these forecasts can change based upon new information learned about pipeline segments, new environmental and permitting requirements, and other factors.

PG&E estimates that Phase 1 of the PSEP will cost approximately $2.2 billion. However, the amount that PG&E requests to recover in rates from customers during Phase 1 is significantly lower than the program expenditures for two reasons. First, PG&E proposes to have its shareholders absorb all program costs incurred in 2011 under the PSEP, in response to the Commission's directive to PG&E to include a shareholder cost sharing proposal. This amount was estimated at the time the PSEP was filed to be approximately $220 million, but actual costs in 2011 were more than $100 million higher than forecasted. Second, PG&E is not seeking cost recovery for any work that must be undertaken to comply with preexisting regulatory requirements, which means that PG&E shareholders will likely fund approximately

$139.5 million to $155.5 million in PSEP costs to be incurred in the 2011 to 2014 period. In sum, PG&E's shareholders will likely absorb more than $450 million during Phase 1 of the PSEP.

PG&E's customer/shareholder cost allocation is fair and equitable, and results in just and reasonable rates. Under PG&E's proposal, a typical residential customer using 37 therms per month will see a modest average monthly bill increase of $1.85 in 2012, $1.64 in 2013, and $2.21 in 2014. There is no question that the Commission is now requiring all California gas transmission operators to perform additional safety upgrades that have never before been required by federal or state regulations, such as strength testing pre-1961 pipelines, installing automated shut-off valves, and validating the MAOP of gas transmission pipelines by reference to records that are traceable, verifiable, and complete. It is appropriate that customers should pay the costs to implement the significant new safety regulations promulgated by the Commission.

II. PG&E'S PIPELINE MODERNIZATION PROGRAM SHOULD BE APPROVED

The Commission should approve PG&E's Pipeline Modernization Program ("Pipeline Program"), which complies with Decision 11-06-017 by: (1) pressure testing or replacing all in-service natural gas transmission pipelines in California that do not have traceable, verifiable, and complete records of a pressure test in accordance with applicable requirements; (2) setting forth criteria on which pipeline segments are identified for replacement instead of pressure testing; (3) providing a priority-ranked schedule for pressure testing and replacement of pipe not previously pressure tested; and (4) retrofitting pipelines to allow for In-Line Inspection ("ILI") tools.[1]

Phase 1 of the Pipeline Program, which began in 2011, focuses on the highest priority pipelines first—those operating within urban areas (Class 2, 3, 4 and Class 1 HCAs) without a documented pressure test.[2] Phase 2 will begin in 2015, and will focus on completing the rest of

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[1] Exhibit ("Ex.") 2, PG&E Direct, p. 3-1, line 23–p. 3-2, line 4.

[2] Ex. 2, PG&E Direct, p. 3-4, lines 8-13.

the work, primarily on non-strength-tested rural pipelines, urban non-strength-tested pipelines operating below 30 percent SMYS, and all previously tested pipelines that were not tested to the requirements applicable at the time (General Order ("GO") 112 for pipelines installed between 1961 and 1970, and 49 Code of Federal Regulations ("CFR") Subpart J for pipelines installed after 1970).[3]

The Commission should approve PG&E's Pipeline Modernization decision trees and adopt PG&E's cost forecasts for Phase 1. As Jacobs Consultancy concluded based on a thorough review of the PSEP, "PG&E has developed a prioritization and scheduling process that is flexible and addresses the safety aspects of the program, while attempting to reduce the disruption of gas supply to the customer."[4]

A. The Pipeline Modernization Decision Trees Are Based On Sound Engineering Judgment

PG&E's plan uses a deterministic model (i.e., "if this—then this") to identify and phase pipe segments for strength testing or replacement, if they have not been previously tested in accordance with standards applicable at the time of pipe installation.[5] The purpose of this approach is to appropriately schedule work based on the probability of failure for each pipe segment.[6] This methodology was developed by PG&E engineers to address the greatest threats to older pipelines, in consultation with a leading industry expert, whose report is attached as Exhibit 3C to PG&E's August 26, 2011 testimony.[7] The model includes three decision trees, one for each of the following threats: (1) manufacturing-related threats; (2) fabrication and construction-related threats; (3) corrosion and latent third-party and mechanical damage threats.[8] Within each threat, additional decision criteria were added, such as verifiable strength testing

[3] Ex. 1, PG&E's Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, p. 8.

[4] December 23, 2011 "Assessment of Pacific Gas and Electric Company's Pipeline Safety Enhancement Plan," p. 9.

[5] Ex. 2, PG&E Direct, p. 3-3, lines 4-6.

[6] Ex. 1, PG&E's Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, p. 8.

[7] Ex. 1, PG&E's Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, pp. 8-9.

[8] Ex. 2, PG&E Direct, pp. 3-9–3-17.

records, SMYS at maximum operating pressure ("MOP"), and class location or HCA, to refine appropriate actions for each pipe segment.[9]

Every gas transmission pipe segment has been analyzed with the Decision Trees to determine a recommended action based upon the characteristics of the pipe. Each action is denoted by an "Action Box." Actions are prioritized as either Phase 1 or Phase 2.[10] PG&E's proposed threat model and decision criteria methodology—discussed further below—should be adopted by the Commission as an efficient and sound means to prioritize work such that all previously untested pipelines can be either tested or replaced in an orderly manner, as soon as practicable.

1. PG&E's Manufacturing Threats Decision Tree Should Be Approved

PG&E's Manufacturing Threats Decision Tree—depicted in Figure 1 below—should be approved by the Commission as a way to prioritize pipeline segments with a threat from the methods used to manufacture the pipe for testing or replacement. Pipe vintage, long seam type, and proof of a past strength test are important considerations in this determination. The stress level at which each segment operates (SMYS at MOP), and its proximity to people are used to decide whether strength testing or pipe replacement is the appropriate mitigation measure.[11]

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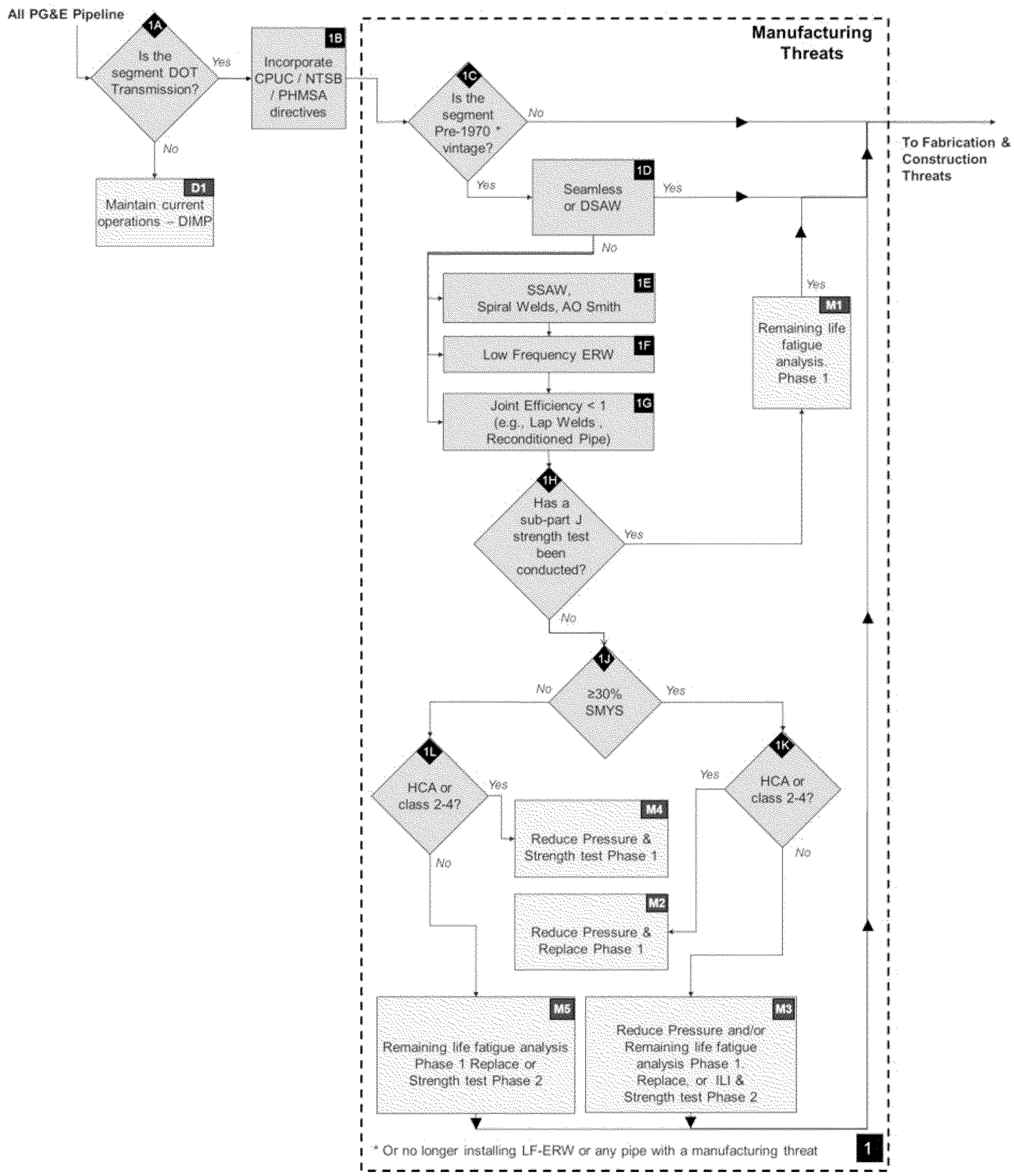
[9] Ex. 1, PG&E's Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, p. 9.

[10] Ex. 1, PG&E's Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, pp. 9-10.

[11] Ex. 1, PG&E's Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, p. 10.

FIGURE 1
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
MANUFACTURING THREAT DECISION TREE



The Division of Ratepayer Advocates ("DRA") submitted an alternate Manufacturing Threats decision tree that removes pipeline replacement as a default Phase 1 action for

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addressing manufacturing threats.[12] Instead, DRA recommends that manufacturing threats be addressed by a hydrotest.[13] The Commission should not adopt DRA's alternate decision tree. Pipeline segments with the long-seam types listed in the Manufacturing Threats Decision Tree are good candidates for replacement because: (1) these segments are susceptible to a higher probability of long-seam failure and less likely to pass a strength test than those not queried for replacement; (2) should these segments pass a hydrostatic test, their longitudinal joint efficiency factor is often the limiting variable in a pipeline that could otherwise be run at a higher pressure, allowing for a longer service life before a capacity upgrade is required; and (3) many of these pipeline segments have been in service for over 50 years.[14] In order for a pipe segment to terminate in Box M2, it must have been manufactured before 1970, which would mean that it was either subject to single-submerged arc welding ("SSAW"), or low frequency electric resistance welding ("ERW"), or some other archaic manufacturing techniques with a joint efficiency factor less than one.[15] Based upon these factors, PG&E believes these pipeline segments are good candidates for replacement.

2. The Commission Should Approve PG&E's Fabrication And Construction Threats Decision Tree

PG&E's Fabrication and Construction Threats Decision Tree — depicted in Figure 2 below — should be adopted as a means for the orderly replacement or testing of pipeline segments with fabrication and construction threats, particularly pipe joining methods and fittings. Pipe vintage, girth weld design and method, and proof of a past strength test are important considerations. As with manufacturing issues, the appropriate mitigation measure will depend on the stress level at which the segment operates, and its proximity to people.

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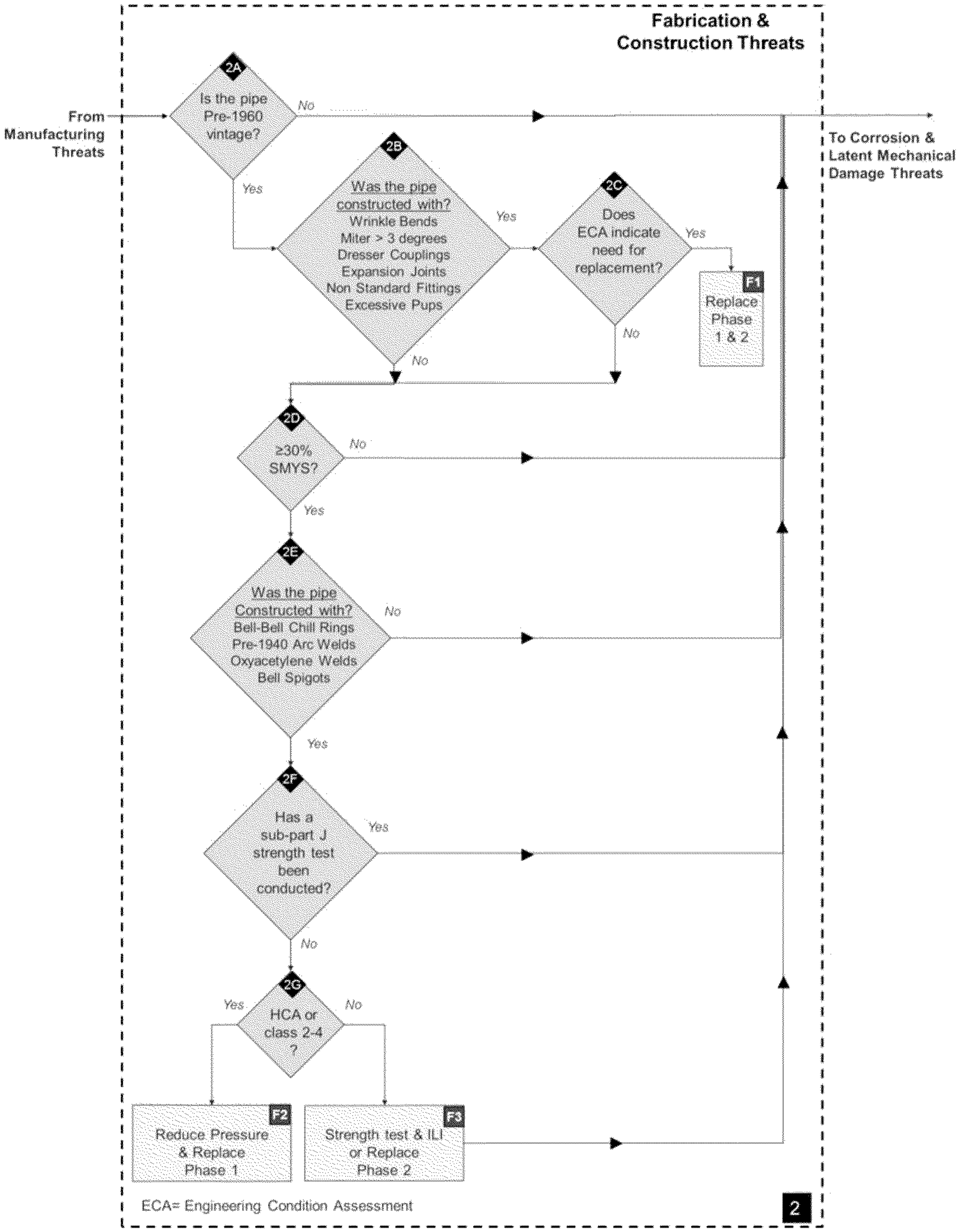
[12] Ex. 145, DRA Direct (Rondinone), p. 11.

[13] Ex. 145, DRA Direct (Rondinone), p. 11.

[14] Ex. 21, PG&E Rebuttal, p. 3-3, line 21—p.3-4, line 11.

[15] Transcript ("Tr.") (Hogenson), p. 1512, line 11—p. 1513, line 6.

FIGURE 2
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
FABRICATION & CONSTRUCTION THREAT DECISION TREE



DRA and The Utility Reform Network ("TURN") recommend removing the Subpart J query at Box 2F, claiming that a hydrostatic test is not well-suited for evaluating the features of the Fabrication and Construction Threats Decision Tree.[16] PG&E included the Subpart J query at Box 2F as a screening tool to ensure that mitigation (whether strength testing or replacement) occurred on untested pipelines within urban areas first, in compliance with the Commission's mandate to strength test or replace previously untested pipelines.[17] If the Subpart J query at Box 2F were removed, the outcome would be to re-test or replace many segments that have already been strength tested, resulting in an inefficient use of resources.[18] As the Commission indicated in Decision 11-06-017, a higher priority use of resources is to execute work on non-tested pipe segments. The presence of a Subpart J query at Box 2F provides this important screening tool.

3. PG&E's Corrosion And Latent Mechanical Damage Decision Tree Should Be Adopted

PG&E's Corrosion and Latent Mechanical Damage Threats Decision Tree—depicted in Figure 3 below—should be approved.

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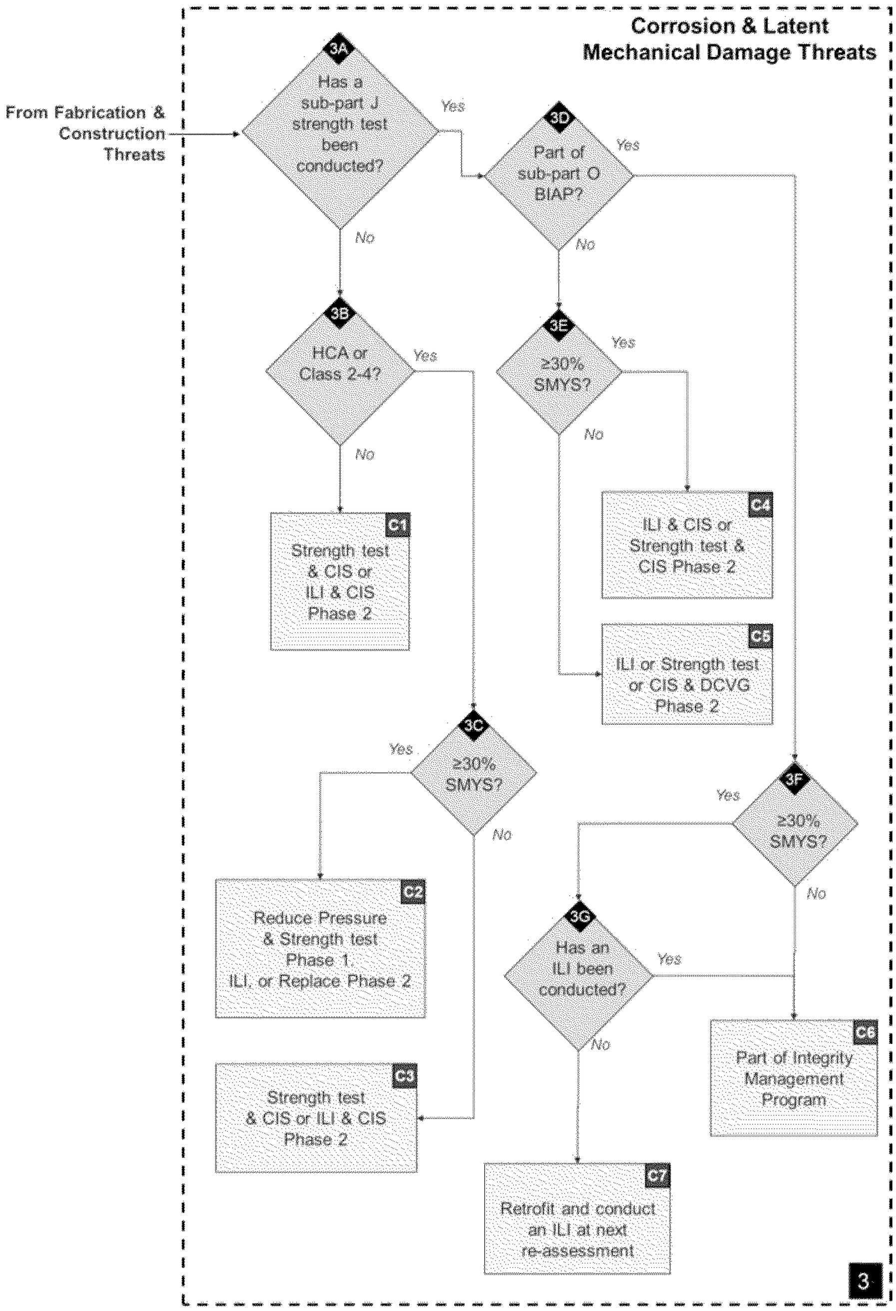
[16] Ex. 145, DRA Direct (Rondinone), p.1-2; Ex. 144, DRA Direct (Roberts), p. 34; Ex. 131, TURN Direct (Kuprewicz), pp. 21-23.

[17] Ex. 21, PG&E Rebuttal, p. 3-7, lines 12-14.

[18] Ex. 21, PG&E Rebuttal, p. 3-7, lines 14-17.

FIGURE 3
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
CORROSION & LATENT MECHANICAL DAMAGE THREAT DECISION TREE



TURN proposes a modified Corrosion and Latent Mechanical Damage Threats Decision Tree. In particular, TURN recommends Close Interval Survey and Phase 2 ILI or Direct Assessment, but not hydrotesting, for untested Class 1 and 2 pipeline segments operating above

30 percent SMYS.[19] For all untested pipeline segments operating below 30 percent SMYS regardless of class location, TURN recommends leak survey and right-of-way ("ROW") monitoring, not pressure testing.[20]

TURN's proposed Decision Tree is not compliant with the Commission's mandate to pressure test or replace previously untested pipeline segments; nor would its recommendations incrementally increase pipeline safety. PG&E already performs leak surveys and ROW monitoring as part of its pipeline maintenance, and has proposed as part of PSEP to increase the frequency of leak surveys on untested pipeline segments within urban areas until they are pressure tested or replaced.[21] TURN's recommendation would result in no action on some untested pipeline segments. Close interval surveys, leak surveys, and ROW monitoring are not appropriate substitutes for pipeline strength testing or replacement, and will not result in commensurate assurances of pipeline safety.[22] TURN's alternate Construction and Fabrication Threats Decision Tree is focused on program cost reductions, not safety, and should be rejected.

B. PG&E's Proposed Phase 1 Scope Enhances Safety And Should Be Adopted

The Decision Trees provide the foundation for prioritizing the Pipeline Modernization Plan into two phases. Phase 1 consists of pipe segments within urban areas (*i.e.* Class 2, 3, and 4 and Class 1 HCA) that have not been previously strength tested (or for which records of a strength test cannot be verified). Individual projects are then scheduled to ensure the pipe segments with the highest priority and public safety exposure are completed early in the program. Project prioritization criteria used include class location, Potential Impact Radius ("PIR") and inclusion in an HCA.[23] PG&E's project prioritization model will serve as the basis for developing an annual project schedule, but the sequence of project completion will change

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[19] Ex. 131, TURN Direct (Kuprewicz), p. 25, Figure 4; Ex. 21, PG&E Rebuttal, p. 3-8, lines 24-26.

[20] Ex. 131, TURN Direct (Kuprewicz), p. 25, Figure 4; Ex. 21, PG&E Rebuttal, p. 3-8, lines 27-29.

[21] Ex. 2, PG&E Direct, Chapter 6, Section D; Ex. 21, PG&E Rebuttal, p. 3-9, lines 1-5.

[22] Ex. 21, PG&E Rebuttal, p. 3-9, lines 7-10.

[23] Ex. 2, PG&E Direct, p. 3-33, line 17—p. 3-34, line 8.

based on other factors such as public safety, project routing, permitting, environmental considerations, efforts to schedule work to minimize service interruptions to customers, scheduling integration with other planned work and third party utilities, weather, geographic location, and efficient use and mobilization of resources.[24]

As a result of PG&E's Pipeline Modernization Decision Trees, coupled with PG&E's engineering judgment, PG&E recommends the following scope of work in Phase 1:

Strength Testing: Strength testing is the chosen assessment method for 546 miles of pipe segments in Phase 1 under the Decision Trees.[25] To strength test the 546 miles of pipe segments, PG&E plans to strength test about 783 miles of pipe segments in Phase 1.[26] This 237 mile difference resulted from determination of efficient ending points per project, as opposed to the exact start and stop of every pipe segment without a pressure test.[27] The tests will be conducted in accordance with 49 CFR, Subpart J requirements.

Pipeline Replacement: PG&E estimates that it will replace 186 miles of pipeline during Phase 1 of the Pipeline Modernization Program.[28] PG&E has opted to replace many of its older vintages of pipe because these pipelines are more likely to contain manufacturing, fabrication, and construction flaws.[29] During Phase 1, PG&E plans on replacing the following types of pipe:

- Pipe manufactured by processes generally thought to be susceptible to producing seam weld anomalies or weld seams with poor fracture toughness, including pre-1970, low-frequency ERW, flash welded, SSAW, furnace butt welded, lap welded, and hammer welded pipe.

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[24] Ex. 2, PG&E Direct, p. 3-34, line 6—p. 3-35, line 17.

[25] Ex. 2, PG&E Direct, p. 3-29, lines 23-24.

[26] Ex. 2, PG&E Direct, p. 3-29, lines 26-28.

[27] Ex. 2, PG&E Direct, p. 3-29, line 28—p. 3-30, line 3.

[28] Ex. 2, PG&E Direct, p. 3-22, lines 28-29.

[29] Ex. 2, PG&E Direct, p. 3-22, lines 29-32.

- Pipelines constructed with welding techniques generally thought to produce low toughness or inferior designed girth welds, such as oxygen-acetylene welds, bell-bell chill ring welds, bell and spigot welds, and pre-1940 arc welds.[30]

In-Line Inspection: PG&E proposes to retrofit all pipelines operating at or above 30 percent SMYS, and many below 30 percent SMYS, to accommodate inspections using current intelligent "pigging" technologies.[31] Phase 1 includes 199 miles of pipeline retrofit work for ILI and 234 miles of actual in-line inspections (or "ILI runs").[32] These ILI pipeline segments are located on the L-300 backbone system and on three urban pipelines located within the South Bay and San Francisco Peninsula.[33]

The scope of Phase 1 is aggressive. PG&E requests that the Commission adopt PG&E's proposal that the scope of Phase 1 include previously untested pipe segments in Class 2, 3, and 4 and Class 1 HCAs, and that the Commission reject other parties' proposals to reduce scope.

1. DRA's Proposal To Reduce Scope Should Not Be Adopted

DRA hired a consultant–Berkeley Engineering and Research ("BEAR")–to create modified decision trees, and compared the results of BEAR's analysis to the work proposed by PG&E. The results are compared in Table 4 (page 35) of Exhibit 144. DRA's proposed scope of work for Phase 1 of the PSEP is drastically reduced from PG&E's proposal, elevates cost reductions over safety, and should be rejected.

For example, PG&E recommends hydrotesting 783 miles of gas transmission pipeline in Phase 1.[34] DRA recommends that PG&E hydrotest only 472 miles of transmission pipeline in Phase 1, roughly 60 percent of PG&E's request.[35] DRA's scope reduction is not consistent with

[30] Ex. 2, PG&E Direct, p. 3-23, lines 10-20. TURN witness Kuprewicz conceded that these types of vintage pipe are inferior to modern pipe, and carry a significantly higher risk of failure than modern pipe. Tr. (Kuprewicz), p. 2217, line 13—p. 2218, line 3.

[31] Ex. 2, PG&E Direct, p. 3-26, lines 7-11.

[32] Ex. 2, PG&E Direct, p. 3-26, lines 17-18.

[33] Ex. 2, PG&E Direct, p. 3-26, lines 18-20.

[34] Ex. 21, PG&E Rebuttal, p. 3-18, lines 29-30.

[35] Ex. 144, DRA Direct (Roberts), p. 40, Table 5.

the Commission's mandate to strength test or replace previously untested pipelines *as soon as practicable*. PG&E estimates that at least 2,000 segment miles of gas transmission pipe will require strength testing or replacement in Phase 1 or Phase 2 of the PSEP.[36] Assuming the Commission were to adopt DRA's proposed strength testing rate of 472 miles over a four year period, it would take 17 years to test 2,000 miles of untested pipe.[37] Assuming a twenty percent segment re-test rate, DRA's compliance plan would take 20 years to complete.[38] In addition, DRA did not consider project engineering principles (such as gaps of non-Phase 1 pipe between Phase 1 segments, or segments ending in the middle of roadways, waterways or other inaccessible locations) that result in longer strength tests than required by segment data alone.[39]

DRA's proposed reductions to pipeline replacement fare no better. PG&E recommends replacing 186 miles of gas transmission pipe in Phase 1. DRA's proposal would reduce this number by 39 percent, to 113 miles of gas transmission pipe replaced in Phase 1.[40] DRA's proposed reductions would adversely impact the margin of safety on PG&E's pipelines.[41] In addition, it does not appear that DRA considered whether its proposed scope reductions would have any impact on PG&E's ability to pig its pipelines going forward.[42] In fact, DRA's proposed reduction in pipeline replacement would negatively impact miles of pipe made piggable, as compared to PG&E's proposal.[43]

The following examples illustrate the faulty analysis that underlies DRA's proposed scope reductions. On Line 108, DRA removed pipeline segments from proposed replacement, asserting that the PG&E decision trees do not indicate replacement for these segments.[44] DRA

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[36] Ex. 21, PG&E Rebuttal, p. 3-19, lines 7-9.

[37] Ex. 21, PG&E Rebuttal, p. 3-19, lines 12-14.

[38] Ex. 21, PG&E Rebuttal, p. 3-19, lines 14-16.

[39] Ex. 21, PG&E Rebuttal, p. 3-18, line 30—3-19, line 2.

[40] Ex. 21, PG&E Rebuttal, p. 3-20, lines 7-12.

[41] Ex. 21, PG&E Rebuttal, p. 3-20, lines 15-31.

[42] Ex. 21, PG&E Rebuttal, p. 3-21, lines 13-17.

[43] Ex. 21, PG&E Rebuttal, p. 3-21, lines 17-19.

[44] Ex. 147, DRA Direct (Scholz), pp. 26-27, Table 22.

also proposed not to replace short pipeline segments of Line 108 that are located between pipeline segments slated for replacement.[45] DRA's proposed modifications to project scope on Line 108 cannot be justified by sound engineering principles. First, Line 108 is currently constructed of 16-inch, 20-inch, and 24-inch pipe. Most of the 16-inch pipe was installed in 1930 with flash-welded long seam, miter bends, bell-bell chill ring joints, and expansion joints, all of which make Line 108 extremely difficult to ILI.[46] PG&E has proposed to replace 16-inch pipe with 24-inch pipe, because current ILI tools can handle the differential between 20-inch and 24-inch pipe (but cannot handle the differential between 16-inch and 24-inch pipe).[47] If PG&E were to elect not to replace pipeline segments located in between segments slated for replacement, that would prevent PG&E from running ILI tools through Line 108 in the future.

Second, excluding such short pipeline segments from replacement (some only 5 feet long) does not make sense from an engineering or cost/benefit perspective. The added cost for excavation around pressurized pipelines, bell hole excavation and shoring at the segment end points, additional fittings and elbows for the additional offsets that would need to be created in order to retain this pipe, additional construction welding, pipeline elevation changes, pipeline cleaning, external recoating, and increased pipeline clearance outage duration to reuse and connect these pipe segments, would far exceed any cost savings from not replacing these short segments.[48]

Other examples of DRA's flawed project analysis can be found on pages 3-24 through 3-34 of Exhibit 21, PG&E's Rebuttal Testimony.

2. PG&E Appropriately Included All Class 2 Pipelines In Phase 1

DRA, TURN, and the City and County of San Francisco ("CCSF") claim that not all

[45] Ex. 147, DRA Direct (Scholz), p. 26; Ex. 21, PG&E Rebuttal, p. 3-26, lines 17-24.

[46] Ex. 21, PG&E Rebuttal, p. 3-25, line 23—p. 3-26, line 3.

[47] Ex. 21, PG&E Rebuttal, p. 3-26, lines 3-9.

[48] Ex. 21, PG&E Rebuttal, p. 3-26, line 28 —p. 3-27, line 2.

Class 2 areas should be treated with equally high priority as HCA or Class 3 or 4 areas.[49] PG&E took a more holistic approach to Phase 1 of the PSEP. When PG&E developed the Phase 1 projects to replace or test untested pipelines, it looked beyond the pure decision tree query results and considered adjacent pipeline segments as well, in order to develop projects that would enhance safety, enhance project and program efficiency, increase pipeline piggability, reduce overall community impact from construction, and result in long-term cost savings.[50] There are considerable up-front project costs (engineering, design, permitting, site access, temporary construction easements, outage clearances, customer and community coordination) on every project.[51] While several parties make proposals that would most likely reduce costs in the short-term, this strategy will require more years to complete and result in greater overall program costs, because PG&E will have to go back and either pressure test or replace Class 2 and Class 1 adjoining pipe segments at a later time.[52] This is not a sound strategy to meet the Commission's mandate to test or replace all previously untested pipeline segments in a timely and cost-effective manner.

In addition, CCSF criticizes PG&E for prioritizing Class 2 segments operating above 30 percent SMYS over Class 3 segments operating between 20 and 30 percent SMYS.[53] However, untested Class 2 pipeline segments operating above 30 percent SMYS have a greater probability of an uncontrolled rupture and public safety risk than untested Class 3 pipeline segments operating below 30 percent SMYS.[54] As even non-PG&E intervenors have recognized, pipeline failures are more likely to result in a rupture than a leak when they occur on pipelines operating above 30 percent SMYS, while pipelines operating below 30 percent SMYS will typically fail as

[49] Ex. 145, DRA Direct (Rondinone), pp. 8-10; Ex. 131, TURN Direct (Kuprewicz), pp. 3, 18, 19; Ex. 137, CCSF Direct (Gawronski), p. 7.

[50] Ex. 21, PG&E Rebuttal, p. 3-15, lines 15-19; p. 3-16, lines 2-6.

[51] Ex. 21, PG&E Rebuttal, p. 3-16, lines 8-11.

[52] Ex. 21, PG&E Rebuttal, p. 3-16, lines 14-19.

[53] Ex. 137, CCSF Direct (Gawronski), p. 7, lines 2-7.

[54] Ex. 21, PG&E Rebuttal, p. 3-16, lines 28-32.

a leak before rupture.[55] Therefore, work on Class 2 pipelines operating above 30 percent SMYS should proceed ahead of work on Class 3 pipelines operating below 30 percent SMYS because the risk of a failure resulting in a pipeline rupture is greater for pipelines operating above 30 percent SMYS.[56] A pipeline rupture would have a greater impact on surrounding communities than a leak.

3. PG&E's Proposed Diameter Increases Are Warranted

Of the 149 specific pipeline replacement projects proposed as part of Phase 1, 36 projects include proposed pipeline segment replacements with larger diameter pipe, and 12 projects include proposed pipeline segment replacements with smaller diameter pipe.[57] There are a number of reasons for pipeline diameter changes, including the following:

(1) To meet typical pipeline manufacturing standards (*e.g.* installing 24-inch standard versus 22-inch non-standard pipe).

(2) To increase pipeline piggability. Industry ILI tools designed to detect long-seam defects are not capable of working with multi-diameter pipelines. PG&E has proposed increasing pipeline diameter on many of the pipeline segments slated for replacement in order to address the Commission's mandate that gas pipeline operators must consider retrofitting pipeline to allow for in-line inspection tools.

(3) To increase capacity. If downstream customer demands are at or near the current pipeline capacity, it is more efficient and less disruptive to the community and property owners to install one larger diameter pipeline now, versus installing the same diameter pipe now and paralleling the new pipeline at a future date.[58]

In order to determine if a pipeline diameter change is warranted to enhance piggability, the pipeline operator has to look at the diameters both upstream and downstream of the proposed

[55] Ex. 21, PG&E Rebuttal, p. 3-16, line 32—p. 3-17, line 2.

[56] Tr. (Hogenson), p. 1451, lines 14-21; p. 1452, lines 10-22.

[57] Ex. 21, PG&E Rebuttal, p. 3-23, lines 21-24.

[58] Ex. 21, PG&E Rebuttal, p. 3-23, lines 1-20.

pipeline replacement.[59] PG&E witness Mr. Hogenson used Line 109 as an example in response to questions posed by Sunil Shori of the Commission's CPSD:

> Today Line 109 has 30-inch diameter pipe, 24-inch diameter pipe, and 22-inch diameter pipe. If we replace the 1938 22-inch diameter pipe with 24, that makes that pipeline essentially piggable, meaning there are tools out there today that can pig between 24 and 30. There's not an ILI tool on the market today that can go from 20 inch to 30 inch. They just can't do that.[60]

PG&E's principal reason for replacing roughly 57 miles of pipeline with larger diameter pipe was to "improve pipeline piggability."[61] The fact that these diameter increases also result in capacity increases is incidental, and is not a good reason to reject the proposed diameter changes.[62]

C. PG&E's Plan Addresses Concerns About Data Accuracy

The Pipeline Program used the Gas Transmission Geographic Information System ("GIS") for its source data. The GIS is a two-dimensional mapping tool that places an asset, such as a pipeline segment or valve, onto an electronic map with Global Positioning System coordinates for geographic referencing.[63] PG&E's GIS contains records on approximately 6,700 miles of transmission and distribution gas pipeline, subdivided into over 36,600 individual pipe segments based on changes in physical attributes, characteristics, and environment.[64] PG&E used a snapshot of the GIS database taken in January 2011. The GIS database was the best and most readily available information source PG&E had at the time of the filing.[65]

Several parties have raised concerns about the accuracy of the data in PG&E's GIS database. In particular, parties claim that information from the MAOP Validation Project and

[59] Tr. (Hogenson), p. 1379, line 28—p. 1380, line 7.

[60] Tr. (Hogenson), p. 1426, lines 12-20.

[61] Tr. (Hogenson), p. 1598, line 23—p. 1599, line 11.

[62] Tr. (Hogenson), p. 1604, line 22—p. 1605, line 9.

[63] Ex. 2, PG&E Direct, p. 3-18, lines 31-34.

[64] Ex. 2, PG&E Direct, p. 3-19, lines 3-6.

[65] Ex. 21, PG&E Rebuttal, p. 3-10, lines 7-9.

Class Location studies has not yet been incorporated into GIS. Although it is correct that information from those efforts has not been incorporated wholesale into GIS, PG&E will mitigate any inaccuracies in the GIS database during the preliminary project engineering phase for each project in the PSEP. This data validation will ensure that GIS pipeline attributes are verified, that blank and assumed values are researched, and that updated data are uploaded into the PSEP database.[66] PG&E project engineers will cross-reference Pipeline Features Lists developed as part of MAOP Validation, construction as-built packages, and other documentation to confirm or modify the project scope for each project prior to the start of project design engineering.[67] Once the pipe segment data validation is complete, those pipeline segments will be processed through the decision tree logic to verify that PG&E is taking the appropriate safety action.[68] This is a critical step in the Pipeline Modernization Program where PSEP project scopes may be redefined.[69]

Concerns about the accuracy of data in GIS are being addressed on a project-by-project basis, and should not be used as a reason to delay the important safety work under the PSEP. Variances from the work as forecasted in August, 2011 will be shared with the Commission at regular intervals, if PG&E's proposed reporting procedure is adopted.

D. PG&E's Strength Testing Program Comports With Applicable Regulations And Sound Engineering Principles

TURN levels several criticisms of PG&E's strength testing program. Most of the criticisms of PG&E's strength test program proffered by TURN, however, stem from the fact that TURN's witness Kuprewicz does not believe that federal requirements are adequate. As TURN's witness testified, "I think [Subpart J] is incomplete, and it's well known, and I've testified to that in various other things, and we need to work on it in the federal." [70] This

[66] Ex. 21, PG&E Rebuttal, p. 3-10, lines 9-14.

[67] Ex. 21, PG&E Rebuttal, p. 3-11, lines 29-32.

[68] Ex. 21, PG&E Rebuttal, p. 3-10, lines 14-16.

[69] Ex. 21, PG&E Rebuttal, p. 3-10, lines 16-17; Tr. (Hogenson), p. 1449, lines 8-23.

[70] Tr. (Kuprewicz), p. 2203, lines 22-25.

testimony is contradicted by an industry-leading expert, who testified that the strength test requirements in federal regulations are adequate to detect pipe flaws.[71] Any issues TURN's witness has with federal regulations should be addressed on an industry-wide level through revisions to federal regulations, not on a utility-by-utility basis.

One example of this conflict is TURN's argument that all hydrotests set a minimum pressure test parameter of 90 percent SMYS. As TURN's witnesses recognizes, federal regulations do not establish minimum SMYS levels for a hydrotest.[72] Moreover, as a leading technical expert in the pipeline industry testified, there are several reasons why it may not be prudent to test a pipeline to 90 percent SMYS, including:

- Not all diameters and vintages of pipe were tested at the pipe mill to 90 percent SMYS. Testing low-frequency ERW pipe beyond the mill test pressure could damage seam flaws that would not otherwise pose a threat to the integrity of the pipe at the operating pressure.
- The pressure necessary to achieve 90 percent SMYS, particularly in smaller diameter pipe, may be many times the MAOP. There is usually little benefit to testing more than two or three times the MAOP.
- The pressure necessary to achieve 90 percent SMYS may exceed the rated capability of components such as flanges or valves which in most cases are not intended to be tested to room temperature rated working pressures.[73]

Moreover, it is simply not practical to strength test *in-situ* pipelines to 90 percent SMYS. Some of PG&E's hydrotests in 2011 had as many as 10 different types of pipe with various wall thicknesses and SMYS in a single test. When testing the pipeline to 1.5 times the MAOP, the test pressure achieved will occur at varying SMYS levels depending on that pipe segment's

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[71] Ex. 21, PG&E Rebuttal, p. 5-1, line 18—p. 5-2, line 2.

[72] Tr. (Kuprewicz), p. 2208, lines 2-5; see also Tr. (Campbell), p. 1861, lines 22-26.

[73] Ex. 21, PG&E Rebuttal, p. 5-2, line 28—p. 5-3, line 10.

characteristics.[74] Achieving 90 percent SMYS in all segments could mean that one of the pipe's segments may be stressed to well over 100 percent SMYS, which could potentially damage the pipe.[75] In addition, it would be cost prohibitive for any pipeline operator to cut each differing segment and hydrotest it separately to achieve 90 percent SMYS for every segment.[76] Likewise, segmenting the pipe to shorten elevation differences to allow for higher testing would significantly add to the costs of the hydrotesting program.[77]

PG&E's strength testing program complies with all applicable regulations, and should not be altered simply because one witness does not believe that federal regulations are adequate.

E. Pipeline Modernization Cost Forecasts Are Reasonable And Should Be Adopted

PG&E requests that the Commission adopt PG&E's forecast of $928.1 million in capital, and $407.7 in expense for Pipeline Program work within the scope of Phase 1 for 2011 through 2014.[78] PG&E's specific forecasts for pipeline replacement and strength testing are discussed in further detail below.

1. The Commission Should Approve The Pipeline Replacement Cost Forecasts

PG&E requests that the Commission adopt its cost forecast of $834.2 million for Phase 1 pipeline replacements as a reasonable estimate of costs.[79] In order to develop cost estimates for the pipe replacement work to be performed as part of Phase 1, PG&E hired Gulf Interstate Engineering ("Gulf") to prepare individual project work scopes and cost estimates.[80] PG&E has significant experience constructing pipelines in northern California. Gulf relied on PG&E's

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[74] Ex. 21, PG&E Rebuttal, p. 4-10, lines 18-23.

[75] Ex. 21, PG&E Rebuttal, p. 4-10, lines 23-26.

[76] Ex. 21, PG&E Rebuttal p. 4-10, line 26—p. 4-11, line 2.

[77] Ex. 21, PG&E Rebuttal, p. 4-9, line 17—p. 4-10, line 4.

[78] Ex. 2, PG&E Direct, p. 3-6, Table 3-1.

[79] Ex. 2, PG&E Direct, p. 3-63, Table 3-3.

[80] Ex. 2, PG&E Direct, p. 3-39, lines 6-8.

historic pipeline construction costs when developing its cost estimates.[81] For pipeline replacement cost estimates, a set of nominal "one mile" cost models was developed based on project type, pipeline diameter, and the level of congestion in the area (*e.g.* non-congested, semi-congested, and highly congested).[82] Those "one mile" cost models were then used to calculate a cost per foot of pipeline replaced.[83] The resulting unit costs were then reviewed and validated with a California-based gas transmission and distribution pipeline contractor.[84] The pipe replacement project unit costs forecasted for Phase 1 vary from a low of $780 per foot to a high of $981 per foot, with an average unit cost of $855 per foot.[85]

DRA witness Sibylle Scholz—a forensic economist with no engineering degree[86] and no experience examining costs for natural gas pipeline projects[87]—claims that PG&E's pipeline replacement cost estimates are higher than industry averages. The two studies Ms. Scholz relies upon are inapposite here. The first study was performed for the University of California, Davis and reports cost projections from 20,000 miles of interstate natural gas, oil, and petroleum product pipelines in 893 proposed projects in the United States over a 13-year period from 1991-2003 for the purpose of estimating the costs of a future hydrogen pipeline system. The data reported in this study have little bearing on PG&E's pipeline replacement costs, for several reasons. First, the data show cost "projections," not actual gas transmission pipeline construction costs.[88] Second, this study looked at cost projections for interstate pipelines traversing primarily rural areas.[89] The UC Davis study explicitly notes that it did not consider whether costs

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[81] Ex. 21, PG&E Rebuttal, p. 3-36, lines 6-10.

[82] Ex. 2, PG&E Direct, p. 3-40, lines 9-13.

[83] Ex. 2, PG&E Direct, p. 3-40, lines 14-16.

[84] Ex. 21, PG&E Rebuttal, p. 3-36, lines 10-12.

[85] Ex. 2, PG&E Direct, p. 3-40, lines 18-20.

[86] Ex. 153, Statement of Qualification of Sibylle Scholz.

[87] Ex. 140, DRA's response to PGE_DRA_008-07.

[88] Ex. 138, DRA's response to PGE_DRA_005-Q1, p. 1 of UC Davis study; Ex. 21, PG&E Rebuttal, p. 3-37, lines 14-16.

[89] Ex. 138, DRA's response to PGE_DRA_005-Q1, UC Davis study "Summary."

increased in urban areas, deferring this question to "further research."[90] Third, it is unclear from the study if any of the included projects were natural gas pipelines in California.

The second article describes the development of a methodology and equations by Pacific Northwest National Laboratory for conceptual cost estimating of onshore pipelines using Oil & Gas Journal data.[91] These data have some of the same infirmities as the UC Davis study. This study relies upon cost estimates provided to the Federal Energy Regulatory Commission, which has jurisdiction over interstate natural gas transmission pipelines.[92] Over a 30-year period, data were collected for 2,000 pipeline projects. The average project length for the eight on-shore projects reported from July 1, 2009 through June 30, 2010, was 65.5 miles. For the previous 12-month period, the average length of the pipeline project was 104 miles.[93] In comparison, the average PSEP pipeline replacement project length is 1.1 miles.[94] These cost projections for long interstate pipelines are not applicable to the type of targeted pipeline replacement that PG&E has planned under the PSEP.

Relying on industry cost projections for interstate pipelines in primarily rural areas, instead of actual historical costs incurred by PG&E to construct pipelines in California, does not make sense. Over the past 20 years, PG&E has constructed approximately 940 miles of gas transmission pipeline.[95] PG&E's historic costs were provided to Gulf, and formed the basis for PSEP pipeline replacement cost projections.[96]

DRA witness Delfino's pipeline replacement cost estimates also are not relevant to the PSEP. As Mr. Delfino explains, the basis for his pipeline replacement costs are non-U.S. off-shore, sub-sea pipelines, which are not representative of pipeline construction in the urban

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[90] Id.

[91] Ex. 147, DRA Direct (Scholz), p. 5, lines 4-5.

[92] Ex. 138, DRA's response to PGE_DRA_005-Q2, p. 1 of "National lab uses OGJ data to develop cost equations."

[93] Ex. 21, PG&E Rebuttal, p. 3-38, lines 2-7.

[94] Ex. 21, PG&E Rebuttal, p. 3-38, lines 7-9.

[95] Ex. 21, PG&E Rebuttal, p. 3-39, lines 9-10.

[96] Tr. (Hogenson), p. 1404, lines 21-28.

locations where PG&E's Phase 1 replacements are located.[97] In fact, Mr. Delfino's estimates do not account for several variables that affect on-shore gas transmission pipelines, such as:

- Permitting: Permitting requirements from federal and state environmental agencies, such as the Bureau of Land Management and U.S. Fish and Wildlife Service, plus city and county discretional permits, can add up to 10 percent or more of a total project cost.
- Land and ROW acquisitions: can add up to 20 percent of a total project cost
- Crop Damages, street and landscape restoration, business disturbance funding, home owner hotel accommodations, etc.
- Excavation shoring and trench plating
- Traffic control
- Slurry and import backfill, 100 percent compaction, and special paving requirements
- Padding under the pipeline to ensure the new pipeline is not damaged from rock dents and coating scratches during installation
- Work hour restrictions
- The price of valves, fittings, pressure control fittings, station components, and other non-pipe materials and labor costs[98]

In short, Mr. Delfino's cost estimates may be adequate to estimate the cost of an off-shore pipeline located outside the United States, but should not be given any weight in this proceeding.

2. PG&E's Strength Testing Cost Forecasts Should Be Adopted

PG&E requests that the Commission adopt its cost forecast of $393.2 million in expense, and $63.6 million in strength test related capital expenditures, for Phase 1 strength testing as a reasonable estimate of costs.[99] PG&E's strength testing cost forecasts are based on a small subset of past PG&E hydrotesting projects on existing pipelines over the last ten years, and on

[97] Ex. 146, DRA Direct (Delfino), p. 1-2; Ex. 21, PG&E Rebuttal, p. 3-39, lines 23-27.

[98] Ex. 21, PG&E Rebuttal, p. 3-39, line 27—p. 3-40, line 27.

[99] Ex. 2, PG&E Direct, p. 3-65, Table 3-5; Ex. 8, p. 3-6, line 176.

unit rate input by a California-based pipeline construction company, supplemented by Gulf's experience.[100] Cost per foot models were developed to account for line pre-cleaning with in-line tools, line filling, testing, cleaning and drying, and an allowance for replacing valve blow down stacks, line branch connections, and other existing line taps.[101] The unit cost for each strength test will vary due to differences in pipe diameter, pipe distance to be tested, and the number of individual tests to be performed.[102] The strength test project unit cost forecast in Phase 1 varies from a low of $47 per foot to a high of $2,646 per foot, with an average unit cost of $95 per foot.[103]

DRA witness Neil Delfino challenges PG&E's hydrotesting cost forecasts on the grounds that they are higher than "industry estimates."[104] Mr. Delfino claims that certain activities included in PG&E's hydrotesting cost estimate should be excluded. For example, he states that, "[p]ipeline cleaning to remove debris and free liquids are maintenance work tasks and should not be included in hydrotesting. Any prudent pipeline operator will do their maintenance pigging on a monthly (if there are variations in the product in the pipeline) or quarterly schedule. At any time the prudent operator's pipeline could be shutdown, drained of product, and hydrotested without having to go through the cleaning process."[105] In fact, regular cleaning of an integrated gas transmission and distribution system would be unusual.[106] PG&E would have to blow down its entire pipeline system and lose service to customers in order to regularly clean its pipelines, at a very high cost.[107] Therefore, pipeline pre-cleaning costs are an appropriate cost to include as part of PG&E's hydrotesting program.[108] Mr. Delfino also did not consider other costs of a

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[100] Ex. 2, PG&E Direct, p. 3-41, lines 10-12.

[101] Ex. 2, PG&E Direct, p. 3-41, lines 12-15.

[102] Ex. 2, PG&E Direct, p. 3-41, lines 31-33.

[103] Ex. 2, PG&E Direct, p. 3-41, line 33—p. 3-42, line 3.

[104] Ex. 146, DRA Direct (Delfino), p. 2-3, lines 9-10.

[105] Ex. 146, DRA Direct (Delfino), p. 2-8, lines 11-16.

[106] Ex. 21, PG&E Rebuttal, p. 4-3, lines 6-8.

[107] Ex. 21, PG&E Rebuttal, p. 4-3, lines 8-16; Tr. (Campbell), p. 1863, line 23—p. 1864, line 11.

[108] Ex. 21, PG&E Rebuttal, p. 4-3, line 20—p. 4-4, line 2.

massive strength testing program on an integrated gas transmission and distribution system, including alternative supplies of gas to customers, managing multiple taps, and customer and local government outreach.[109]

DRA witness Scholz also cites two pieces of industry data—a paper developed by the American Gas Association ("AGA") and comments submitted by the Interstate Natural Gas Association of America ("INGAA") Foundation—to support DRA's claim that PG&E's strength testing estimates are higher than "industry averages."[110] Neither report is relevant here. The AGA study states that, "the costs of pressure testing an in-service transmission pipeline as an integrity management assessment under Subpart O is estimated to range from less than $100,000 to $1,500,000 per mile of main."[111] This is a very broad range of costs, and the report fails to distinguish the diameter size or any other potential cost drivers of the pipelines being tested. In any event, PG&E's strength testing cost estimates fall within this range.[112] Likewise, the testimony of INGAA Foundation's President and CEO, Donald Santa, provides a broad range of cost per mile of $250,000 to $500,000 for strength testing, but provides no details on the pipe diameters, test medium, average test length, or any other cost drivers that can be used to compare the cost of PG&E's testing program to the industry average of interstate pipelines.[113] Other than relying on these industry data and Mr. Delfino's analysis, DRA witness Scholz did not perform any independent analysis of PG&E's cost estimates for strength testing.

In fact, PG&E's actual experience in 2011 shows that PG&E's forecast may have *underestimated* the costs for such a significant hydrotesting program. In 2011, PG&E conducted 97 hydrostatic tests, covering 163.6 miles of gas transmission pipe.[114] The total cost of the

[109] Ex. 21, PG&E Rebuttal, p. 4-4, line 13—p. 4-5, line 24.

[110] Ex. 147, DRA Direct (Scholz), pp. 10-11.

[111] Ex. 138, DRA's response to PGE_DRA_005-Q3, AGA study, p. 13.

[112] Ex. 21, PG&E Rebuttal, p. 4-8, lines 27-31.

[113] Ex. 21, PG&E Rebuttal, p. 4-8, line 31—p. 4-9, line 2.

[114] Ex. 21, PG&E Rebuttal, p. 4-2, lines 1-2.

program in 2011 was $231 million, or $1.412 million per mile.[115] This compares to PG&E's cost forecast of about $850,000 per mile for 30-inch to 42-inch diameter pipe, and $760,000 per mile for 22-inch to 28-inch diameter pipe.[116] This is due, in part, to the fact that PG&E did not anticipate the number of cleaning runs that would be required for many of the 2011 hydrotests.[117] As PG&E's witness on contingency testified, PG&E's base cost estimates for hydrotesting assumed only one cleaning run prior to the actual hydrotest.[118] While PG&E believes that it can drive down strength testing costs in 2012 and beyond through competitive bidding and given longer planning horizons, recent experience indicates no probability that strength testing costs will be lower than estimated in the PSEP filing.[119]

PG&E's strength testing cost estimates were developed based on actual data analyzed by experienced engineers, and should be adopted by the Commission as a reasonable estimate of strength testing costs.

III. PG&E'S VALVE AUTOMATION PROGRAM SHOULD BE APPROVED

Decision 11-06-017 requires pipeline operators in California to consider the installation of automatic or remote controlled shut-off valves.[120] In addition, Section 957 of the California Public Utilities Code requires the installation of automatic shutoff or remote controlled sectionalized block valves on both of the following facilities, if it determines those valves are necessary for the protection of the public: (a) intrastate transmission lines that are located in a high consequence area; and (b) intrastate transmission lines that traverse an active seismic earthquake fault. Section 957(a)(2) of the Public Utilities Code requires operators to provide the Commission with a valve location plan.

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[115] Ex. 21, PG&E Rebuttal, p. 4-2, lines 5-6.

[116] Ex. 21, PG&E Rebuttal, p. 4-2, lines 9-11.

[117] Ex. 21, PG&E Rebuttal, p. 4-4, lines 3-7; Tr. (Campbell), p. 1817, lines 22-28.

[118] Tr. (Caletka), p. 2130, lines 17-27.

[119] Ex. 21, PG&E Rebuttal, p. 4-2, lines 15-23.

[120] D. 11-06-017, Conclusion of Law 9; Ordering Paragraph 8.

PG&E submitted its Valve Automation Program to the Commission for approval on August 26, 2011. The objective of the Valve Automation Program is to help reduce the risk posed by an extended duration natural gas-fueled fire created by a gas pipeline rupture (and work in concert with first responders) by expanding the use of automated gas transmission pipeline system isolation valves ("automated valves"). There are two types of automated valves included in the program: (1) Remote Control Valves ("RCV"); and (2) Automatic Shut-off Valves ("ASV"). RCVs are valves that can be closed via the Supervisory Control and Data Acquisition ("SCADA") system by a remote operator located at a Gas Control Center. ASVs are valves that are closed automatically based upon the local control system at the valve site detecting a line rupture or any other condition for which the controls are programmed to trigger a valve closure.[121]

PG&E proposes to install RCVs on DOT-defined gas transmission pipeline segments within Class 3 and 4 areas that exceed minimum threshold criteria for pipe size and operating pressure as defined using a PIR calculation.[122] PIR means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property.[123] For more populated Class 3 HCA and Class 4 areas, the minimum threshold criteria are reduced to recognize the higher potential consequence.[124]

Specifically, PG&E will install RCVs on all DOT-defined gas transmission pipelines within Class 3 and 4 areas that meet one of the following criteria:

PIR > 200 feet for pipe located in Class 3 areas.

PIR > 150 feet for pipe segments located in areas with a predominance of Class 3 HCA.

PIR > 100 feet for pipe located in Class 4 areas.[125]

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[121] Ex. 2, PG&E Direct, p. 4-24, lines 5-9.

[122] Ex. 2, PG&E Direct, p. 4-9, lines 23-28.

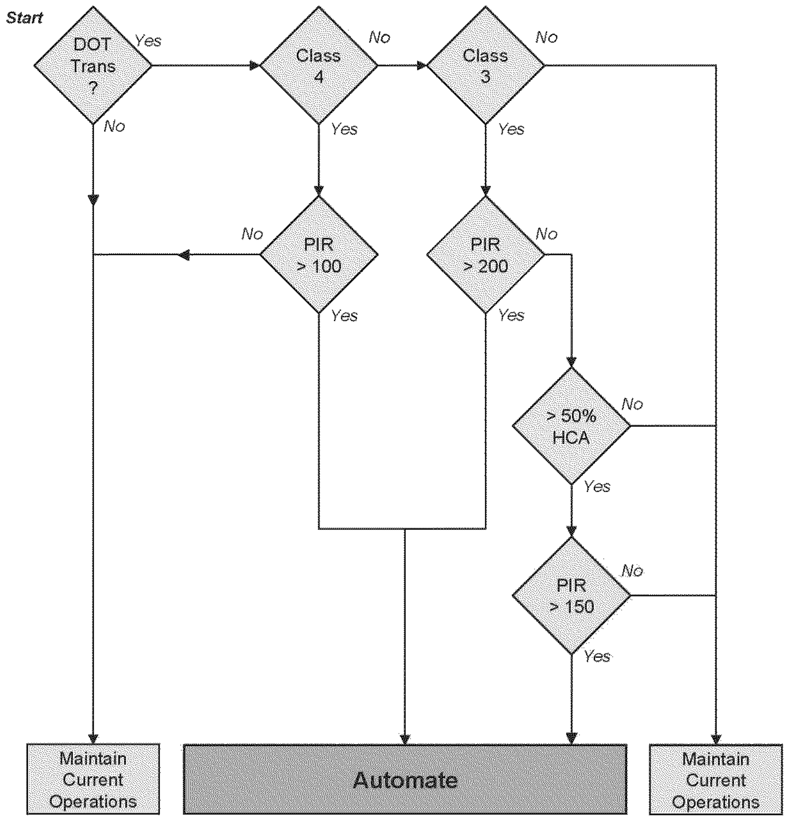
[123] 49 CFR § 192.903, subpart 4.c.

[124] Ex. 2, PG&E Direct, p. 4-9, lines 28-30.

[125] Ex. 1, PG&E's Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, p. 23.

The following decision tree illustrates the evaluation of population density:

FIGURE 4
PACIFIC GAS AND ELECTRIC COMPANY
DECISION TREE – POPULATION DENSITY



PG&E will install ASVs, which are automatically closed by local controls at the valve site, on certain pipelines in populated areas that cross active earthquake faults. ASVs will be installed on DOT-defined gas transmission pipelines within Class 3 and 4 areas and HCA Class 1 and 2 areas that exceed minimum threshold criteria for pipe size and operating pressure, and cross active faults that have a significant probability of rupturing a pipeline under maximum anticipated seismic event conditions.[126]

PG&E will install ASV capability on all pipeline segments crossing active earthquake

[126] Ex. 2, PG&E Direct, p. 4-9, line 31—p. 4-10, line 4.

faults that meet the following criteria:

- The segment is in a Class 3, Class 4, or Class 1 or 2 HCA location, and the line segment has a PIR of greater than or equal to 150 feet.
- The earthquake fault is deemed a significant risk of causing a pipeline rupture as defined by the potential magnitude and likely frequency of a major earthquake event and the susceptibility of the pipe segment to rupture during a major event.
    - The earthquake fault is considered active and is identified as having a greater than two percent probability of a 6.7 or greater magnitude earthquake event within the next 30 years.
    - The rupture risk to the pipeline has not been mitigated by pipeline design.[127]

Depicted below is PG&E's Earthquake Fault Crossing Decision Tree.

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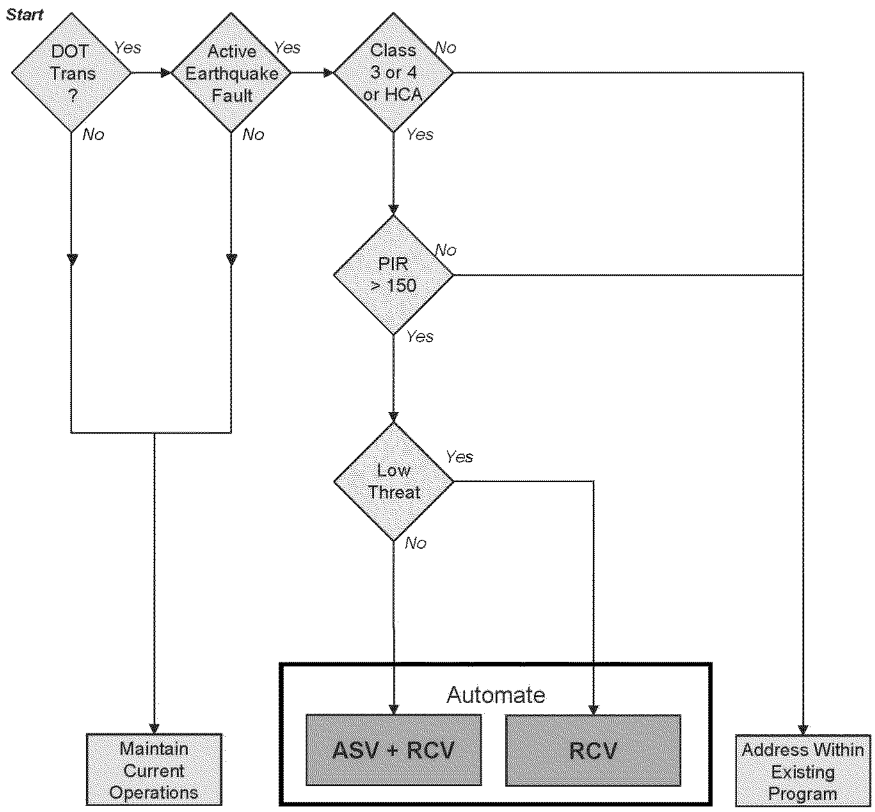
[127] Ex. 1, PG&E's Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, pp. 24-25.

FIGURE 5
PACIFIC GAS AND ELECTRIC COMPANY
DECISION TREE – EARTHQUAKE FAULT CROSSING



During Phase 1, PG&E proposes to replace, automate and upgrade 228 isolation valves, as part of 80 separate projects.[128]

Installation of automated valves on major pipelines in heavily populated areas increases emergency preparedness, and may reduce property damage and the danger to emergency personnel and the public in the event of a pipeline rupture.[129] PG&E believes the expansion of automated isolation capability is an important part of an overall emergency response system and will help restore public confidence in the safety of natural gas pipeline systems.[130] In the event

[128] Ex. 2, PG&E Direct, pp. 4-38—4-39.

[129] Ex. 2, PG&E Direct, p. 4-29, lines 11-14.

[130] Ex. 2, PG&E Direct, p. 4-29, lines 27-29.

of a pipeline rupture, automated isolation capability may: (1) minimize property damage by eliminating the primary fuel source for a pipeline rupture ignited fire in less time; (2) increase safety to emergency responders by allowing them to perform their actions unhindered by the high heat intensity flame created by a natural gas fire and allowing them to better plan their response by minimizing the uncertainty of when the natural gas fuel source will be shut-off; and (3) minimize the quantity of natural gas released during a pipeline rupture, thereby reducing the environmental impact and containing the loss of gas.[131] The Commission should approve PG&E's Valve Automation Program because it provides an important safety benefit.

A. DRA's Proposal For Fewer Automated Valves At Greater Intervals Should Be Rejected

PG&E designed the spacing of automated valves in its Valve Automation Program using the following guidelines:

- Valve spacing distances should limit the potential number of customers being fed off of a pipe segment to no more than 50,000.
- The maximum spacing between valves is targeted to be 8 miles for Class 3 locations, and 5 miles for Class 4 locations.[132]

These guidelines utilize the valve spacing requirements specified in the Code of Federal Regulations for pipelines in Class 3 and 4 areas. Generally, these guidelines target less than 10 minutes for blowdown for a full pipeline rupture.[133]

DRA recommends that PG&E install ASVs on seismic fault crossings (as PG&E has proposed), but only automate approximately 45 existing valves in which PG&E would simply be required to add an actuator to an existing valve.[134] With the exception of automated valves at

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[131] Ex. 2, p. 4-29, lines 14-26.

[132] Ex. 1, PG&E's Natural Gas Transmission Pipeline Replacement Or Testing Implementation Plan, p. 27.

[133] Id.

[134] Tr. (Oh), p. 2030, line 23—p. 2031, line 15.

seismic crossings, DRA does *not* recommend the following: (1) replacement of an existing valve with a new automated valve assembly; (2) installation of a new automated valve where no valve currently exists; (3) upgrading an existing automated valve which is already automated but requires a hardware or software upgrade; and (4) automation or replacement of an existing valve in a vault below a roadway.[135] DRA's proposal did not consider public safety or customer impacts, and should be rejected.

First, DRA's proposal elevates costs over public safety. As DRA's valve witness, Jerry Oh, testified, tighter automated valve spacing results in a "higher level of safety," than greater valve spacing.[136] When asked "why wouldn't it make sense to adopt DRA's proposal which allows you to install about 50 valves in existing sites which is much less expensive than PG&E's proposal," PG&E's valve witness Dan Menegus explained:

> Part of getting the most value, safety value from automated valves is you want to make sure you automate valves at both ends of the segment.[137]

There are many cases where only valves at one end of the segment would be automated under DRA's proposal, and therefore that individual segment would not be automated. PG&E's valve witness Mr. Menegus provided an example of what would happen on the San Francisco Peninsula if DRA's proposal were adopted, and concluded that, if PG&E were only to automate existing valves and were not to replace any valves, only 10 percent of the segments on the San Francisco Peninsula would be fully automated.[138]

Second, DRA did not take customer impacts into account.[139] A significant increase to automated valve spacing would generally lead to a corresponding significant increase to the service impacts and potential consequences in the event the automated valves closed, particularly

[135] Tr. (Oh), p. 2031, line 16—p. 2033, line 13.

[136] Tr. (Oh), p. 2041, lines 5-8.

[137] Tr. (Menegus), p. 1271, line 7—p. 1272, line 16.

[138] Tr. (Menegus), p. 1272, lines 17-27.

[139] Tr. (Oh), p. 2044, line 26—p. 2045, line 20.

in heavily populated areas where there are many taps off of pipelines that supply gas to distribution systems and major customers. Many more neighborhoods would be without gas and isolated under these circumstances. Taps to major distribution feeds are typically connected to both sides of a mainline valve, which are spaced at a maximum interval of eight miles in Class 3 locations. Increasing the spacing beyond the code specified spacing would put these major feeds at risk.[140] For example, DRA's proposal would result in a 34 mile segment on Line 101, and a 29 mile segment of Line 109 (both on the San Francisco Peninsula) with no automated valves.[141] As PG&E's valve witness Mr. Menegus concluded, "I don't think isolating a 29-mile section through a heavily populated area would be a very prudent thing to do."[142]

B. PG&E Should Not Be Required To Install ASVs Instead Of RCVs

PG&E proposes to install RCVs, not ASVs, in the areas selected for automation under the Pipeline Density decision tree. TURN proposes instead that PG&E be required to install ASVs in those areas. Given the potential for false closures and PG&E's lack of experience with ASVs, PG&E urges the Commission to reject TURN's proposal.

PG&E's greatest concern associated with ASVs is the risk of false or inadvertent closure.[143] This is due to the fact that the complexity of controls to accurately detect a rupture in a pipeline is challenging, especially in situations where there are interconnected pipeline facilities. Because ASVs are most often closed based upon low pressure or rapid pressure decline, the likelihood of a false closure is greatest when system flow demands are the highest, and at points closest to large system loads where there would be less time to react to a false closure.[144] The consequences of an inadvertent ASV closure can be significant, because an ASV is likely to be falsely triggered when demand is at its peak; for example, on a cold winter

[140] Ex. 21, PG&E Rebuttal, p. 6-6, lines 12-21.

[141] Tr. (Menegus), p. 1275, lines 16-28.

[142] Tr. (Menegus), p. 1276, lines 18-20.

[143] Ex. 2, PG&E Direct, p. 4-25, lines 4-5.

[144] Ex. 2, PG&E Direct, p. 4-25, lines 5-13.

morning when large numbers of customers wake up, turn on their heat, take a hot shower, and cook breakfast.[145] Moreover, if PG&E were to take steps to design the SCADA system and controls so as to minimize the risk of false closures, it would significantly increase the complexity of controls, which thereby increases the risk of the control system not performing properly.[146]

PG&E urges the Commission to adopt PG&E's proposal to install RCVs under the Population Density decision tree, until PG&E can further study the use of ASVs and the risk of false closure. The automated valves PG&E proposes to install will be equipped with both ASV and RCV capability.[147] To enable the ASV operating mode only requires a minor software configuration change.[148] It is possible that, in the future, it will make sense for PG&E to operate automated valves in densely populated areas in ASV mode. In the meantime, PG&E plans to use alarms on RCVs in its Gas Control that would monitor when an ASV would have closed had the valve been operating in ASV mode. PG&E plans to use these data to study the potential to shift some or all of the RCVs to ASV mode in the future.[149]

PG&E does propose to use ASVs at certain pipeline earthquake fault crossings which are a unique threat situation. Emergency responders would likely be dealing with multiple locations after a major earthquake event, so pipeline automatic isolation capability at the identified fault crossings has high value for this situation. At these earthquake fault crossing locations, the valves would be installed in close vicinity to the fault, thereby providing quicker and more reliable pipeline rupture detection capability.[150] For this type of installation, the risk of false or inadvertent closure is greatly reduced.

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[145] Ex. 21, PG&E Rebuttal, p. 6-4, lines 25-28.

[146] Tr. (Menegus), p. 1313, line 27—p. 1314, line 18.

[147] Ex. 21, PG&E Rebuttal, p. 6-5, lines 5-7.

[148] Ex. 21, PG&E Rebuttal, p. 6-5, lines 20-21.

[149] Tr. (Menegus), p. 1364, lines 1-23.

[150] Ex. 2, PG&E Direct, p. 4-25, lines 30-32.

C. PG&E's Population Density Decision Tree Properly Prioritizes Valve Automation

PG&E proposes to install automated valves where they can have the greatest potential safety impact—on pipeline segments in Class 3 and 4 areas that exceed minimum threshold criteria for pipe size and operating pressure as defined using a PIR calculation. For higher populated areas (i.e. Class 3 HCA and Class 4 areas), the minimum threshold criteria are reduced to recognize the higher potential consequence.[151] DRA's valve witness Oh admitted that PG&E's proposal results in an appropriate prioritization under Public Utilities Code Section 957(a)(1)(A).[152] Under DRA's proposal to only automate existing valves, PG&E would be deferring the automation of older valves that are underground in populated areas, in favor of automating newer valves in primarily rural areas. DRA's proposal did not consider whether it was appropriate to automate valves in rural areas before urban and suburban areas; in fact, DRA's valve witness testified that that would *not* be the right safety priority.[153]

In addition, TURN takes issue with PG&E's use of PIR, and recommends instead that PG&E should consider pipe diameter rather than PIR as the primary factor guiding the automation of valves.[154] PIR, which is a function of pipe diameter and maximum allowable operating pressure, is proportional to the quantity of energy contained in a section of pipe. It takes into account the significant impact that pressure has on the heat flux intensity of an ignited pipeline. The use of PIR in PG&E's decision trees will essentially utilize pipe diameter as the decision factor for pipelines with similar operating pressures, but will elevate those pipelines that are slightly smaller in diameter and operating at a much higher pressure than a larger diameter pipeline.[155]

Adoption of TURN's proposal to use solely pipeline diameter would result in the wrong

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[151] Ex. 2, PG&E Direct, p. 4-9, lines 23-30.

[152] Tr. (Oh), p. 2037, lines 3-23; p. 2044, lines 9-13.

[153] Tr. (Oh), p. 2049, lines 19-28.

[154] Ex. 131, TURN Direct (Kuprewicz), p. 51.

[155] Ex. 21, PG&E Rebuttal, p. 6-9, lines 3-15.

prioritization scheme. For example, if PG&E operates a 24-inch pipeline operating at 145 psig, and a 20-inch pipeline operating at 2,160 psig, the PIR is 199 feet for the 24-inch pipe and 641 feet for the 20 inch pipe. If these two pipelines traversed equally populated areas, it would be unreasonable to prioritize installing automated valves on the 24-inch pipelines ahead of installing them on the 20-inch pipeline.[156] As explained in the rebuttal testimony of Mark Stephens (Ex. 21, Chapter 7), the PIR model has proved to be an accurate predictor of an area within which the extent of property damage and the chance of serious or fatal injury would be expected to be significant in the event of an ignited rupture of a gas transmission pipeline. TURN's proposal to consider *only* pipeline diameter should be rejected.

D. PG&E's Proposed SCADA Enhancements Should Be Approved

As part of the Valve Automation Program, PG&E will enhance its SCADA system to allow operators in its Gas Control Center to detect a rupture more quickly and isolate the affected section of pipeline. PG&E proposes SCADA enhancements in the following categories:

- Additional information relating to pressure, flows and other critical gas system data with the SCADA system that will enhance gas controllers' knowledge of gas system conditions and support early detection of, and better understanding of, an excursion from anticipated conditions.
- Additional training for operators in detection of events and proper response to specific events.
- Advanced SCADA logic, tools and technologies that identify abnormalities and bring them to the attention of the operator.[157]

While no party opposes approval of PG&E's proposed SCADA enhancements, DRA proposes to eliminate approximately $4 million of PG&E's request on the grounds that "training expenses should be included in PG&E's GRC funding," and "inclusion of training expenses as

[156] Ex. 21, PG&E Rebuttal, p. 6-9, lines 6-11.

[157] Ex. 2, PG&E Direct, p. 4-26, line 30—4-27, line 6.

part of PSEP is redundant and should be denied."[158] It is appropriate to include costs for training on PG&E's SCADA enhancements as part of PSEP because it is training for new tools, technology and processes required to achieve the goals of the Valve Automation Program.[159]

E. PG&E's Valve Automation Cost Estimates Are Reasonable And Should Be Adopted

The Valve Automation Program consists of capital and expense work. The capital work is primarily related to the valve automation projects. The expense work consists of SCADA enhancement projects, including additional Gas Operator training requirements, and recurring incremental operating and maintenance ("O&M") expenses associated with the new equipment. PG&E forecasts spending $132.5 million in capital and $11.1 million in expense for 2011-2014 for the Valve Automation Program.

DRA recommends that the Commission disregard PG&E's cost estimates for the Valve Automation Program on the grounds that PG&E's forecasts are conceptual in nature and the actual costs of 2011 valve automation projects have varied from the forecasts for these projects.[160] PG&E's cost estimates were at a Class 4 estimate level, because the project definition was less than 15 percent at the time of the estimate's development.[161] Therefore, it can be expected that there will be significant variation between forecast and actual costs at the individual project level, but that the combined actual costs of a group of projects would be closer to the total estimated cost for that group of projects.[162] This was demonstrated by the 2011 actual costs for the "launch" valve automation projects. While there was significant variation between forecasted and actual costs for each of the eight 2011 Valve Automation Launch projects, in the aggregate PG&E's actual costs were 98.6% of the forecast costs, resulting in a

[158] Ex. 120, DRA Direct (Oh), p. 16.

[159] Ex. 21, PG&E Rebuttal, p. 6-18, lines 30-33.

[160] Ex. 120, DRA Direct (Oh), pp. 6-11.

[161] Ex. 21, PG&E Rebuttal, p. 6-16, lines 5-9.

[162] Ex. 21, PG&E Rebuttal, p. 6-16, lines 10-15.

variance of only 1.4%.[163]

PG&E has reasonably estimated the costs of its Valve Automation Program, and its estimates should be approved by the Commission.

IV. THE PIPELINE RECORDS INTEGRATION PROJECT IS NECESSARY TO COMPLY WITH A NEW STANDARD FOR VALIDATING MAOP

On January 3, 2011, the NTSB issued an urgent recommendation to all pipeline operators recommending that they validate —through records—the MAOP of all gas transmission lines located in HCAs. The NTSB further recommended that the standard for this search should be that all information used to validate a pipeline's MAOP should be traceable, verifiable, and complete.[164] In Decision 11-06-017, the Commission ordered PG&E to complete its MAOP determination based on pipeline features for all gas transmission pipelines.[165]

This represents a sea change in the way in which operators could establish the MAOP for pipelines on their systems.[166] Prior to January 3, 2011, federal regulations allowed operators to establish MAOP using any one of four possible methods: (1) calculated based upon the design of each of the components of the pipelines; (2) through a strength test; (3) the highest actual operating pressure during the five years preceding July 1, 1970; or (4) the pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.[167] The January 3, 2011 NTSB recommendation and subsequent Commission order materially altered how an operator could establish the MAOP of its pipelines. Now, a strength test is the *only* permitted means to establish the MAOP of a pipeline. In addition, although the only permitted means for

[163] Ex. 21, PG&E Rebuttal, p. 6-17, lines 5-14.

[164] Ex. 2, PG&E Direct, p. 5-5, line 28—p. 5-6, line 2.

[165] D. 11-06-017, Ordering Paragraph 1; Conclusion of Law 1.

[166] In addition, the *Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011* was signed into law by President Obama on January 3, 2012. It requires, among other things, that each pipeline operator verify its records for transmission pipelines in Class 3 and 4 and Class 1 and 2 HCAs and confirm the MAOP of the pipelines. (HR 2845, Section 23).

[167] 49 CFR § 192.619 (2011); Tr. (Howe), p. 1218, line 26—p. 1220, line 13.

establishing MAOP is through a strength test, the Commission has nonetheless ordered PG&E to complete its MAOP Validation Project to validate the MAOP of its pipeline as an interim measure, until pipelines without a documented pressure test can be pressure tested or replaced. PG&E's witness with 30 years' experience in the electric and natural gas utility industry described the NTSB's safety recommendation P-10-2 as follows:

> What I see in that standard for determining maximum allowable operating pressure is that prior to this standard the federal regulations in 1970 prescribed four different methodologies for determining maximum allowable operating pressure, where this directive, this recommendation, specifies one and one only.[168]

In other words, the CPUC has ended grandfathering in California; operators in California can no longer rely on the highest operating pressure in the five years preceding implementation of the federal regulations in 1970 to establish MAOP for a pipeline installed prior to the effective date of federal regulations.[169] Furthermore, the Pipeline and Hazardous Materials and Safety Administration ("PHMSA") recently issued an Advisory that further defines the terms traceable, verifiable, and complete.[170]

PG&E's Pipeline Records Integration Project is designed to meet this new standard, and comprises two separate work efforts: (1) MAOP Validation; and (2) the Gas Transmission Asset Management ("GTAM") Project. The MAOP Validation Project is necessary to meet the NTSB recommendation and Commission mandate that PG&E validate the MAOP of its gas transmission pipelines through traceable, verifiable, and complete records. The GTAM Project is necessary in order to establish a system that will allow PG&E to continue to meet this new regulatory standard on a going-forward basis.

[168] Tr. (Howe), p. 1157, lines 14-24; see also Tr. (Singh), p. 1711, lines 11-13.

[169] Tr. (Howe), p. 1226, lines 17-27.

[170] Notice, 77 Fed.Reg. 26822 (May 7, 2012).

A. The MAOP Validation Project Is Necessary To Comply With The New Requirement To Validate MAOP Through Traceable, Verifiable And Complete Records

The MAOP Validation Project provides the means for compliance with the Commission's order to validate the MAOP of all gas transmission pipelines using traceable, verifiable, and complete records.[171] The MAOP Project has been divided into three parts. Part 1 (which has already been completed at shareholder expense) involved a comprehensive search to locate and scan all strength test records for Class 3, 4 and Class 1 and 2 HCAs, and load them into an interim electronic database.[172] Part 2 is focused on developing a Pipeline Features List ("PFL") and performing MAOP validation for those HCA pipeline segments.[173] The PFLs are created using information from the original source documents that PG&E has collected, and is a comprehensive list that includes every component on a foot-by-foot basis for the pipeline, and their associated specifications.[174] Information from the PFL is used to calculate the design-basis MAOP for each underlying pipeline component.[175] Part 3 consists of the MAOP validation for all remaining (non-HCA) pipelines in PG&E's system.[176] The MAOP Validation Project is scheduled to be completed in 2013.[177]

Upon completing the MAOP Validation Project, PG&E will have validated the MAOP for each segment of its transmission system using traceable, verifiable, and complete source documents, in order to comply with the NTSB's recommendation and Commission mandate.[178] It bears repeating that pipelines for which a prior strength test cannot be documented will be strength tested or replaced, even though the MAOP for these pipelines has been validated through the MAOP Validation Project.

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171 Ex. 21, PG&E Rebuttal, p. 11-5, lines 1-4.

172 Ex. 2, PG&E Direct, p. 5-8, line 26—p. 5-9, line 5.

173 Ex. 2, PG&E Direct, p. 5-9, lines 8-10.

174 Ex. 2, PG&E Direct, p. 5-9, lines 16-20; Tr. (Singh), p. 1631, lines 3-6.

175 Ex. 2, PG&E Direct, p. 5-10, line 17—p. 5-11, line 18.

176 Ex. 2, PG&E Direct, p. 5-12, lines 10-20.

177 Ex. 2, PG&E Direct, p. 5-14, line 1.

178 Ex. 2, PG&E Direct, p. 5-12, line 30—p. 5-13, line 2; Ex. 21, PG&E Rebuttal, p. 11-5, lines 5-7.

B. GTAM Is Necessary To Comply With The New Traceable, Verifiable And Complete Standard On A Going Forward Basis

The new traceable, verifiable, and complete standard not only has to be met as of today, but needs to be met in the future as well. As PG&E witness Steve Whelan testified:

> [I]t is not just an obligation to validate the MAOP today, but it is also an ongoing obligation to be able to demonstrate the MAOP to the traceable, verifiable and complete standard. So GTAM is focused on how can we keep that asset information complete, that verifiable, traceable and complete standard, is every day we do work on the pipeline system we are cutting our components, adding new components. And as we change the characteristics of the pipeline system, we need to be able to continue to update it to that new standard.[179]

The GTAM Project is creating a platform such that new information about pipeline components can be collected and maintained to a traceable, verifiable, and complete standard.[180] It accomplishes that goal by:

- Upgrading PG&E's current GIS to reflect an improved "linear referencing model," which will allow PG&E to view and analyze pipeline features, characteristics and event history relative to specific reference points along the entire length of its gas transmission pipelines.
- Developing a comprehensive process and system to trace and track materials from receipt by PG&E through the operating life of the component.
- Eliminating paper-based work processes and implementing automated work processes that manage leak survey, mark and locate, and maintenance work from scheduling of work, field capture of information, verification and quality review of field-captured data, and updating of the integrated information management systems.
- Developing tools to support the integration of all pipeline asset data to provide the

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[179] Tr. (Whelan), p. 1751, line 21—1752, line 10.

[180] Tr. (Whelan), p. 1634, lines 3-23.

full picture of asset health and condition with enhanced ability to perform risk and integrity analytics.[181]

While there may be other ways to comply with this new regulatory standard on an on-going basis (*e.g.* an enhanced paper-based system), the GTAM Project is an efficient way to ensure compliance in the future by consolidating pipeline information into core enterprise electronic databases.

C. PG&E's Cost Estimates For The Pipeline Records Integration Project Are Reasonable And Should Be Adopted

The total estimated cost to complete the MAOP Project is approximately $271.9 million.[182] Of that, PG&E is seeking cost recovery for $107.1 million for work to be performed in 2012 and 2013.[183] This amount is sufficient to complete the MAOP Validation Project.[184] The total estimated cost to complete the GTAM project is $123.6 million for 2011-2104. Of that, approximately $8 million was forecasted to be spent in 2011, which PG&E has agreed that shareholders will bear.[185]

PG&E used a "bottoms-up" methodology to forecast the costs to complete the MAOP Validation and GTAM Projects, which provides the most accurate forecasting methodology under the circumstances.[186] Both projects represent substantial undertakings where the cost to perform the work has not been included in prior periods. In cases such as this one in which a new activity has not traditionally been part of the operation of the business, historical spending patterns are poor predictors of future costs.[187] The bottoms-up methodology provides a more accurate and transparent forecast of future costs for the MAOP Validation and GTAM Projects

[181] Ex. 2, PG&E Direct, p. 5-16, lines 8-32.
[182] Ex. 2, PG&E Direct, p. 5-13, lines 6-7.
[183] Ex. 2, PG&E Direct, p. 5-13, lines 12-22.
[184] Tr. (Whelan), p. 1616, lines 18-22.
[185] Ex. 2, PG&E Direct, p. 5-26, line 17—p. 5-27, line 3.
[186] Ex. 21, PG&E Rebuttal, p. 11-8, lines 19-21.
[187] Ex. 21, PG&E Rebuttal, p. 11-9, lines 1-10.

because the bottoms-up methodology takes into account the actual scope of planned work, and identifies the individual components of the forecast (instead of relying on a single, imbedded actual cost).[188] The accuracy of the forecast is underscored by the fact that the actual costs incurred in 2011 for MAOP validation were within 98 percent of the forecast.[189]

PG&E's cost forecasts for completing the Pipeline Records Integration Project are reasonable and should be adopted by the Commission.

D. The Pipeline Records Integration Program Costs Are Incremental To Current Rates

The entire GTAM Project forecast is incremental to PG&E's funding in its 2011 General Rate Case ("GRC") and 2011 Gas Transmission and Storage ("GT&S") Rate Case. In the case of the 2011 GRC, PG&E requested funding to maintain and operate existing systems, plus funding for certain enterprise enhancements.[190] The enterprise enhancements requested in the 2011 GRC did not focus on gas transmission and did not anticipate the substantial increase in data reliability and quality requirements now recommended by the NTSB and the Commission to enhance pipeline safety.[191] The only gas transmission work envisioned in the 2011 GRC was to upgrade the gas transmission GIS system from version 1.0 to version 2.0.[192] This work has been completed and is not duplicated in the GTAM proposal.[193] In fact, GTAM builds on the GIS upgrade by adding Linear Referencing to GIS and SAP, integrating both systems, and providing links to source documentation.[194]

The amounts authorized by Decision 11-04-031 approving the Gas Accord V Settlement Agreement provide for modest system enhancements to the gas accounting/scheduling system

[188] Ex. 21, p. 11-9, lines 12-18.

[189] Tr. (Whelan), p. 1718, lines 18-25.

[190] Ex. 2, PG&E Direct, p. 5-30, lines 15-17.

[191] Ex. 21, PG&E Rebuttal, p. 11-15, lines 30-33.

[192] Ex. 21, PG&E Rebuttal, p. 11-15, lines 18-20.

[193] Ex. 21, PG&E Rebuttal, p. 11-15, lines 20-21.

[194] Ex. 21, PG&E Rebuttal, p. 11-15, lines 21-24.

(InsideTrack), SCADA, and billing systems.[195] The total amount of IT system enhancements proposed for the GT&S business in 2012 was approximately $2.8 million.[196] The GTAM Project was not forecasted as part of Gas Accord V.[197]

Nor was there any funding in either the 2011 GRC or the 2011 GT&S Rate Case for MAOP validation.[198] As discussed above, the MAOP Validation Project is being undertaken to comply with a new regulatory standard for validating MAOP of transmission pipelines. It could not have been, and was not, forecasted as part of a prior rate case.

V. THE PROPOSED INTERIM SAFETY ENHANCEMENT MEASURES SHOULD BE APPROVED

PG&E's Pipeline Safety Enhancement Plan includes the following interim safety enhancement measures, in addition to the MAOP validation discussed above: (1) pressure reductions; and (2) increased leak surveys and patrols.

A. PG&E's Proposed Process For Reducing Pressure As An Interim Safety Measure Should Be Approved

An interim pressure reduction may be called for on a pipeline segment under the following circumstances: (1) the MAOP Validation process (described above) identifies a segment where the calculated MAOP is lower than current operating pressure and pressure should be reduced to the calculated MAOP on an interim basis; or (2) the Pipeline Program Decision Trees identify an interim pressure reduction as a recommended mitigation measure. Under the second scenario, the recommended action for some pipeline segments is to reduce pressure on an interim basis until a later corrective action can be accomplished.[199] If a pressure reduction is indicated for a pipe segment under the Pipeline Program Decision Trees, PG&E will reduce the operating pressure on that segment by 20 pounds per square inch gauge ("psig")

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[195] Ex. 2, PG&E Direct, p. 5-30, lines 10-14.

[196] Ex. 21, PG&E Rebuttal, p. 11-2, lines 26-28.

[197] Ex. 21, PG&E Rebuttal, p. 11-15, lines 8-10.

[198] Ex. 21, PG&E Rebuttal, p. 11-3, lines 9-12.

[199] Ex. 2, PG&E Direct, p. 6-6, lines 19-24.

below the segment MAOP until corrective actions have been accomplished.[200] PG&E has already implemented certain interim pressure reductions and will complete its implementation of interim pressure reductions called for in the Pipeline Modernization Program Decision Trees no later than 30 days after final CPUC approval of the Pipeline Safety Enhancement Plan.[201]

1. PG&E's Costs Forecasts For Implementation Of Interim Pressure Reductions Should Be Approved

PG&E forecasts $2.1 million as the cost to implement these pressure reductions, in order to hire four full-time Senior Gas Engineers dedicated to the Pipeline Safety Enhancement Plan from 2012-2014.[202] These four full-time engineers are needed to perform hydraulic modeling necessary to analyze impacts of pressure reductions and operations necessary to accommodate hydrotesting, in-line inspection, and pipeline replacement.[203] The four new Senior Gas Engineers will be performing the following work:

- New Analysis of Feasibility of Interim Pressure Reductions: As part of the PSEP, PG&E must review, for each of the 450+ regulator stations in our gas transmission system, whether an interim pressure reduction can be made and still ensure we meet our Abnormal Peak Day and Cold Winter Day design criteria and system inventory requirements.[204]
- Clearances Due to Hydrotesting: To ensure that customers are provided reliable service while sections of the gas transmission system are taken out of service during PSEP project execution, highly detailed operational hydraulic analyses are required as part of each clearance. From 2012 through 2014, PG&E is expecting to do approximately 295 hydrotests.[205]

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[200] Ex. 2, PG&E Direct, p. 6-8, lines 15-17.

[201] Ex. 2, PG&E Direct, p. 6-8, lines 23-31.

[202] Ex. 2, PG&E Direct, p. 6-9, lines 2-4.

[203] Ex. 2, PG&E Direct, p. 6-9, lines 9-11.

[204] Ex. 21, PG&E Rebuttal, p. 12-4, lines 27-30.

[205] Ex. 21, PG&E Rebuttal, p. 12-5, lines 16-26.

- Increase in Pipeline Replacement and Valve Automation: The increased pipeline replacements under PSEP will require PG&E's planning engineers to perform system investment plans to ensure that we meet expected customer demand with strategic, cost-efficient investments in the gas transmission system.[206]
- Ongoing Pressure Reductions: Each unique pressure reduction identified by MAOP validation requires hydraulic analyses prior to and after implementing the reduction. Because we have not yet completed MAOP validation on over 4,000 miles of non-HCA pipeline segments, this will present an ongoing workload increase.[207]

2. PG&E Will Minimize Customer Impacts From Pressure Reductions And Other PSEP Work

PG&E has specific design criteria standards to avoid customer outages and ensure safe and reliable service. Any interim pressure reduction implemented under the PSEP will consider the safety impacts of customer outages along with pipeline integrity safety margins. PG&E will reduce operating pressure on a segment indicated by the Pipeline Program Decision Tree by 20 psig below MOP, provided that design criteria standards can be met, thereby avoiding the safety issues associated with customer outages described below. If the design standard cannot be met with the 20 psig interim pressure reduction, PG&E will reduce pressure to a level at which the design standard can be met.

Failure to maintain continuity of service to customers can be a safety and health issue, and can have serious economic impacts to customers and the public. Lowered pressures can cause the loss of service to core customers, which will result in the loss of heat in winter, hot water, and gas for cooking. Outages will cause pilots on customer equipment to extinguish. Subsequent re-pressurization of the system without appropriate safety measures could result in gas escaping into structures. Customers may try to relight appliances themselves, or use unsafe

[206] Ex. 21, PG&E Rebuttal, p. 12-5, lines 27-32.

[207] Ex. 21, PG&E Rebuttal, p. 12-6, lines 12-23.

methods to heat their homes (e.g., propane appliances).[208] For these reasons, any pipeline pressure reduction must take into consideration the public safety impacts from the loss of gas service to customers.[209]

PG&E is committed to working with its customers to ensure minimal disruptions while PG&E is completing the significant work planned under the PSEP. PG&E is well aware how critical PG&E's gas service is to many of our customers, including refineries, electric generators, and other critical energy infrastructure providers.[210] PG&E has gone to great lengths to coordinate our planned outages with such customers, including providing service from alternative feeds, or allowing a customer to be served by a third party's private pipeline. In addition, PG&E works closely with the California Independent System Operator Corporation to ensure continued reliability of the state's electric system as PG&E makes the necessary changes and upgrades to its gas system.[211]

However, a particular notice period should not be prescribed, for a number of reasons. First, the scheduling of work on the PG&E gas transmission system is very complex, and typically involves procuring multiple permits, scheduling of construction resources (both PG&E and contractors), and coordinating outages with interconnecting pipelines.[212] Requiring a set period of advance notice prior to construction would be extremely difficult and would result in many changes to the outage date as the project moves through various stages of planning, design, permitting and construction scheduling.[213] In addition, if a notice period were required, it is likely that PG&E would have to issue a significant number of outage notices that would be cancelled; many customers would have to make unnecessary arrangements for an outage that

[208] Ex. 2, PG&E Direct, p. 6-7, lines 15-26.

[209] Ex. 2, PG&E Direct, p. 6-7, lines 1-3.

[210] Ex. 21, PG&E Rebuttal, p. 12-8, lines 3-9.

[211] Ex. 21, PG&E Rebuttal, p. 12-8, lines 9-15.

[212] Ex. 21, PG&E Rebuttal, p. 12-7, lines 17-20.

[213] Ex. 21, PG&E Rebuttal, p. 12-7, lines 20-23.

may never happen.[214]

B. PG&E's Increased Leak Surveys And Patrols Should Be Approved

For those pipe segments that are in Class 4, Class 3, Class 2 and Class 1 HCAs and do not have records of prior pressure testing, PG&E proposes to conduct leak surveys six times per year until the segment is tested, or replaced. PG&E also will perform leak surveys six times per year on those segments operating under 30 percent SMYS in Class 2 to 4 and Class 1 HCAs that are planned to be strength tested and inspected in Phase 2.[215]

PG&E also is conducting additional patrols on the same segments of its gas transmission system discussed above. These patrols will be conducted six times annually.[216] The Backbone Transmission system will continue to be patrolled monthly (quarterly code compliance patrols and monthly reliability patrols).[217] PG&E's forecast of $1.113 million[218] to perform these increased leak surveys and patrols is reasonable and should be adopted.

VI. PG&E'S CONTINGENCY REQUEST IS REASONABLE AND SHOULD BE APPROVED

PG&E retained PricewaterhouseCoopers LLP ("PwC") to assess the risk profiles of each component project in the PSEP to quantify project risks and establish a reasonable risk-based allowance for the preliminary project estimates.[219] In order to develop a reasonable, risk-based contingency, PwC:

- Compiled and analyzed the detailed estimate documentation, calculations and workpapers.
- Conducted interviews with individuals and teams who prepared the base estimates to gain further insight into the basis for the estimates.

[214] Ex. 21, PG&E Rebuttal, p. 12-7, lines 27-30.
[215] Ex. 2, PG&E Direct, p. 6-12, lines 11-22.
[216] Ex. 2, PG&E Direct, p. 6-15, lines 3-7.
[217] Ex. 2, PG&E Direct, p. 6-15, lines 7-8.
[218] Ex. 2, PG&E Direct, p. 6-2, Table 6-1.
[219] Ex. 2, PG&E Direct, p. 7-3, lines 26-29.

- Facilitated workshops with the estimating teams and other project participants to establish the overall risk profile for each component project.
- Developed a Quantitative Risk Assessment ("QRA") contingency model, based on Monte Carlo simulations.
- Calculated estimated contingency amounts for each cost component's base estimate based on the outcomes of the QRA model.
- Compared the results of the QRA model and PwC approach to calculate a risk-based allowance for the PSEP.[220]

The typical use of a QRA is to compare the likelihood of completing a project within a given budget, or to determine the contingency necessary to align funding requirements with a company's "risk appetite."[221] Often, organizations implementing complex projects such as the PSEP (or those with a lower risk appetite) will require a certainty of 90 percent (P90).[222] In the case of the PSEP, the P80 range would require a 20 percent contingency, while the P90 establishes a 21 percent contingency.[223] Considering the current level of design certainty and the need for PG&E to establish a high level of funding confidence for this Program, PG&E adopted PwC's recommendation to use a P90 level for the PSEP contingency, which resulted in a range of 10 percent to 28 percent for each work scope, and an overall contingency request of $380.5 million (in expense and capital).[224]

The recommended 21 percent contingency is well within the reasonableness ranges established by general contingency guidelines contained in various tables established by industry groups, as summarized in Table 7-9 of Exhibit 2. Considering the project contingency guidelines summarized in Table 7-9,[225] a Class 4 estimate would typically include a contingency allowance

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[220] Ex. 2, PG&E Direct, p. 7-3, line 29—p. 7-4, line 15.

[221] Ex. 2, PG&E Direct, p. 7-40, lines 26-30.

[222] Ex. 2, PG&E Direct, p. 7-40, lines 35-36.

[223] Ex. 2, PG&E Direct, p. 7-41, lines 4-5.

[224] Ex. 2, PG&E Direct, p. 7-41, lines 5-9; p. 7-4, Table 7-2.

[225] Ex. 2, PG&E Direct, p. 7-44.

of up to 40 percent.[226] Therefore, PG&E's contingency allowance of 21 percent is significantly lower than the expected amount reflected in the industry guidelines.[227] PG&E's contingency request is a commercially reasonable contingency factor for financial planning for a risk-averse organization.[228] PG&E requests that the Commission adopt PG&E's contingency request.

VII. PG&E'S PROGRAM MANAGEMENT APPROACH IS SOUND AND SHOULD BE APPROVED

The successful delivery of a large program like PG&E's PSEP involves detailed planning, a comprehensive set of control tools and procedures that evolve with the program as projects move through their standard life cycles, and an overall governance approach that recognizes the need to manage a broad array of project and program risks.[229] PG&E proposes a comprehensive Program Management Structure to deliver the component projects in the PSEP in a timely, cost effective and high quality manner.[230] PG&E's approach is consistent with common industry practices for managing capital programs with multiple related projects or work streams, and it fully addresses the three key components of good project management: execution, oversight and assurance.[231] PG&E's comprehensive management framework includes an Executive Steering Committee, an External Advisory Board ("EAB"), a Program Manager, and a Program Management Office ("PMO").[232]

Since PG&E filed its PSEP in August 2011, PG&E has been formalizing its PMO organization structure, mobilizing resources, compiling and refining a comprehensive set or program management processes and procedures, developing integrated work plans and schedules, and establishing a formalized governance structure and control environment for the

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[226] A Class 4 estimate typically has a level of project definition of one percent to 15 percent, and an expected accuracy range of -15 percent to +50 percent. Ex. 2, PG&E Direct, p. 7-25, Figure 7-3.

[227] Ex. 2, PG&E Direct, p. 7-44, lines 17-19.

[228] Tr. (Caletka), p. 2128, lines 22-28.

[229] Ex. 2, PG&E Direct, p. 7-5, lines 25-29.

[230] Ex. 2, PG&E Direct, p. 7-5, lines 4-7.

[231] Ex. 2, PG&E Direct, pp. 7-7—7-8; Ex. 21, PG&E Rebuttal, p. 14-6, lines 16-18.

[232] Ex. 2, PG&E Direct, p. 7-8, Figure 7-1.

PSEP.[233] PG&E has retained two engineering/construction/project management firms—CH2M Hill and Parsons—to support the development of the PMO and various work stream management efforts, including the development of project management controls and procedures.[234] Detailed controls are in place and operating for active program work streams. PG&E is finalizing and will continue to update a consistent Program Execution Plan and Procedures Manual across all PSEP work streams.[235] PG&E is in the process of defining the full scope and charter of the EAB, which will be a group of experienced professionals (who are not PG&E employees) who will provide an important program advisory and assurance role.[236] The EAB will not have direct program execution responsibilities; the scope of the efforts of the external advisors and their compensation will not be affected by increases or decreases in the scope of the PSEP.[237]

PG&E's proposed governance approach and control environment is consistent with good industry practice,[238] and should be approved. Furthermore, PG&E's estimated costs of $34.8 million in capital and expense[239] for PSEP management reflects an industry standard estimating approach and a reasonable amount to deliver these essential services for a program of this magnitude.[240] PG&E requests that the Commission adopt PG&E's PSEP program management cost request.

VIII. PG&E'S COST ALLOCATION AND RECOVERY PROPOSAL IS JUST AND REASONABLE

A. The Commission Should Use The Ratemaking Process To Encourage A Strong Safety Focus

In the Order instituting this proceeding, the Commission raised the question of whether

[233] Ex. 21, PG&E Rebuttal, p. 15-1, lines 23-27.

[234] Ex. 21, PG&E Rebuttal, p. 15-5, lines 12-19.

[235] Ex. 21, PG&E Rebuttal, p. 15-5, lines 5-8.

[236] Ex. 21, PG&E Rebuttal, p. 15-6, lines 16-19; Tr. (Lechner), p. 1910, line 28—p. 1911, line 4.

[237] Ex. 21, PG&E Rebuttal, p. 15-6, lines 16-26.

[238] Ex. 2, PG&E Direct, p. 7-17, lines 18-19.

[239] Ex. 2, PG&E Direct, p. 7-2, Table 7-1.

[240] Ex. 2, PG&E Direct, p. 7-20, lines 15-18.

traditional cost of service ratemaking has resulted in a proper focus on safety issues.[241] One of the Commission's stated goals in the OIR is to consider "how we can align ratemaking policies, practices, and incentives to better reflect safety concerns and ensure ongoing commitments to public safety."[242] The Commission also determined in Decision 11-06-017 that PG&E's PSEP should include a shareholder/customer cost sharing proposal. The PSEP filing thus presents an important first case for the Commission to address, from a policy perspective, how best to use the ratemaking process to encourage safety.

Application of appropriate ratemaking principles will be essential if the Commission is to provide PG&E with both sound incentives and resources for making the investments and expenditures necessary to enhance its operations and assets consistent with the Commission's safety, reliability and rate-level goals. Witness Susan Tierney proposes five ratemaking principles to accomplish these objectives in this proceeding:

1. Regulators should set appropriate standards to assure investment in and operations of a system capable of providing reliable service and having high integrity to protect public and worker health and safety, at reasonable cost.

2. Regulators should establish and use ratemaking mechanisms and rate levels to support a level of capital investment and operations/maintenance expenditures that are fundamentally supportive of achievement of regulatory goals (such as safety standards).

3. Customers should pay prices (rates) that fully reflect the cost of providing them the goods and services used.

4. As it conducts proceedings to hold individual utilities accountable for past failures to meet regulatory standards, the Commission should separate such proceedings from rulemaking proceedings addressing the future behavior of all regulated companies.

5. While it is important for regulators to ensure that utilities bear financial consequences from failures to comply with regulatory standards, regulators should also be mindful of the cumulative effect of their ratemaking decisions, in order to ensure that the utility has the financial resources to carry out service obligations in the future.

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[241] OIR, p. 11.

[242] OIR, p. 11.

The objective of Ms. Tierney's ratemaking principles is to align the utility's financial objectives with its service obligations and to provide the utility with the resources to perform its service obligations (including safety) in a financially healthy way. By aligning a utility's interest with its obligations, the Commission can eliminate disincentives that may create a tension within the utility between its financial performance and its achievement of existing and improved service quality standards. This principle rests on long-standing regulatory foundations,[243] and should apply when the utility is maintaining compliance with existing regulations or is making new investments and changes in operating practices to comply with new regulatory requirements.

Ms. Tierney also provides guidance on how the Commission should coordinate the pending pipeline-related Orders Instituting Investigation ("OII") with the PSEP ratemaking determination in this proceeding. If, as a result of investigations into and assessments of past performance, the Commission were to find that a utility failed to satisfy prior requirements, Ms. Tierney recommends that the Commission impose any penalties, fines or disallowances through ratemaking mechanisms that do not undermine appropriate going-forward ratemaking incentives.

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[243] The "Hope" and "Bluefield" standard reflects this principle and supports ratemaking that ensures that the utility has enough revenue to cover operating expenses (including servicing debt and equity requirements commensurate with other enterprises with comparable risks):

> "Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. . . . A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923);
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> "[T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

The Commission should avoid administering penalties, fines or cost disallowances in a way that results in an on-going financial burden to the utility such that the form of the penalty (especially when combined with its size) becomes a barrier to enabling the utility to make the changes in operations and systems needed to raise its performance and achieve compliance with past or new safety requirements.

By imposing any such penalties, fines, or cost disallowances through one-time ratemaking mechanisms, regulators can create the expectation that failures to achieve regulatory standards may have financial consequences and serve as an important deterrent to non-compliance with health, safety, environmental and other regulations.

PG&E's Senior Vice President of Regulatory Relations frames this critical policy issue in his rebuttal testimony:

> One of the Commission's objectives in the proceeding is to align safety and ratemaking policies so that in the future the ratemaking process will put the proper focus on and encourage safety investments. The broad disallowance recommendations of parties in this case are inconsistent with the Commission's objective. DRA and TURN are encouraging the Commission to require PG&E to push ahead with over $2 billion in new expenses and investment to comply with a new safety standard and would provide very limited or no cost recovery for these efforts. Several parties encourage the Commission to adopt a reduced rate of return on new safety capital investments. These recommendations do not encourage PG&E to make safety investments or facilitate the financing of those investments. They do the opposite. Under the intervenor proposals, investments in safety to meet a new regulatory requirement would earn a lower return than other non-safety investments. Under their disallowance recommendation, cost of service ratemaking would be suspended for new safety improvements. This turns the regulatory compact on its head and is the wrong direction for the Commission to take as it rethinks the way the ratemaking process treats safety issues.[244]

It is important to distinguish steps taken to hold regulated companies accountable for past actions and ratemaking that supports forward-looking compliance to meet new standards. When

[244] Ex. 21, PG&E Rebuttal, p. 1-29, line 18—p. 1-30, line 2.

changes in policy require the utility to incur significant new costs to achieve policy objectives and compliance with new standards, and where there was no reasonable basis to conclude that existing rates included such investments, the utility should be provided with an opportunity to recover these costs in rates in a timely fashion.

Finally, Ms. Tierney recommends that the Commission should be wary of establishing rates which create such an untenable financial outcome that the utility is fundamentally handicapped from performing its service obligations. A utility in sound financial health may be better positioned to achieve the many broad public policy objectives, including, but not limited to, increasing the safety of its system for customers, workers and communities. Given the capital-intensive nature of utility systems, investments are particularly important to achieving these public benefits. The Commission should support ratemaking that enables the utility to attract the capital needed to make these investments and maintain or improve its systems and to do so at reasonable cost.

B. PG&E's Shareholder-Customer Cost Sharing Proposal Reasonably Establishes The PSEP Costs That Should Be Eligible For Recovery From Customers And Which Should Be Ineligible For Recovery

The Commission ordered PG&E to include a shareholder-customer cost sharing proposal in its PSEP filing.[245] There are two elements to PG&E's cost sharing proposal. First, PG&E has proposed that the Commission adopt two "eligibility" principles that define which PSEP costs are eligible for recovery in rates and which PSEP costs are ineligible for rate recovery. The eligibility principles examine 1) whether the costs of PSEP work are incremental to existing GT&S rates and 2) whether the PSEP work is in response to a new gas pipeline safety requirement or required to comply with pre-existing regulatory requirements. Second, PG&E has proposed to forgo cost recovery of its 2011 costs for PSEP work that would otherwise be recoverable under the "eligibility" principles described above. This is proposed as a minimum shareholder contribution toward any disallowances, remedial actions or penalties that may be

[245] D.11-06-017, Ordering Paragraph 10, p. 32.

determined by the Commission to be appropriate in the Gas Recordkeeping OII, the San Bruno OII and the Class Location OII (collectively referred to as the "OIIs").[246]

1. PG&E's First Eligibility Principle Reasonably Ensures That There Is No "Double Recovery" Of PSEP Costs

PG&E has proposed that the Commission adopt two principles that define which PSEP costs are eligible for recovery in rates and which PSEP costs are ineligible for rate recovery. The first principle is:

> 1. Incremental costs associated with complying with the new regulatory gas transmission safety standard adopted by the Commission in Decision 11-06-017 or as part of a new safety program proposed in response to that decision should be recoverable in rates. [247]

Under this eligibility principle, PSEP work must be incremental to the forecasted work in PG&E's current GT&S rate case, which covers the period 2011 to 2014. Under this principle, pipe replacement, ILI retrofitting and inspections, hydrotesting and transmission asset management technology projects that were forecast in the GT&S Rate Case, if any, cannot be "recovered a second time" in the PSEP.[248] The question whether PSEP costs are incremental requires a review of the projects and forecasts embedded in current GT&S rates adopted by the Commission in D.11-04-031.

No party has identified any double counting between the PSEP rate request and the 2011 GT&S rate case. PG&E witness Marre testified that "PG&E's cost recovery request is incremental to existing rate case decisions. . . . None of these costs were included in PG&E's most recent GRC (A.09-12-020) or GT&S Rate Case (A.09-09-013)."[249] DRA witness Sabino testified that she was not able to identify any projects or costs included in the PSEP that had also

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[246] Ex. 21, PG&E Rebuttal, p. 1-17, lines 3-10.

[247] Ex. 21, PG&E Rebuttal, p. 1-11, lines 15-18.

[248] Ex. 21, PG&E Rebuttal, p. 1-11, lines 22-27.

[249] Ex 2, PG&E Direct, p. 8-6, line 9—p. 8-7, line 2.

been requested in the current GT&S rate case.[250]

PG&E has demonstrated that there is no double counting in the PSEP:

- Pipe Modernization: PG&E witness Hogenson testified that he verified that all Pipeline Modernization work is incremental to Gas Accord V work and he specifically excluded pipeline replacement and other work that was authorized by Gas Accord V.[251] PG&E's GT&S rate case for 2011 to 2014 included a detailed break-out of its cost estimate for work under the Transmission Integrity Management Program ("TIMP"). PG&E did not include any hydrotesting in its forecast for the time period 2011 to 2014.[252] Northern California Indicated Producers ("NCIP") witness Beach concludes—based on PG&E's responses to his discovery requests—that the projects proposed in PG&E's PSEP do not duplicate projects to be carried out in PG&E's TIMP under the currently-funded rate case.[253] DRA conducted discovery on the question of whether the PSEP costs are incremental. This review confirmed that nine pipeline replacement projects had been removed from the PSEP work scope due to duplication with projects in the GT&S rate case.[254] DRA stated that it was "easy" to identify individual capital projects in the current GT&S rate case to compare with the PSEP.[255] DRA also did not find any funding in any prior GT&S rate cases for hydrostatic testing work that would be performed in the PSEP.[256] DRA also

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[250] Tr. (Sabino), p. 2307, line 2—p. 2309, line13.

[251] Ex. 2, PG&E Direct, p. 3-38, line 16—p. 3-39, line 2; see also discussion of 2011 GT&S rate case revenue requirements, Ex. 2, PG&E Direct, pp. 2-20—2-21.

[252] Ex. 2, PG&E Direct, p. 2-18, Table 2-6.

[253] "I have asked PG&E in discovery about a number of [PSEP] projects that appear to overlap with TIMP projects. To date, PG&E's responses appear to show that there is no duplication between [PSEP] and TIMP." Ex. 123, NCIP Direct, p. 10, lines 3-6.

[254] Ex. 149, DRA Direct (Sabino), p. 30, lines 1-12. A tenth capital project remained in the PSEP because it was forecast to go into service after the Gas Accord V rate case period and is not covered by existing rates. Id.

[255] Ex. 149, DRA Direct (Sabino), p. 30, lines 13-20.

[256] Ex 149, DRA Direct (Sabino), p. 31, line 15—p. 32, line 8.

reviewed the in-line inspection and retrofit work proposed in the PSEP and did not find any duplication with prior rate cases.[257]

- Valve Automation: The Valve Automation Program is a new program to install automatic shut-off valves on all large diameter, high pressure, gas transmission pipelines in Class 3 HCA and all gas transmission lines in Class 4 areas.[258] PG&E has not included a valve automation program in its prior GT&S rate cases and typically only considered valve automation in connection with the installation of new large gas transmission lines, such as Line 401. DRA did not find any duplication for the Valve Automation Program based on a review of valve-related projects from 2000 to 2010.[259]
- MAOP Validation: The cost to validate the MAOP of PG&E's gas transmission lines is incremental to Gas Accord V[260] and the 2011 GRC.[261] PG&E is performing MAOP validation to comply with the Commission's order in Decision 11-06-017 to compile "traceable, verifiable and complete records readily available."[262] This is a new regulatory requirement that could not have been and was not anticipated at the time rate forecasts were developed and settled in the 2011 GT&S rate case.
- GTAM: As discussed in Section IV.D, the entire GTAM forecast is incremental to PG&E's 2011 GRC and 2011 GT&S rate case.[263] In fact, the *entire expense budget* for all gas transmission operations and maintenance in Gas Accord V is $105 million, and would be insufficient to fund the GTAM Project cost of $124

[257] Ex 149, DRA Direct (Sabino), p. 32, lines 9-17.

[258] Ex. 2, PG&E Direct, p. 4-1—p. 4-4.

[259] Ex 149, DRA Direct (Sabino), p. 33, lines 18-23.

[260] Ex. 2, PG&E Direct, p. 5-14, lines 2-4.

[261] Ex. 21, PG&E Rebuttal, p. 11-3, lines 9-21.

[262] Ex. 21, PG&E Rebuttal, p. 11-4, line 1—p. 11-5, line 20.

[263] Ex. 2, PG&E Direct, p. 5-30, line 6—p. 5-31, line 18; Ex. 21, PG&E Rebuttal, p. 11-1, line 20—p. 11-3, line 21.

million.[264]

- Interim Safety Enhancements: For the interim safety enhancement measures, DRA did not find any duplication with the current GT&S rate case, although it did express some concerns about whether PG&E's request for four new gas planning engineers was adequately supported.[265] As discussed in Section V.A.1, PG&E provided extensive justification for the four new planning engineers in its rebuttal testimony in order to complete new, on-going PSEP work including analyzing the feasibility of new interim pressure reductions, managing the increased number of system clearances due to increased hydrotesting, analyzing the impacts on customer supply and demand resulting from valve automation and pipeline replacements, and managing the on-going pressure reductions.[266]

2. PG&E's Second Eligibility Principle Reasonably Ensures That There Is No Cost Recovery For PSEP Work That Would Have Been Required If D.11-06-017 Had Never Been Issued

PG&E's second "eligibility" principle is:

> 2. To the extent an activity must be undertaken in the PSEP to comply with preexisting regulatory requirements, PG&E will not seek cost recovery for such activities in the PSEP.

This eligibility principle excludes cost recovery for PSEP work that otherwise would have been required by a pre-existing regulatory standard. It is an objective test that can be applied on an after the fact basis. Under this principle, it is fair to ask the question "would PG&E have been obligated to do the work if Decision 11-06-017 had never been issued?" If the answer is yes, PG&E is doing the work under the PSEP to come into compliance with a pre-existing regulatory requirement and the funding provided under existing GT&S rates should cover the costs of the work since PG&E would have been required to comply with pre-existing regulatory

[264] Id.

[265] Ex 149, DRA Direct (Sabino), p. 33, line 21—p. 34, line 6. The cost justification for these 4 FTEs is discussed in section V.A of this brief.

[266] Ex. 21, PG&E Rebuttal, p.12-4, line 15—p. 12-6, line 23.

requirements even if Decision 11-06-017 had never been issued.[267] On the other hand, if PG&E was not obligated to pursue the work before the issuance of Decision 11-06-017, then the work is a new compliance obligation stemming from Decision 11-06-017 and customers should fund the costs of complying with the new safety requirement.[268]

In application of this second eligibility principle, PG&E has subtracted from its PSEP request (1) the costs of hydrotesting post-1970 transmission lines where PG&E lacks complete documentation of a strength test ($11.8 million)[269] and (2) the costs of post-1970 pipeline replacements ($9.8 million). [270] This is reasonable because PG&E was obligated starting in 1970 to conduct hydrostatic tests on newly installed pipelines under 49 CFR Part 192 and to retain records of such tests. In addition, PG&E removed the costs of MAOP Validation for post 1970s pipeline components ($85.9 million)[271] and PG&E agreed in its comments on the CPSD Report that shareholders should bear responsibility for hydrotesting under the PSEP if PG&E lacks records of hydrotests that were required starting in 1961 under GO 112 ($32 to $48 million in 2012-2014).[272] Under eligibility principle number 2, PG&E has proposed to have its shareholders fund approximately $139.5 million to $155.5 million in PSEP costs to be incurred in the 2011 to 2014 period.

The shareholder allocation described above is a forecast. PG&E will exclude from PSEP cost recovery the actual costs of these projects. In addition, to the extent that PG&E determines that additional PSEP costs should be excluded based upon application of eligibility principle number 2, PG&E will exclude such costs. PG&E witness Bottorff testified that PG&E

[267] In reality, these costs are shareholder funded since the expenditures to cover such work are in excess of the authorized GT&S revenue requirement.

[268] Ex. 21, PG&E Rebuttal, p. 1-11, line 31—p. 1-13, line 10.

[269] Ex. 2, PG&E Direct, p. 1-14, Table 1-1.

[270] Ex. 2, PG&E Direct, p. 3-66, line 8. Under PG&E's proposal, it would not seek recovery for the revenue requirement associated with these capital expenditures for the 2011-2014 period.

[271] Ex. 2, PG&E Direct, p. 1-14, Table 1-1.

[272] Ex. 21, PG&E Rebuttal, p. 1-17, line 27—p. 1-18, line 4; PG&E's Response to Technical Report of the Consumer Protection and Safety Division Regarding PG&E's Pipeline Safety Enhancement Plan, dated January 13, 2012, pp. 1-4.

determined after filing the PSEP that certain pipe segments will be hydrotested as part of its 2012 Transmission Integrity Management Program work plan.[273] Since this hydrotesting will be completed to meet a pre-existing regulatory requirement, the costs of such TIMP hydrotests will be excluded from PSEP cost recovery and this reduction in costs will be passed on to customers as part of the true-up of forecasted expense to actual expense for the hydrotesting program. On-going implementation of eligibility principle number 2 will be addressed in PG&E's semi-annual reports and will be subject to Commission review, verification and audit of its proposed PSEP balancing accounts.

3. PG&E Has Also Proposed To Forgo Recovery Of All 2011 PSEP Costs As A Minimum Shareholder Disallowance To Address The Unique Circumstances Associated With The OIIs

In Decision 11-06-017, the Commission ordered that PG&E's PSEP must include a cost-sharing proposal between ratepayers and shareholders.[274] This requirement applies to PG&E only; the only explanation for treating PG&E differently than the other respondent utilities is a reference to the Order Instituting Rulemaking 11-02-019, issued February 24, 2011, where the Commission stated:

> The unique circumstances of PG&E's pipeline records and pipeline testing program for its pre-1970 pipeline may require extraordinary safety investments. . . . The extraordinary safety investments required for PG&E's gas pipeline system and the unique circumstances of the costs of replacing the San Bruno line are situations where this Commission may use its ratemaking authority to, for example, reduce PG&E's rate of return on specific plant investments or impose a cost sharing requirement on shareholders. We will consider these, and other ratemaking mechanisms, in this proceeding.[275]

The decision further states that the Commission intends "to take official notice of the record in other proceedings, including the investigation of PG&E's gas system record-keeping (R.11-02-

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[273] Tr. (Bottorff), p. 944, line 7—p. 945, line 11.

[274] D.11-06-017, p. 22; Ordering Paragraph 10, p. 32.

[275] OIR 11-02-019, pp. 11-12.

016), in our ratemaking determination." [276] Based upon the MAOP validation submissions and the PSEPs filed by other gas utilities in California, it has become apparent since the issuance of the OIR that PG&E's historic record keeping and pipeline testing programs were not unique at all. The PG&E PSEP and the Sempra utilities PSEP are comparable in scope, work activity, cost and bill impacts on customers.[277]

Under the Public Utilities Code, the Commission's primary purpose "is to insure the public adequate service at reasonable rates without discrimination . . ."[278] A fundamental legal question is whether adopting a cost-sharing mechanism for PG&E that is different than the ratemaking mechanisms applicable to the other gas utilities satisfies this requirement.

One area where the circumstances for PG&E differ from the other gas utilities is that the Commission has instituted the OIIs to investigate the San Bruno accident and PG&E's historic gas transmission operations and recordkeeping. While it is still early in those investigations and PG&E has not yet had an opportunity to submit its response to the allegations, the Commission will need to address the linkage between the OIIs and the ratemaking determination in this proceeding. Under the second element of PG&E's cost sharing proposal, PG&E has proposed to forgo cost recovery of its 2011 costs for PSEP work that would otherwise be recoverable under the "eligibility" principles described above. This proposal takes into account the PG&E gas record keeping OII, the San Bruno OII and the Class Location OII and is proposed as a minimum shareholder contribution toward any fines, disallowances, remedial actions or penalties that may be determined by the Commission to be appropriate in the OIIs.[279]

PG&E has proposed this mechanism to establish a linkage between the outcomes of the

[276] D.11-06-017, p. 23.

[277] For example, Southern California Gas Company identified 385 miles of transmission pipeline in category 4 for which it did not have sufficient documentation of a strength test to at least 1.25 times MAOP. Ex. 21, PG&E Rebuttal, p. 10-7, lines 13-15.

[278] *Pac. Tel. and Tel. Co. v. Pub. Util. Comm'n*, 34 Cal.2d 822, 826 (1950); *Pac. Tel. and Tel. Co. v. Pub. Util. Comm'n*, 62 Cal.2d 634, 647 (1965); *City and County of San Francisco v. Pub. Util. Comm'n*, 6 Cal.3d 119, 126 (1971).

[279] Ex. 21, PG&E Rebuttal, p. 1-17, lines 3-10.

OIIs and the PSEP in order to establish a process so that any potential penalties, disallowances or restitution that the Commission may order in the OIIs can be applied as a reduction to PSEP cost recovery that may otherwise be charged to customers. This provides an alternative to submitting fines to the state general fund. PG&E witness Bottorff stated PG&E "felt it was appropriate [for the Commission] to take note of the fact that these [2011 PSEP costs] were dollars that would have been eligible for recovery. Rather than seek recovery of them here, we . . . propose that they be recognized as an offset to any fine or restitution that might [result from the OIIs]." PG&E developed this proposal as a way for the Commission to recognize the costs PG&E incurred in 2011 that would otherwise have been eligible for recovery under its "eligibility" principles discussed above. [280] Mr. Bottorff clarified at the hearings that PG&E is not proposing to offset "fines" payable to the general fund under this approach, if any such fines are imposed. However, to the extent the Commission chooses to order some type of restitution or disallowance in the OIIs, PG&E asks that the Commission take into account the 2011 costs that its shareholders have already incurred in this proceeding and consider these amounts a credit toward such restitution or disallowance.[281]

Under PG&E's proposal the <u>minimum</u> amount of this adjustment would be a reduction in revenue requirement equal to PG&E's actual 2011 costs, which will be at least $332 million, given PG&E's $222 million forecast [282] for 2011 PSEP work and the $110 million cost overrun on hydro testing in 2011.[283] Under its proposal, PG&E would make a compliance filing to adjust PSEP rates as applicable to incorporate any cost disallowances the Commission adopts in the OIIs.

PG&E also notes that its shareholders have already borne substantial costs for other gas

[280] Tr. (Bottorff), p. 948, line 6—p. 949, line 24.

[281] Tr. (Bottorff), p. 952, lines 3-25.

[282] Ex. 21, PG&E Rebuttal, p. 1-14, Table 1-1, lines 2-3. The $222.1 million shown on lines 2-3 are the forecasts for PSEP work that would be eligible for cost recovery under PG&E's "eligibility" principles discussed above.

[283] The actual cost of the hydrostatic testing program was $231 million in 2011. Ex. 21, PG&E Rebuttal, p. 4-2, lines 1-23. PG&E's forecast for 2011 hydrostatic testing was $121 million. Ex. 2, PG&E Direct, p. 3-65, Table 3-5, line 2.

pipeline-related activities following the San Bruno accident. When the PSEP was submitted in August, 2011, PG&E forecasted that it would incur $215 million above authorized revenue requirements in 2010 and 2011 for additional activities, such as gathering gas records, conducting additional leak surveys, emergency response costs at San Bruno, customer outreach, and supporting the NTSB, CPUC and IRP investigations.[284] PG&E's shareholders are now likely to spend $1.6 to $1.7 billion more than authorized in existing rates.[285] This approaches PG&E's net investment in its pipeline business that has been built up over decades.[286]

C. It Is Reasonable Under Commission Criteria To Authorize PG&E To Change Rates During The Gas Accord V Period Because The Measures To Implement New Safety Requirements In D.11-06-017 Could Not Have Been Forecast By PG&E In The GT&S Rate Case And Are Not Part Of "Normal Day To Day" Utility Operations

DRA takes the position that under the general concept of forecast test year ratemaking, GT&S revenues were intended to fund all the costs of providing service and operating the utility system during the period covered by the 2011 GT&S Rate Case and, for this reason, PG&E should not recover PSEP costs during the GT&S Rate Case period 2011-2014.[287] It is correct that the general principle behind traditional test year forecast ratemaking is to authorize a rate level based upon a reasonable forecast and that once rates are set the utility has discretion to spend its funds in the most cost effective manner to provide safe and reliable service. However, there have been many examples where the Commission has authorized incremental rate recovery for new projects or programs during a rate case period.[288] For example, in D.10-06-048, the

[284] Ex. 2, PG&E Direct, p. 1-14, Table 1-1, line 7 and footnote (a).

[285] This estimate assumes: 1) a fine of at least $200 million; 2) annual pipeline related costs above authorized revenue requirements of $550 million in 2011 and 2012; and 3) $400 million of shareholder funded amounts above authorized revenue requirements to be spent in 2012-13 across all business operations. Ex. 21, PG&E Rebuttal, p. 1-17, lines 12-24.

[286] Ex. 21, PG&E Rebuttal, p. 1-17, lines 22-24; footnote 1.

[287] Ex. 143, DRA Direct (Pocta), pp. 5-10.

[288] See D.06-07-027 (CPUC authorized PG&E to deploy a new Advanced Metering Infrastructure ("AMI") and recover incremental revenue requirements associated with the program during an existing rate case cycle); D. 05-11-026 (CPUC authorized PG&E to proceed with and recover in rates the costs of new steam generators at the Diablo Canyon Power Plant ("DCPP"). The DCPP steam generator application was filed and approved during a rate case period); D.10-06-048 (CPUC authorized PG&E to proceed with the "Cornerstone" electricity reliability

"Cornerstone" decision, the Commission approved a significant new electric reliability program and resulting rate change to fund the program during an existing GRC cycle.[289] The takeaway here is that the Commission evaluates utility applications on a case-by-case basis to determine if the proposed request for incremental cost recovery falls within the "normal day to day operations" that are covered by a GRC decision or if there are features that distinguish the rate recovery request from the normal process.

In Decision 96-12-066 the Commission denied a PG&E request for an attrition adjustment to its base 1996 GRC rates.[290] PG&E asserted in the application that it was experiencing higher than forecast costs associated with tree trimming, call center activities and meter reading and it asked the Commission to authorize a future year attrition rate adjustment to reflect its higher costs. The Commission determined that these cost categories were covered by the rate case plan and that reopening the rate case was not warranted. The Commission ruled that tree trimming, meter reading and call center activities all were within the normal activities that are covered by a general rate case and that it is not an "extraordinary circumstance" for a utility to determine "it should spend more than it previously planned to spend" for normal maintenance activities.[291]

In the decision, the Commission set forth four factors that guide whether "extraordinary circumstances" warrant reopening of the forecast rates set in a general rate case. These factors are:

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program outside the normal general rate case process.)

[289] In D.10-06-048, the Commission considered and approved an electric distribution reliability program proposed by PG&E outside the normal GRC process, although the scope of the program was reduced by the Commission. The Commission recognized in the Cornerstone decision that it is appropriate to approve new reliability programs and to change rates to fund the program during an existing GRC cycle. The Commission stated "[i]n considering Cornerstone separately now rather than deferring it to the 2011 GRC, we indicated our overall concern with respect to electric distribution reliability. Since Cornerstone was designed to significantly improve that reliability, we determined it was preferable to address the request sooner rather than later." (p. 19)

[290] *Re Pac. Gas and Elec. Co.*, D.96-12-066, 69 CPUC 2d 691 (1996).

[291] 69 CPUC2d at 696.

1. Does the request involve the "day-to-day cost of operating a safe and reliable electric utility business?"[292]
2. Does the request fail the "test of fundamental fairness" by selecting "a handful of accounts where it asserts additional revenues are needed?"[293]
3. Is the request a result of "inadequacies [in] its earlier planning practices?"[294] In other words, could this cost have reasonably been forecast in the general rate case?
4. Does the request require the Commission to dedicate its resources to provide a "second bite at the apple" by relitigating issues already addressed in the GRC?[295]

All four factors support cost recovery here. The PSEP scope of work is required to comply with a significant new safety program adopted by the Commission in Decision 11-06-017. This decision was adopted after approval of the GT&S Rate Case settlement. D.11-06-017 requires gas utilities to undertake new activities that are significantly above and beyond pre-existing normal "day to day gas operations activities" covered in the GT&S Rate Case. For example, PG&E is now required to pressure test or replace every transmission pipeline segment on its system that was "grandfathered" under existing Federal regulations.[296] The Commission expressly recognized this in its order: "Natural gas transmission pipelines placed in service prior to 1970 were not required to be pressure tested, and were exempted from then-new federal regulations requiring such tests."[297] "We conclude, therefore, that all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety. Historic exemptions must come to an end with an orderly and cost-conscious implementation plan."[298] PG&E was not required or expected to achieve this scope of work prior to issuance of Decision 11-06-017. The same is true with

[292] 69 CPUC2d at 695.
[293] 69 CPUC2d at 695.
[294] 69 CPUC2d at 695.
[295] 69 CPUC2d at 695-696.
[296] D.11-06-017, pp. 19-20; Ordering Paragraphs 4 – 10.
[297] D.11-06-017, p. 27, Finding of Fact 6.
[298] D.11-06-017, p. 18.

respect to the Commission's order to conduct MAOP validation[299] and to have "traceable, verifiable, and complete records readily available."[300] These industry changing new compliance requirements could not have been forecast by PG&E at the time the GT&S Rate Case settlement was submitted to the Commission. PG&E did not fail to include the cost of compliance with Decision 11-06-017 in the GT&S Rate Case "due to inadequacies of its forecast." PG&E has not selected a handful of accounts to seek additional revenues. Nor is it seeking a "second bite of the apple" at issues considered in the GT&S Rate Case. Rather, PG&E's PSEP proposal represents a new program mandated by Decision 11-06-017.

The Commission in Decision 06-07-027 authorized PG&E to deploy a new Advanced Metering Infrastructure ("AMI") and recover incremental revenue requirements associated with the program during an existing rate case cycle. The AMI decision is analogous to the PSEP. PG&E's application for approval of the AMI program was filed as a result of a Commission rulemaking (R.02-06-001) to evaluate demand response alternatives and represented a significant, game changing enhancement in the way electric utilities provide electric service to their customers. The AMI application arose from a policy direction that was first expressed by the Commission through an OIR and PG&E's plan for AMI deployment was evaluated based upon whether the utility proposal met the functionality criteria that had been pre-established by an Assigned Commissioner Ruling. The AMI application also required a significant capital investment, estimated to be $1.6 billion at the time of approval.[301] The Commission authorized PG&E to proceed with the AMI investments and authorized a revenue requirement outside of the normal GRC process, with the expectation that later-incurred AMI costs would be folded into a future GRC once the costs of the program were more certain.[302] The PSEP case similarly arose from a Commission OIR which ordered fundamental changes to gas safety regulatory

[299] D.11-06-017, Ordering Paragraph 1; Conclusion of Law 1.

[300] D.11-06-017, pp. 19-20; See also Ex. 21, PG&E Rebuttal, p. 11-4.

[301] D.06-07-027, pp. 2-3.

[302] D.06-07-027, p. 50.

requirements applicable to all gas utilities in California. The Commission ordered PG&E and the other gas utilities to make the PSEP filings, specified what the filings would include, ordered that PSEP work "must reflect a timeline for completion that is as soon as practicable," and ordered the utilities to include a rate proposal for PSEP work. The scope and nature of the changed circumstances surrounding the PSEP filings is very similar to the AMI program, which was expressly authorized for implementation and rate recovery as an exception to the normal general rate case "test year ratemaking" process.

D. The Gas Accord V Settlement Specifically Authorizes PG&E To Change Rates In Order To Comply With Commission Orders In Other Proceedings

DRA argues that rate recovery for the PSEP is barred under the terms and conditions of the Gas Accord V Settlement Agreement.[303] Section 12.1 of the Gas Accord V Settlement Agreement addresses rate changes during the GT&S Rate Case period:

> 12.1 Rate Certainty
>
> The rates specified in this Settlement Agreement are not subject to adjustment during the Settlement Period except as provided herein, or as agreed to by the Settlement Parties and approved by the Commission. In particular, the demand forecast underlying the Settlement backbone rates assumes that none of the G-XF contracts except the NCPA contract has on-system delivery rights. If during the Settlement Period any off-system G-XF shippers receive on-system delivery rights, the demand forecast and backbone rates may need to be adjusted to account for displacement of other on-system services by these G-XF shippers.
>
> ***Nothing in this Settlement Agreement shall prevent PG&E from making adjustments to services, capacity assignments, cost allocations, rates or the like in order to comply with Commission orders in other proceedings.*** No Settlement Party shall make any proposal that would conflict with or alter any term of this Settlement Agreement, and the Settlement Parties shall not support proposals of others that would do the same. (Emphasis added)

The critical sentence here is that "Nothing in this Settlement Agreement shall prevent

[303] Ex. 143, DRA Direct (Pocta), pp. 10-12.

PG&E from making adjustment to…rates…in order to comply with Commission orders in other proceedings."[304] In this case, Decision 11-06-017 ordered PG&E to submit the PSEP and to propose rates associated with the costs of implementation of the new safety standards adopted in the decision. PG&E submitted the PSEP filing to comply with the Commission's order in another proceeding. The PSEP filing thus fits within the authorization to take actions in compliance with Commission orders in Section 12.1.

E. There Was No Regulatory Requirement To Conduct Hydrostatic Pressure Tests On Transmission Pipelines Or To Retain Records Of Such Tests Prior To Adoption Of GO 112 In 1961. The Existence Of Prior Voluntary Industry Testing Guidelines Does Not Establish A Reasonable Evidentiary Basis For Disallowing All PSEP Costs For Hydrotests On Pre-1961 Pipelines

As discussed above, under eligibility principle 2, PG&E has proposed as part of its customer/shareholder sharing proposal that hydrostatic testing costs on transmission pipelines installed after 1961 where PG&E lacks adequate documentation of a past strength test would not be eligible for cost recovery in the PSEP because PG&E was required under GO 112 and 1970 federal regulations to have conducted hydrotests on these pipelines and retained records of such tests. The issue, then, for the Commission to address is whether it is reasonable for PG&E to recover in rates the PSEP costs for hydrotests of pipelines installed prior to 1961, when there was no regulatory requirement to conduct such tests or maintain records. DRA and TURN advance two arguments to suggest that hydrotesting costs on pre-1961 transmission pipelines should be disallowed. Their first argument is that there were voluntary industry guidelines for hydrotesting prior to 1961 and any instances of PG&E's failure to follow these guidelines—dating to 1935—was *per se* imprudent. DRA and TURN's second argument is that PG&E should have pursued hydrotesting under the Transmission Integrity Management Program, which went into effect in 2004.

Neither of these arguments justifies disallowance of hundreds of millions of dollars of costs for hydrotests to satisfy a new Commission-imposed safety requirement in Decision 11-06-

[304] Ex. 21, PG&E Rebuttal, p. 1-20, lines 24-27.

017 on previously "grandfathered" transmission pipelines. In Decision 11-06-017, the Commission recognized that "[n]atural gas transmission pipelines placed in service prior to 1970 were [not] required to be pressure tested, and were exempted from then-new federal regulations requiring such tests."[305]

1. Pre-1970 Gas Transmission Pipelines Are Subject To A Grandfather Clause In The Federal Code That Exempts Such Pipelines From Hydrotesting Regulations

Almost two-thirds of the nation's gas transmission pipelines were constructed prior to the adoption of federal pipeline safety laws and regulations in 1970.[306] The effort to develop industry standards for pipeline design, material specifications, and records retention started in the 1930's and evolved, becoming more prescriptive over time. The concept of pipeline safety is not new, but it has changed significantly over time as the infrastructure that is already in the ground has aged.[307] As the industry moved from a model of voluntary industry-developed guidelines to adoption of federal regulations, the question of how to treat pipelines installed prior to adoption of the pipeline safety regulations was considered and addressed. Part 192 of the Code of Federal Regulations was promulgated in 1970 and adopted specific accommodations for vintage pipe. A "grandfather clause" was created as part of the 1970 federal code, 49 CFR 192.619(c), which specified that if appropriate records of a hydrotest could not be produced to validate the MAOP of a transmission line segment, the gas utility could use the historic documented operating pressure over the previous five years.[308] The grandfather clause was adopted because the Department of Transportation ("DOT") recognized that pressure tests on pre-1970 pipelines may not have been conducted or the records of such test may not be available.[309] Pre-1970 transmission pipelines were grandfathered under CFR Part 192 "as acknowledgement that

[305] D.11-06-017, p. 27, Finding of Fact 6.

[306] Ex. 2, PG&E Direct, p. 2-8, lines 5-7; Ex. 21, PG&E Rebuttal, p. 10-9, lines 1-5.

[307] Ex. 21, PG&E Rebuttal, p. 10-3, line 21—p. 10-4, line 24.

[308] Ex. 2, PG&E Direct, p. 2-10, lines 17-31; Ex. 21, PG&E Rebuttal, p. 10-4, lines 25-30.

[309] Ex. 21, PG&E Rebuttal, p. 10-4, line 25—p. 10-5, line 22.

operators may not have construction, design and testing records sufficient to validate MAOP based upon the new standards." [310] In the explanatory statement published by DOT in the Federal Register that accompanied the Part 192 regulations, DOT stated:

> *Retroactive effect on existing pipelines*. Many comments related to the effect of these regulations on existing pipelines. They expressed concern that existing pipelines would not meet the design, construction, and testing requirements of the new regulations and would therefore have to be replaced or otherwise modified in order to comply. There is no basis for this concern and the prospective effect of Part 192 is made clear in section 192.13.[311]

The DOT concluded that not applying the Part 192 design, testing and construction requirements retroactively would not compromise safety because such pipelines would be operated subject to the five year historic operating maximums.[312]

Similarly, when the CPUC adopted GO 112, effective July 12, 1961, the Commission acknowledged that there had been no prior pipeline safety regulation in California. In adopting regulations where there previously had been none, the Commission made accommodations for existing pipelines by deciding that the GO 112 rules would only have limited retroactive application for existing pipelines. Section 104.3 of GO 112 stated:

> It is not intended that these rules be applied retroactively to existing installations insofar as design, fabrication, installation, established operating pressure, and testing are concerned. It is intended however, that the provisions of these rules shall be applicable to the operation, maintenance and up-rating of existing installations.

In other words, the Commission did not intend to retroactively apply the design, construction, operating pressure and pressure testing/qualifying decisions made for pipeline facilities installed prior to the GO 112 July 1, 1961 effective date.[313]

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[310] Ex. 21, PG&E Rebuttal, p. 10-9, lines 5-8.

[311] Ex. 52, 5 Fed. Reg. 13248, 13250 (Aug. 19, 1970) .

[312] *Id.*, at 13248.

[313] Ex. 2, PG&E Direct, p. 2-9, lines 3-24.

Both the CPUC's safety regulations in GO 112 and the federal regulations in Part 192 did not require gas utilities to hydrotest (or retain records of hydrotests) gas transmission pipelines installed prior to the effective date of the regulation. The decision by the Commission in 1961 and the DOT in 1970 to apply the new pipeline safety regulations on a prospective basis was not modified until the Commission, in Decision 11-06-017 ordered the gas utilities to pressure test or replace all gas pipelines that lacked complete records of a prior hydrostatic pressure test.

In the aftermath of the San Bruno accident it is natural to second guess these decisions to apply hydrotesting standards on a prospective basis. Clearly, state and national policy is evolving to eliminate the historic exemptions and it appears that all gas utilities will need to go through the process that PG&E is in the midst of to compile, review and address gaps in historic recordkeeping and where appropriate, hydrotest vintage pipe to establish MAOP. Even if one believes today that grandfathering was not advisable, that does not mean that a failure by gas utilities to operate in the 1930's, 1940's and 1950's to today's standards was in any way unreasonable. It was not unreasonable for a utility to rely on grandfathering to determine MAOP in the 1960s and 1970s since the regulations in place at that time expressly authorized this practice.

2. Industry Guidelines On Pre-1970 Hydro Testing and Record Retention Of Such Tests Were Voluntary. There Is No Evidentiary Basis To Conclude That Failure To Implement Such Voluntary Guidelines Was An Imprudent Act

In evaluating whether PG&E's historic operating practices were "reasonable and prudent" the Commission will review if:

> at a particular time any of the practices, methods, and acts engaged in by a utility follows the exercise of reasonable judgment in light of facts known or which should have been known at the time the decision was made. The act or decision is expected by the utility to accomplish the desired result at the lowest reasonable cost consistent with good utility practices. Good utility practices are based upon cost effectiveness, reliability, safety, and expedition.

> A "reasonable and prudent" act is not limited to the optimum practice, method, or act to the exclusion of all others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with the utility system needs, the interest of the ratepayers and the requirements of governmental agencies of competent jurisdiction.[314]

DRA takes the position that the costs of all hydrostatic testing done under the PSEP on pipeline installed in 1935 or later should be fully disallowed on the grounds that PG&E should have implemented a 1935 American Standards Association ("ASA") guideline, which DRA's own summary concedes does not require hydrotesting on most gas transmission pipelines until the late 1950s. There are a number of flaws with DRA's argument.

First, the 1935 ASA and each of its successors were voluntary advisory guidelines. There was no regulatory requirement to implement the guidelines. This fact is uncontested. As James Howe pointed out the ASA is "industry guidance for pressure piping facilities but is not a law or regulation, so it would be unfair to hold any company to that industry guidance in hindsight."[315] There is no evidence in the record to establish how widely the 1935 ASA or its successor versions was followed. One cannot conclude it was "imprudent" for PG&E to fail to implement a voluntary industry guideline without knowing if the guideline was generally accepted in the gas pipeline industry and relied upon as an industry practice.[316] Mere publication of a proposed guideline does not make the 1935 ASA or its successors an industry standard. In fact, the only evidence in the record is that PG&E started following the ASA guidance in 1955 when ASA B31.1.8 was adopted by the American Society of Mechanical Engineers ("ASME").[317]

Second, the 1935 ASA and its successor versions prior to 1955 <u>do not</u> require hydrostatic testing following installation of most transmission pipelines. It is correct that all of the versions of the ASA called for hydrotesting at the pipeline manufacturer site <u>prior</u> to installation but pre-

[314] D.87-06-021 (1987 Cal. PUC LEXIS 588, *28-29; 24 CPUC 2d 476); D.02-08-064 (2002 Cal. PUC LEXIS 534, *7-10); D.90-09-088 (1990 Cal PUC LEXIS 847, *23-25, 37 CPUC 2d 488, 499).

[315] Ex. 21, PG&E Rebuttal, p. 10-11, lines 3-5.

[316] Tr. (Pocta), p. 2284, lines 17-20.

[317] Ex 75, PG&E Response to DRA 045-07(a). PG&E's practice, starting in 1955, was to follow ASA B31.1.8, including pre-service hydrostatic testing.

installation requirements are not relevant in this proceeding.[318] However, there was no general requirement to hydrostatically test all gas transmission pipelines after installation until the 1955 version of the ASA code. And the pressure testing standards that did apply to some transmission pipe under those pre-1955 versions of the ASA do not come close to achieving modern standards. For example, in the ASA version issued just prior to 1955, the "air or gas" testing standard applicable to most gas transmission pipe is only 50 psi above working pressure.

From 1935 until the 1955 version, the ASA divided piping into two divisions—Division 1 addresses piping "within the boundaries of cities and villages" and Division 2 addresses piping in compressing stations, cross-country transmission systems and outside the boundaries of cities and villages. This is an important distinction because most gas transmission pipe would have been located in Division 2 at that time.[319] In the 1935 version of the ASA, hydrostatic testing after installation is recommended in Division 1 (cities and villages) "where practicable." The "where practicable" qualifier is indicative of the early stages of hydrotesting technology and indicates that at the time, hydrostatic testing could only be used in limited circumstances. The evidence in this case shows that the technology for post-installation hydrostatic testing did not become widely used until the 1950's;[320] therefore it is unclear if there are any circumstances where it was practicable in the industry to hydrotest gas pipelines within cities and villages (Division 1) until the 1950s.[321] Most importantly, for Division 2, which addresses gas piping in compressing stations, cross-country transmission systems and outside the boundaries of cities and villages, there was no requirement to conduct hydrostatic tests until the 1955 version of the

[318] Ex. 21, PG&E Rebuttal, p. 10-9, lines 16-29.

[319] Ex. 21, PG&E Rebuttal, p. 10-10, lines 1-20.

[320] Ex. 21, PG&E Rebuttal, p. 10-9, footnote 15, citing a 1998 report which states, "In the early 1950's testing equipment, procedures and technology were developed to test pipelines with water, and some operators began hydrostatic testing."

[321] The only evidence that DRA's witness relied upon to suggest PG&E should have hydrotested every pipeline after installation starting in 1935 was the 1935 ASA document itself. DRA's witness did not provide any other evidence to support a finding that hydrostatic testing after installation was "practicable" in 1935 or any other time prior to the 1950s. Tr. (Pocta), pp. 2278-79.

ASA.[322]

Here is a summary of the hydrostatic testing requirements and technical testing standards for each version of the ASA, from 1935 to 1963:

- 1935 ASA: For Division 2 (gas piping in compressing stations, cross-country transmission systems and outside the boundaries of cities and villages) there is no hydrostatic testing requirement after installation. For Division 1 (within the boundaries of cities and villages), hydrostatic testing is recommended after installation but only "to be applied where practicable."[323]
- 1942 ASA: For both Division 1 and Division 2, the ASA recommends a pressure test with "air or gas." There is no reference to a hydrostatic test after installation of the pipe. The technical standard calls for an air or gas test of Division 1 pipes to 150 percent of service pressure and for Division 2 pipes to "50 psi greater than the maximum service pressure."[324]
- 1944 and 1947 ASA: No modification of pressure testing recommendations for piping systems.
- 1951 ASA: The ASA states that after installation all pipes should be "capable of withstanding a test pressure" of 150 percent of maximum service pressure for Division 1 and 50 psi greater than the maximum service pressure for Division 2. This version does not specify if pressure tests should be by "air or gas" or other method but does state that "where internal fluid pressure test is made after installation" it shall not exceed 150 percent of maximum service pressure for Division 1 and 50 psi greater or 120 percent of maximum service pressure for

[322] Ex. 21, PG&E Rebuttal, p. 10-10, lines 1-20. As discussed below, in some versions of the ASA, there were recommendations to conduct "air or gas" pressure tests to a standard of 50 psi above service pressure for Division 2 piping.

[323] Ex. 143, DRA Direct (Pocta), Appendix A, pp. 2-4; Ex. 21, PG&E Rebuttal, p. 10-9, line 9—p. 10-10, line 20.

[324] Ex. 143, DRA Direct (Pocta), Appendix A, pp. 4-5.

Division 2.[325]

- 1952 ASA: Same pressure test standards as 1951.
- 1955, 1958, 1963 ASA: No longer divides piping into Division 1 and 2. Adopts Class locations based on population and development density near piping. Requires a post installation gas or hydrostatic test. Class 1 – 1.1 times maximum operating pressure. Class 2 -- 1.25 times maximum operating pressure. Class 3 and 4 – 1.4 times maximum operating pressure. Record keeping standards are adopted for the first time, including documentation of test pressure and medium.

Third, as DRA acknowledges, there are no requirements to keep hydrostatic pressure test records in the 1935 ASA and such a requirement did not appear in the ASA until 1955.[326] Even if hydrostatic pressure tests were conducted during this era, PG&E cannot be found to have been imprudent for failing to follow the pre-1955 ASA standard if the records of such tests are no longer available. DRA argues that the CPUC's General Order 28 created a general obligation to retain records, but there are two flaws in this argument. First, GO 28 is a document preservation requirement. It assumes that the utility has created a record and, once created, comes within GO 28's preservation rules. Nothing contained in the ASA prior to 1955 required the operator to create (much less maintain) a record of a pressure test. Second, GO 28 addresses recordkeeping necessary for documenting the entries in the utility's financial books and accounts and has nothing to do with pipeline safety. The purpose of GO 28 is to preserve records "supporting each and every entry in the following general books" including the accounts payable ledger, accounts receivable ledger, general and auxiliary ledgers, journals and cash books, annual reports and records pertaining to the "original cost," and "depreciation and replacement" of property, equipment and plant.[327] GO 28 does not establish an independent requirement to maintain gas

[325] Hydrostatic testing is specifically required at the mill, prior to installation. Ex. 143, DRA Direct (Pocta), Appendix A, pp. 6-7.

[326] Tr. (Pocta), p. 2280, line 26—p. 2281, line 15; Ex. 143, DRA Direct (Pocta), Appendix A, p. 12, lines 11-15.

[327] General Order No. 28, p. 1; Tr. (Howe), p. 1202, line 21—p. 1205, line 17; Ex. 21, PG&E Rebuttal, p. 10-10, lines 24-32.

pipeline pressure tests.

In summary, DRA has proposed that every hydrostatic test under the PSEP should be ineligible for cost recovery if the pipe was placed in service in 1935 or later based on the argument that PG&E was imprudent if it failed to hydrostatically test all of these pipes under the 1935 ASA and its successor versions. It is not imprudent for a utility to decline to follow voluntary industry guidance when there is no requirement to do so, particularly in its earliest stages of development and evolution. Even if one were to accept DRA's premise for the sake of argument that it was imprudent for a utility not to follow the ASA starting in 1935, the argument fails because there was not a general requirement in the ASA prior to 1955 that a gas operator hydrostatically test all of its gas transmission pipelines. While it is arguable that some Division 1 pipe should have been hydrostatically tested "where practicable" under the 1935 ASA, one would have to evaluate which PG&E gas transmission pipelines fall within the Division 1 "boundaries of cities and villages" as those boundaries existed from 1935 to 1955 and then evaluate if it was "practicable" to conduct hydrostatic testing at that site. There is no evidence in the record to support a finding that any hydrotesting proposed in the PSEP meets this test; in fact, the only evidence supports the proposition that the equipment necessary to conduct post-installation hydrostatic testing was not generally available until the mid-1950s. In the latter years, the pre-1955 ASA iterations began to recommend post-installation "air or gas" testing—not hydrostatic testing—in Division 2 pipes but there is no criteria for this testing other than to specify that the tests should be 50 psi above operating maximums. Even if PG&E had followed these guidelines for Division 2 pipes, it would not have conducted hydrostatic tests and the gas or air tests would not have been in accordance with technical standards that come remotely close to modern (or even 1955) standards. When adding on the absence of any guidance or direction to create or maintain a record of such air or gas pressure tests, it becomes clear that DRA's proposal to disallow recovery for all PSEP hydrotests on pipes installed in 1935 or later on the grounds of imprudence is overreaching, unsupported and unreasonable.

3. PG&E's Decision Not To Emphasize Hydrotesting As Part Of TIMP Complied With The TIMP Regulations And Was Clearly Vetted With And Approved By The CPUC In The GT&S Rate Case

DRA argues that hydrostatic testing costs under the PSEP should be disallowed on the grounds that the work is "deferred maintenance" that should have been completed under its Transmission Integrity Management Program.[328] DRA states that "[i]n many instances, hydrostatic testing could and/or should have been performed as part of the integrity program." However, the only instance DRA cites in support of this factual assertion is the CPSD investigation report in the San Bruno OII pertaining to Line 132 which alleges (in part based on findings in the NTSB report) that PG&E did not have accurate information to assess threats on several Line 132 segments and, if it had accurate data, it would have used a different method to assess manufacturing threats.[329]

This single allegation does not justify wholesale disallowances of PSEP hydrostatic testing costs, particularly on gas transmission lines other than Line 132. First, this allegation has been raised in the San Bruno OII, but PG&E has not yet submitted its response to the CPSD report and the resolution of contested issues is far from final. If the allegation is substantiated and the Commission determines that some penalty, disallowance or other relief is warranted, that will be decided in the San Bruno OII and the specific allegation should not be litigated a second time in this proceeding.

Second, there is no evidence to support DRA's broad allegation that "hydrostatic testing could and/or should have been performed as part of the integrity program." The regulatory requirements for TIMP are set forth in 49 CFR, Part 192 Subpart O. Four methods of integrity assessment are authorized for assessing time dependent threats: smart pigging, pressure testing, direct assessment and other technology.[330] When PG&E presented its plan for implementing TIMP as part of its 2005 GT&S Rate Case, PG&E clearly stated that "[d]irect assessment and the

[328] Ex. 143, DRA Direct (Pocta), p. 25, lines 3-22.

[329] Ex. 143, DRA Direct (Pocta), p. 25, line 13—p. 26, line 6.

[330] Ex. 2, PG&E Direct, p. 2-16, line 6—p. 2-17, line 10.

associated physical excavations to inspect the pipeline are the primary Pipeline Integrity Program expenditures" and that "pressure testing will be used on a limited basis since it requires the pipeline to be temporarily taken out of service to perform the test."[331] No costs for hydrotesting were included in PG&E's O&M forecast in the 2005 GT&S rate case. PG&E also presented in the 2005 GT&S rate case a strategy for completing the ten year baseline assessment of the HCA gas transmission segments in its system covered by TIMP. The accompanying table listing the assessment strategy and associated mileage shows that PG&E intended to rely exclusively on ILI, direct assessment and pipeline replacement. The strategy did not include hydrostatic testing because that method requires the transmission line to be taken out of service.[332] Through 2010, of the 834 miles of HCA gas transmission pipeline assessed under TIMP, approximately 171 miles have been assessed through ILI, 649 miles have been assessed through direct assessment, and 14 miles have been assessed through pressure testing.[333] PG&E's 2011 GT&S Rate Case includes a 2011 to 2014 TIMP assessment plan which relies on ILI and direct assessment and indicates that "no segments are currently planned for assessment by pressure testing."[334]

The evidence demonstrates that 1) in its TIMP strategies and implementation, PG&E relied on direct assessment and ILI as its primary assessment methods rather than pressure testing; 2) both of these assessment methods are legally authorized assessment methods that are fully compliant with Part 192 Subpart O; 3) PG&E clearly notified the Commission and parties through the GT&S rate case proceedings of its TIMP implementation strategies; 4) PG&E did not ask for or receive funding for hydrostatic pressure testing work in prior or current GT&S rate cases; and 5) the Commission approved PG&E's TIMP implementation strategies and funding requests in the decisions approving the GT&S rate cases. One cannot infer from these facts that the PSEP includes "deferred" hydrostatic testing that was planned or funded in prior GT&S rate

[331] Ex. 72, PG&E 2005 GT&S Rate Case Testimony, p. 3-8, lines 16-28.

[332] Ex. 72, PG&E 2005 GT&S Rate Case Testimony, pp. 4-11—4-14.

[333] Ex. 2, PG&E Direct, p. 2-17, Table 2-5.

[334] Ex. 2, PG&E Direct, p. 2-18, Table 2-6.

cases. Nor can one conclude from the evidence that PG&E should have conducted hydrostatic testing in the past rather than pursuing the other legally authorized methods of integrity assessment. The evidence does support a finding that PG&E was very clear about its TIMP implementation strategy, that the Commission approved and funded the strategy, and that PG&E reasonably implemented its strategy following Commission approval.

F. The Recommendations Of Parties To Reduce PG&E's ROE Are Unreasonable And Will Harm Customers By Increasing The Cost Of Debt And Capital That Must Be Raised To Finance PSEP Safety Improvements

Several parties propose to reduce the return PG&E is allowed to recover for capital expenditures made under its PSEP. These proposals include: setting the allowed cost of capital equal to PG&E's cost of debt;[335] reducing the allowed return on equity ("ROE") by 500 basis points;[336] reducing allowed ROE by 200 basis points;[337] and reducing allowed ROE to the bottom of the "reasonable ROE range" previously identified by the Commission (or "from 11.35 percent to 10.2 percent"—which "would reduce PG&E's after-tax return by about 99 basis points" below PG&E's approved ROE).[338] These proposals fail to distinguish between investments needed to meet new safety-related standards introduced by the Commission, and other ratemaking decisions relating to any Commission findings of errors or omissions by PG&E in the past. The intervenors' ROE-adjustment proposals for PSEP-related investments in this proceeding would effectively double count for past conduct, with penalties in this proceeding as well as in investigatory proceedings (currently underway.)

Ms. Tierney analyzed these proposals under her five ratemaking principles and concluded that the proposed ROE adjustments would undermine the Commission's goal of improving the safety of the state's natural gas transmission pipeline system. Such adjustments would adversely affect the utility's incentives to undertake PSEP investment—just the opposite of what is needed

[335] Ex. 98, TURN Direct (Long), pp. 16-17.

[336] Ex. 123, NCIP Direct (Beach) , p. 25

[337] Ex. 143, DRA Direct (Pocta), p. 28

[338] Ex. 98, TURN Direct (Marcus), p. 9

to support raising the priority of safety. Such adjustments would result in customers not bearing the true cost of improvements in pipeline infrastructure and diminish the utility's ability to attract capital in support of investments needed to maintain and improve the company's service quality, including those under the PSEP.[339] In effect, these adjustments make an end run around the ongoing cost-of-capital proceeding in which the Commission will determine PG&E's appropriate cost of capital going forward.

While one-time disallowances, as PG&E has proposed, can materially affect the utility's earnings and its financial position more generally, they do not affect any of the utility's decisions about its operations or investments, except to the extent that they cause the utility to invest in compliance to avoid incurring these penalties in the future.

As Ms. Tierney points out:

> This would place PG&E in a no-win situation: if the company undertook the needed investment, its rates would be insufficient to fully compensate investors. This would create challenges and higher costs for PG&E to attract the capital needed to undertake investments in the first place. This would harm ratepayers by raising the cost of capital built into rates. Consequently, positive investor perceptions about the long-run ability to receive a full return on investment, supported by an allowed ROE that reflects market realities, are necessary to making PG&E competitive in capital markets and allowing it to attract the capital needed to make needed investments. Absent such positive perceptions, a "vicious cycle" can emerge, which becomes further fueled by market participant perceptions regarding regulatory risk from state regulators.[340]

Intervenor proposals to reduce PG&E's allowed ROE also fail to appreciate the importance of providing an appropriate rate of return so that PG&E can raise the financing (debt and equity) necessary to implement the aggressive schedule and extensive scope of the PSEP at reasonable cost.[341] These proposals would result in PG&E's cost of capital being set at an

[339] Ex. 21, PG&E Rebuttal, p. 2-13, line 22—p. 2-14, line 1.

[340] Ex. 21, PG&E Rebuttal, p. 2-14, line 14—p. 2-15, line 4.

[341] Ex. 21, PG&E Rebuttal, p. 2-15, lines 5-8.

artificially low rate that does not reflect the returns on investments in other businesses with corresponding risks, which is in conflict with the Hope and Bluefield standards.[342]

One argument made by TURN is that PG&E should not be allowed to "profit" from investments made under the PSEP.[343] This type of argument is flawed. First, by suggesting that "profit" is somehow different from a return on investment, it fails to recognize the fundamental reality that investors need compensation for the use of their money, and the fundamental pillar of cost-of-service regulation that rates must include an allowed return on investment (including not only debt but equity).[344] Their connotation is that PG&E would be unjustly "profiteering" by making investments to meet new safety-related requirements; but this ignores the realities of capital markets in which investors place their capital in investments that offer them the opportunity to make market returns. If the returns PG&E can offer are diminished, this will hamper its ability to attract financing at reasonable cost in competitive capital markets.[345]

Mr. Bottorff raises three concerns with the proposals to reduce PG&E's rate of return on PSEP-related investments on a prospective basis: 1) the issue of "punishments" or disallowances for past conduct should be addressed in the OIIs and not litigated another time in this proceeding; 2) discouraging investment in safety improvements (by reducing the return only on those investments) results in a misalignment of safety and ratemaking policies; and 3) a reduction in ROE would adversely affect PG&E's ability to attract capital. Financing the billions of dollars of investment in PSEP Phase 1 and 2 will require PG&E to finance large sums through the equity and debt markets. PG&E can only raise funds if investors think they can earn a competitive rate of return on capital and lenders/creditors have high assurance the company will be strong enough to repay in full what it has borrowed. "If the Commission adopts a punitive, noncompensatory ratemaking structure in the PSEP, this will undermine PG&E's ability to attract capital and play

[342] Ex. 21, PG&E Rebuttal, p. 2-15, lines 14-20.

[343] Ex. 121, TURN Direct (Long), p. 6.

[344] Ex. 21, PG&E Rebuttal, p. 2-16, line 8-14.

[345] Ex. 21, PG&E Rebuttal, p. 2-16, lines 15-20.

this critically important role in enhancing the safety of the state's infrastructure."[346]

Finally, Mr. Bottorff was asked by ALJ Bushey about the relative difference to customers and the company of a penalty, a cost disallowance and a rate of return reduction.[347] Mr. Bottorff explained that a penalty is paid to the state General Fund and is not tax deductible; thus every dollar of fine effectively costs the company $1.60. In addition, customers get no benefit (since it would not offset rates).[348] A disallowance of $1.00 in revenue requirement results in one dollar being credited to customers to offset rates and costs the company $1.00 in lost revenue.[349] An ROE reduction that results in a revenue requirement reduction of $1.00 also results in customers paying $1.00 less in revenue requirement and the company losing $1.00 of revenue but it also has a negative impact on the costs of doing business. "If it's more difficult to attract investors because now you've got a lower return, then it's not just a dollar any more . . . there's a larger consequence to both customers and our company going forward if that's the path the Commission takes."[350]

G. Contrary To TURN's Argument, There Is No Legal Obligation To Conduct A Duplicative Reasonableness Review Of Past Actions In The PSEP Proceeding

An issue raised by TURN is whether the Commission has a legal obligation to review past conduct as part of its ratemaking determination in the PSEP proceeding. TURN cites Public Utilities Code Sections 451and 463 and argues these statutes compel the Commission to conduct a historic reasonableness review of gas operations and disallow costs of capital projects resulting from unreasonable errors and omissions.[351] Clearly, the Commission is required to evaluate if the proposed PSEP rates are just and reasonable under Public Utilities Code section 451. But this

346 Ex. 21, PG&E Rebuttal, p. 1-15, line 21—p. 1-16, line 6.

347 Tr. (Bottorff), p. 954, line 11— p. 957, line 23.

348 Tr. (Bottorff), p.957, lines 6-11.

349 Tr. (Bottorff), p. 957, lines 22-23.

350 Tr. (Bottorff), p. 956, lines 1-5; p. 957, lines 13-23.

351 Ex. 121, TURN Direct (Long), p. 3

does not require a review of historic gas operations from the 1920s to the present day. In this case, Section 451 requires the Commission to evaluate whether PG&E's cost estimate for the PSEP work scope and the associated ratemaking proposal are just and reasonable. PG&E in the PSEP filing has provided hundreds of pages of testimony and workpapers describing the technical basis of proposed work scope, how it was developed, and why it complies with D.11-06-017. PG&E has provided a detailed cost forecast, described its cost forecasting methodology, and presented detailed workpapers for every project that is proposed. PG&E has provided a rate and cost allocation proposal, specified a revenue requirement and proposed procedures for tracking costs and reporting. The Commission will fully discharge its legal obligations under Sections 451 and 463 by reviewing the reasonableness of PG&E's testimony, workpapers and ratemaking proposals and determining if this would result in a just and reasonable rate.

The applicable requirements under Public Utilities Code Section 463 are misconstrued by TURN. This statute requires that for large capital projects totaling $50 million or more the CPUC shall disallow any costs resulting from "unreasonable error or omission related to the planning, construction or operation" of the plant.[352] Thus, the review that is required by Section 463 is of the planning, construction and operation of the specific capital asset over $50 million. Importantly, Section 463.5(a) clarifies that Section 463 "does not require the commission to undertake a reasonableness review of recorded costs to determine the reasonableness" of plant that may exceed $50 million if the CPUC has adopted "an estimate of the reasonable costs in any proceeding." In the PSEP filing, PG&E has followed typical Commission practice and asked the CPUC to review and adopt PG&E's forecast of PSEP costs as a reasonable estimate. This approach is in full compliance with Section 463 and 463.5(a). Section 463 does not contemplate a historic reasonableness review of every act or omission that may have led the utility to propose the capital project.

TURN also argues that the OIIs can only address "violations" of law, regulations or

[352] The statute says this is a "clarification of the existing authority of the commission" and doesn't "limit or restrict any power or authority of the commission conferred by any other provision of law." Pub. Util. Code Sec. 463(a).

Commission orders and that issues of "past prudence," as opposed to "past violations," cannot be reviewed in the OIIs. TURN has not cited any support for its position that the Commission cannot as a matter of law review past "errors and omissions" in the OIIs. In fact, in the Order instituting I.12-01-007, the Commission states "[t]his investigation will focus on PG&E's past actions and omissions and determine whether PG&E has violated laws requiring safe utility gas practice. The Commission has the broad authority to impose fines or other remedies if such violations are proven."[353] CPSD has taken the position in the San Bruno OII that imprudent past utility conduct can result in a "violation" of Public Utilities Code Section 451. CPSD has proposed disallowances of over $575 million based on allegations in the Overland Report that pertain to the past management of the gas transmission budget and revenues, even though PG&E's conduct is not alleged to have violated any law or CPUC order. [354]

TURN is also incorrect in its assertion that the CPUC can only impose fines or penalties in the OIIs. I.12-01-007, as quoted above, specifically finds the Commission has broad legal authority to impose "other remedies" besides fines. Public Utilities Code Section 2104 states that if a penalty for a violation of law or Commission order is adopted by the Commission, the penalty shall be paid to the general fund; however, the statute does not state that this is the only remedy available to the Commission. In fact, the CPUC has required remedial actions and has the authority to require the crediting of future customer rates to address its findings. In an investigation concerning PG&E's billing practices, the Commission ordered PG&E to pay

[353] I.12-01-007, p. 10; see also Tr. (Bottorff), p. 810.

[354] Tr. (Tierney), p. 1087, line 1—p. 1088, line 15. In the San Bruno OII, CPSD asserts that PG&E violated section 451 by "management failing to foster a culture that valued safety over profits at PG&E." The Overland Report did not focus on whether anything PG&E did was a violation of any law or CPUC order. In terms of actual spending compared to the adopted amounts, the Overland Report never says that PG&E violated any law or rule by not spending the full adopted amount (per their analysis). As to the "excess" GT&S revenues, the Overland Report acknowledges that PG&E was allowed to spend that money on general corporate purposes ("PG&E could have used the surplus revenues, at least in part, to improve gas safety. Instead, PG&E chose to use the surplus revenues for general corporate purposes."). As to the funding for GT&S operations, they found that "the priority that PG&E gave to safety and reliability requirements in the 2008 through 2010 budget processes was well outside of standard industry practice," but they did not find that there was any violation of law. I.12-01-007, Consumer Protection and Safety Division's Incident Investigation Report – September 9, 2010 PG&E Pipeline Rupture in San Bruno, California, filed 1/12/12, CPSD's recommendations 31-33.

refunds to customers for amounts charged under its backbilling and estimated billing procedures, rather than requiring PG&E to pay a fine to the general fund. The Commission ruled "[c]onsistent with its authority under Public Utilities Code section 701, the Commission may do all things necessary to further its regulation of PG&E's practices and service, including making appropriate remedial orders to address violations of law and tariff that have harmed customers; in this instance refunds to customers who were harmed during the 2000-2005 investigation period, in the approximate amount of $35 million, are appropriate."[355]

TURN's argument for a prudence review of past gas operations violates the rule against retroactive ratemaking. As discussed above, Public Utilities Code Sections 451 and 463 pertain to the establishment by the Commission of just and reasonable rates. TURN is seeking a mega-prudence review of the rates established for gas operations reaching back to the 1920s or potentially even earlier and asking the Commission, in effect, to make a finding the rates set for gas operations decades ago were unreasonable. The rule against retroactive ratemaking was established by the Supreme Court in <u>Pacific Telephone and Telegraph Co. v. PUC</u>.[356] It provides that "the commission may prescribe rates only prospectively" and cannot "reopen" rates developed in a "general rate proceeding, which is now final and no longer subject to review."[357] PG&E's past rates for gas transmission were adopted and approved by the Commission through a long series of decisions that are now final and no longer susceptible to review. Conducting a

[355] In D.07-09-041 the Commission ordered PG&E to refund approximately $35 million to customers in an investigation regarding PG&E's "backbilling" and "estimated billing" practices. D.07-09-041, Conclusion of Law 9, p. 60. The Commission further found that "[n]o penalty is warranted for PG&E's violation of Rule 17.1." Id., Conclusion of Law 24, p. 61; Bottorff, Tr. 951, l. 19 to 952, l. 10. See D.08-09-038 (in resolution of an investigation alleging fraudulent reporting of SCE's PBR results, the CPUC ordered refunds to customers of $28 million for customer satisfaction awards, $20 million in health and safety awards, and approximately $32 million in revenue requirement related to the administrative costs of the program. The CPUC also fined SCE $30 million for violations of the Public Utilities Code.)

[356] In that decision the Supreme Court held that the Commission lacks "the power to roll back general rates already approved by it under an order which has become final, or to order refunds of amounts collected by a public utility pursuant to such approved rates and prior to the effective date of a commission decision ordering a general rate reduction." 62 Cal 2d 634,650 (1965). The Court explained that this rule flows directly from Section 728 of the Public Utilities Code, which expressly limits the Commission's power to establish rates "to be thereafter observed." *Ibid.*

[357] *City and County of San Francisco v. PUC*, 39 Cal 3d 523, 534-35 (1985).

prudence review of historic PG&E rate requests and historic operational performance underlying the rate requests would reopen the rates set in these proceedings and violate the rule against retroactive ratemaking.

Another problem with TURN's position is that it opens the door to PG&E being penalized multiple times for the same conduct. The intervenors focus on PG&E's recordkeeping and its historic spending on gas operations, as discussed in the Overland Report and Recordkeeping OII. It is clear that CPSD has recommended penalties or disallowances related to PG&E's historic spending on gas operations in those proceedings. Disallowing PSEP costs for alleged past imprudent behavior in the PSEP proceeding would punish PG&E for the same conduct being reviewed in the OIIs.

IX. THE COMMISSION SHOULD APPROVE PG&E'S RATEMAKING PROPOSAL

This section describes PG&E's ratemaking proposal for capital and expense costs required to implement Phase 1 of the PSEP for 2011 through 2014. This ratemaking proposal is not a "business as usual" approach. PG&E proposes to modify several aspects of normal cost of service ratemaking to ensure a proper safety focus. Under typical cost of service ratemaking, a utility submits a forecast of costs for anticipated work for the Commission's review and approval. The utility then has the discretion to manage its authorized revenues to meet its utility obligations and if it can complete the work at a lower cost, the cost savings can be reallocated to other utility uses or flowed to the bottom line.[358] The Commission in this proceeding challenged utilities to evaluate whether traditional ratemaking results in an adequate safety focus and to consider different measures to align ratemaking and safety. PG&E's proposed changes to traditional ratemaking can be summarized as follows: 1) PG&E has proposed a fixed four year

[358] "We know in prospective test year ratemaking that out adopted estimates of revenues and expenses may be at variance with actual hindsight experience. But we do not view this as a problem, because we are extending to utility management an opportunity and incentive to find ways to conduct operations for less than projected. When it can do this it flows the benefit to the utility's bottom line, which means profits. In the short term, between general rate proceedings, the shareholders benefit when the company's management can 'do it for less,' and correspondingly, ratepayers ultimately benefit because the productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement." D.85-12-071, 19 CPUC 2d 246, 254.

budget for PSEP work. PG&E must complete the work scope within that budget or, if unexpected circumstances arise, seek Commission approval for a change in the budget or, alternatively, a change in the work schedule; 2) Funds authorized by the Commission must be used for PSEP work; there can be no reallocation to other utility functions; 3) PG&E will recover in rates its actual costs (not to exceed the CPUC-authorized budget), thus eliminating any potential for upside if actual costs are lower than forecasted; 4) at the Commission's direction, PG&E has proposed a shareholder/customer sharing approach which will result in shareholders absorbing a significant share of costs that would typically be recoverable in rates; and 5) PG&E will provide extensive reporting of its on-going PSEP work. These reports will identify the progress on scheduled projects, the costs expended, and any changes in project scope, priority, or schedule. The reporting process will provide an unprecedented level of transparency over how PSEP Phase 1 is progressing and it will identify any challenges that PG&E is confronting so that the Commission can monitor and intervene on a real-time basis (as opposed to waiting for an after the fact review years later). Taken together, the elements of PG&E's ratemaking proposal will ensure that there is a proper focus on and accountability for critical PSEP safety work

PG&E requests that the Commission approve the following elements of PG&E's cost recovery proposal:

1. <u>Cost Estimate</u>: Approve PG&E's forecast capital expenditures and expenses for PSEP Phase 1, authorize the recovery of the associated revenue requirements within the limits of the approved capital and expense forecasts, and find that these costs are recoverable in rates without the need for after the fact reasonableness review. Phase 2 PSEP costs and the associated revenue treatment will be addressed in a subsequent proceeding.
2. <u>Sharing Approach</u>: Approve PG&E's shareholder/customer cost allocation proposal, as described above.
3. <u>Balancing Accounts For True-Up To Actual Costs</u>: Authorize PG&E to establish a new Gas Pipeline Expense Balancing Account ("GPEBA") to track the

difference between the Phase 1 forecast expenses and actual Phase 1 recorded expenses.[359] If PG&E spends less than the amount authorized by the Commission, PG&E will refund the balance to customers at the end of Phase 1. If PG&E spends more than the authorized amount, PG&E must seek Commission authorization to recover the difference in rates through an advice letter filing, as described below. PG&E will also establish two new Gas Pipeline Safety Balancing Accounts ("GPSBA"); one for core gas customers and another for noncore gas customers, with separate subaccounts to track the adopted forecast expenses, actual capital-related revenue requirements, and actual revenue collected.[360] Together the GPEBA and GPSBAs will provide a "true up" to ensure that PG&E will only recover in rates costs that are actually expended on the PSEP.

4. Memorandum Account: Approve, with modifications, PG&E's May 5, 2011 request to establish the Natural Gas Transmission Pipeline Safety and Reliability Memorandum Account ("NGTPSRMA") and authorize PG&E to track and record its actual revenue requirements for its 2011 and subsequent Implementation Plan costs to the NGTPSRMA. The memorandum account would be modified to reflect PG&E's shareholder allocation proposal that 2011 Implementation Plan costs would be borne by shareholders.

5. Process For Review Of Adjustments To Forecasts: Authorize PG&E to submit a

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[359] Ex. 2, PG&E Direct, Attachment 8A is PG&E's pro forma tariff for the GPEBA.

[360] Each GPSBA will record, on a monthly basis, the customer funded revenue requirements associated with the forecast Implementation Plan expenses, actual capital expenditures for in service capital projects and actual revenue collected through Core and Noncore GPS rates. Any resulting over collection or under collection will be trued up annually via PG&E's AGT advice letter. PG&E proposes to establish three subaccounts in both GPS balancing accounts, each related to the Backbone, Local Transmission, and Storage revenue requirements established in this proceeding. Into each of these subaccounts, PG&E will record the revenue requirements associated with the forecast Implementation Plan expenses, actual capital expenditures for in service capital projects, and the actual revenue collected through the subcomponents of the Core and Noncore GPS rates. Ex. 2, PG&E Direct, p. 8-11, line 13—p. 8-12, line 32. Ex. 2, PG&E Direct, Attachments 8B and 8C are PG&E's pro forma tariffs for the Core GPSBA and Noncore GPSBA, respectively.

Tier 3 advice letter to adjust the project capital and expense forecasts should Phase 1 costs exceed the forecast.

6. Reporting Requirements: Approve PG&E's proposal for semi-annual reporting on the PSEP, similar to that approved in PG&E's 2011 GT&S Rate Case, Decision 11-04-031. The reporting requirements will make progress on the PSEP transparent to the public and the Commission. The key attributes are: (1) semi-annual reporting to the Commission staff on March 1 and September 1 of each year; (2) amount of funds budgeted and spent on PSEP work for the current reporting period, calendar year and Phase 1 period; (3) a construction status of projects undertaken; (4) a quantitative measurement of the progress on the miles of pipe tested, pigged, and replaced; and (5) an explanation for new projects being constructed that were not initially forecast.

A. Cost Forecast and Revenue Requirement

PG&E has proposed a forecast for capital and expense for Phase 1. PG&E's cost estimates, while detailed in nature, are forecasts based on general assumptions of unit costs, tailored to reflect project specific features and engineering judgment and experience. The actual costs of this program will vary based upon job specific circumstances, schedule changes, permitting requirements, market conditions for materials, equipment and labor and a number of other factors. PG&E's cost recovery proposal accounts for this uncertainty by including a true-up of rates to reflect the actual costs of the projects.

Under PG&E's ratemaking proposal, these proposed forecasts for expense and capital are binding on PG&E for the four year period, unless the Commission authorizes a modification to the budget. PG&E requests that the Commission approve the forecasts as reasonable and find that no after the fact reasonableness review need be conducted if actual costs are at or below the adopted forecasts for Phase 1.

The following tables show PG&E's forecast for expense and capital for Phase 1 of the

PSEP:

TABLE 1[361]
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF IMPLEMENTATION PLAN PHASE 1 EXPENSES
($ IN MILLIONS)

Line No.	Description	2011(a)	2012	2013	2014	Total
1	Pipeline Modernization Program	$122.7	$94.9	$87.3	$102.8	$407.7
2	Valve Automation Program	1.6	2.6	3.1	3.8	11.1
3	Pipeline Records Integration Program	55.7	88.1	32.4	7.2	183.4
4	Interim Safety Enhancement Measures	–	1.0	1.1	1.1	3.2
5	Program Management Office	1.6	3.5	3.4	3.4	11.9
6	Contingency	39.1	41.0	27.5	25.6	133.2
7	Total Expenses	$220.7	$231.1	$154.8	$143.9	$750.5

(a) The 2011 expenses will be funded by shareholders, as described in Chapter 8 of Exhibit 2.

The Implementation Plan Phase 1 forecast of expenses for the four year implementation period from 2011 to 2014 is $750.5 million. PG&E proposes that shareholders will fund the actual 2011 expenses and post-2011 expenses will be collected in rates from customers. For purposes of setting authorized 2012 revenues, PG&E proposes to update its 2011 forecast PSEP expense to actual expense once year-end data are available. PG&E would determine its authorized 2012 expenses by summing the authorized forecasts for 2011 and 2012 PSEP expenses and subtracting its actual 2011 PSEP expenses.

PG&E's capital expenditures forecast is as follows:

[361] Ex. 21, PG&E Direct, p. 1-16, Table 1-2.

TABLE 2[362]
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF IMPLEMENTATION PLAN PHASE 1 CAPITAL EXPENDITURES
($ IN MILLIONS)

Line No.	Description	2011(a)	2012	2013	2014	Total
1	Pipeline Modernization Program	$32.8	$228.9	$310.5	$355.9	$928.1
2	Valve Automation Program	13.7	39.5	53.3	26.0	132.5
3	Pipeline Records Integration Program	7.4	42.3	27.2	25.7	102.6
4	Interim Safety Enhancement Measures	–	–	–	–	–
5	Program Management Office	3.0	6.6	6.7	6.6	22.9
6	Contingency	12.0	67.0	82.6	85.7	247.3
7	Total Capital Expenditures	$68.9	$384.3	$480.3	$499.9	$1,433.4

(a) The 2011 capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011, forecast at $1.4 million, will be funded by shareholders, as described in Chapter 8 of Exhibit 2.

The total PSEP Phase 1 capital expenditures for the four year implementation period from 2011 to 2014 is forecast to be $1.4 billion. Rather than following the typical approach of recovery based on a forecast of capital expenditures in rates, PG&E proposes that the capital expenditures would be recovered from customers based upon the actual cost of the project (as opposed to a forecast) and after the in service date (*i.e.*, operative date) of the project. In this way, customers only pay in rates for those capital projects that PG&E puts in service. Revenue requirements associated with Implementation Plan capital additions recorded by November 30 of each year will be incorporated into PG&E's supplemental AGT advice letter filings effective January 1 of the following year.[363] The costs recorded to the balancing account for Phase 1 would be limited to the Commission adopted forecast for capital expenditures.

The revenue requirement to be recovered from customers is shown in the following table:

[362] Ex. 21, PG&E Direct, p. 1-6, Table 1-3.

[363] For example, if a capital project goes in service in October 2012, PG&E will record in the GPSBAs the revenue requirement for the last three months of 2012, to be included in the GPS rate component beginning January 1, 2013, along with the 2013 revenue requirement for the same project.

TABLE 3[364]
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 REVENUE REQUIREMENT REQUEST
($ IN THOUSANDS)

Line No.	Revenue Requirement	2011	2012	2013	2014	Total
1	Capital-Only Revenue Requirement	–	$13,205	$63,981	$154,816	$232,002
2	Expense-Only Revenue Requirement	–	234,074	156,852	145,825	536,751
3	Total	–	$247,279	$220,833	$300,641	$768,753

Implementing this revenue requirement will require a large percentage increase in gas transmission service rate levels. However, it is important to put this increase in perspective. Gas transmission rates are a relatively small portion of an average customer's bill for gas service. It is the cost of the commodity itself—natural gas—that is the primary driver of a customer's monthly bill for natural gas service. The cost of the pipeline system needed to transport and deliver the gas to customers is a small part of their gas bill.

B. Memorandum Account

On May 5, 2011, PG&E filed a Motion to establish the NGTPSRMA to record PSEP costs.[365] The Commission will address cost recovery for PSEP activities in its decision on the filing. PG&E still requests that the Commission approve the NGTPSRMA so that PG&E may track and record its PSEP expenditures for 2011 and 2012, as tracking of these costs is necessary 1) to establish the rates for 2012 under the PSEP and 2) to track the total program costs for Phase 1, which under PG&E's cost recovery proposal would be subject to a binding budget for the four year period 2011-2014. PG&E's pro forma tariff for the modified NGTPSRMA is included as Attachment 8D to PG&E's direct testimony (Exhibit 2).

[364] Ex 2, PG&E Direct, p. 1-17, Table 1-5.

[365] PG&E made a similar request for NGTPSRMA in Advice Letter 3171-G on December 1, 2010. In Resolution G-3453, the Commission denied, without prejudice, PG&E's request, and concluded the appropriate proceeding in which to request the NGTPSRMA is this proceeding (R.11-02-019).

Under PG&E's cost recovery proposal, PG&E would be authorized to recover PSEP 2012 costs. PG&E's request for a memorandum account to track costs of implementing its gas safety program was timely filed in December 2010 and May 2011, well in advance of the January 1, 2012 cost recovery start date. Adopting the memorandum account with an effective date of January 1, 2012 would provide a means of implementing this proposal.

The Commission has legal authority to establish a retroactive effective date for memorandum accounts.[366] In D.12-04-021, the Commission authorized San Diego Gas and Electric Company and Southern California Gas Company to establish a "pipeline safety memorandum account" to track the costs of implementing their PSEP and document review costs.[367] The Commission authorized these utilities to retroactively record in the pipeline safety memorandum account the estimate of the implementation costs that would be incurred in the first year of PSEP implementation. This includes costs incurred in 2011 and 2012, prior to the April 20, 2012 Decision authorizing the establishment of the pipeline safety memorandum account. The Commission has thus established a memorandum account for Southern California Gas Company and San Diego Gas and Electric Company that includes the exact same scope and serves the exact same purpose as PG&E has proposed. It would be unreasonable, arbitrary and capricious, and unduly discriminatory for the Commission to deny PG&E the same relief. As Mr. Bottorff testified:

> PG&E has spent close to $300 million on PSEP activities in 2011. We will spend over $600 million in 2012. PG&E's proactive and supportive response to the CPUC's June 2011 decision to eliminate grandfathering of pre-1970 transmission pipeline is in contrast to the other gas utilities in the state that haven't begun work in earnest and will be permitted to wait until the Commission rules on their ratemaking applications. It's time for the CPUC and parties in this proceeding to work with us on a ratemaking framework that

[366] *S. Cal. Edison Co. v. Pub. Util. Comm'n*, 85 Cal.App.4th 1086, 1100 (2000).

[367] The Commission did not decide such costs are eligible for cost recovery; the purpose of the memorandum account is to "preserve the opportunity for the utilities to recover these costs in rates." D.12-04-021, p. 7.

> aligns safety and ratemaking and gives PG&E the opportunity to build a 21st century gas system for the citizens of California.[368]

Decision 11-06-017 provides a legal basis for establishing a retroactive effective date given that the Commissioned ordered PG&E to proceed with a specified scope of work to enhance gas safety on the transmission pipeline system, ordered PG&E to implement the safety enhancements through a PSEP "timeline for completion that is as soon as practicable," and directed PG&E to include a ratemaking proposal to address cost recovery for the PSEP work.[369]

C. Balancing Account

As part of its cost recovery approach, PG&E proposes that PSEP funds will be spent only on PSEP activities and not anything else, and that any unspent funds will be refunded to customers. In addition, for capital expenditures, only those capital projects which become operative will be charged to customers. Through this approach customers will pay only for the work performed.[370]

For expense, PG&E would recover in rates its forecast of annual expense; however, the forecast would be tracked in the balancing account and trued up to reflect actual expenses incurred each year as part of the AGT advice letter. This approach ensures that PG&E will only recover in rates its actual costs—any forecasted dollars that are not spent would be returned to customers, with interest, at the end of Phase 1. This approach for capital spending and expense eliminates any potential under traditional ratemaking for PG&E to receive funding for capital projects or expense activities that are not completed. The approach would also preclude reallocation of funds earmarked for the Implementation Plan to other utility uses.[371]

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[368] Ex. 21, PG&E Rebuttal, p. 1-30, l. 3-11.

[369] There is also a statutory basis for establishment of the memorandum account. Public Utilities Code Section 957(b) requires the Commission to authorize cost recovery in rates for all reasonably incurred costs for implementation of the adopted automated or remote control shut-off valves program. Public Utilities Code Section 961(b)(1) requires the Commission to provide "adequate funding" of the gas safety plan, of which the PSEP is a critical component. In order to implement the cost recovery provisions of these statutes, approval of the memorandum account is required.

[370] Ex. 21, PG&E Rebuttal, pp. 17-14—17-15.

[371] Ex. 2, PG&E Direct, p. 1-19, lines 3-13.

This element of PG&E's proposal eliminates any risk to customers that PG&E's cost forecast or contingency is too high. Unlike the ratemaking applicable in a typical general rate case, PG&E is not proposing to set rates based on its forecasted costs. If actual costs of a project are lower than expected, customers will only be charged for the actual, lower cost of the project. Customers will never be charged for estimates that are higher than actual costs or unneeded contingency funds.[372]

D. Tier 3 Advice Letter Process

PG&E requests that the Commission authorize PG&E to use a tier 3 advice letter process for expedited review of a request to change the approved forecasts for PSEP Phase 1. Under this process, if circumstances lead to a change in Phase 1 project scope, schedule or cost that would cause the program to exceed the Phase 1 forecast for expense or capital, PG&E would be required to submit an advice letter to the CPUC requesting a change in the project forecast. The public and interested parties would have an opportunity to comment on such a request. If the Commission decides not to modify the forecast in response to a request, PG&E would be required to manage and prioritize the remaining work scope within the approved forecast, potentially resulting in a shift of some projects to Phase 2 of the program.[373]

PG&E's proposed Tier 3 advice letter establishes a transparent process whereby PG&E can request recovery of additional costs required to complete Phase 1 work. Under PG&E's proposal, the advice letter submittal will describe the work that can be completed within the adopted forecast, the changed circumstances that have caused PG&E to propose to modify work scope, schedule or costs, and the additional costs that PG&E seeks to recover in rates to complete remaining Phase 1 work or other work ordered by the Commission. In order to address the possibility that a request for additional funding would be modified or denied, PG&E would also specify in the advice letter how it would adjust work scope to manage the remaining Phase 1

[372] Ex. 21, PG&E Rebuttal, p. 1-25, lines 22-28.

[373] Ex. 2, PG&E Direct, p. 1-18, lines 18-27.

work scope within the authorized budget for the project. The proposal therefore provides a platform for Commission review of potential mid-course corrections to the Phase 1 work scope. This allows the Commission to provide direction as unanticipated events arise, rather than wait and evaluate PG&E's response on an after the fact basis when it is too late to influence the outcome.[374]

Any request for recovery of costs above the approved Phase 1 forecast will require a resolution and approval by the Commission, as defined in General Order (GO) 96 B, Rule 7.6.2. Prior to Commission resolution and approval thereof, parties may protest or respond to an advice letter per GO 96 B, Rule 7.4.1. If approved, any increase in Phase 1 costs would be limited to the amount set forth by the Commission. PG&E will, therefore, have to demonstrate the reasonableness of its request in the advice letter. Parties will have an opportunity to review PG&E's submittal, probe the reasonableness of the request, provide a written response, and if necessary, ask the Commission to set an evidentiary hearing or other procedure for further review of the request. PG&E has recommended an advice letter process rather than an application for the simple reason that for the mechanism to be an effective means of providing real time input on how PG&E should respond to changed circumstances, it must be timely and requires an expedited Commission process.

PG&E's proposal presents a process for asking to increase the revenue requirement for Phase 1, but by no means provides a "guarantee." PG&E will have to prove its request is reasonable.

E. It Is Appropriate To Capitalize Pipe Replacements Less Than 50 Feet Long

PG&E has classified all pipeline replacement projects under the PSEP as capital expenditures. This is a change from PG&E's current practice of expensing replacement of

[374] Additionally, PG&E's proposed semi-annual progress reporting provides further clarity on the work being performed and cost. If it is necessary to move projects from Phase 1 to Phase 2, the reasons will be discussed in the semi-annual reports and the Commission will have a means of evaluating changes in work scope and timing.

sections of pipe less than 50 feet long.[375] The proposal is reasonable because the pipeline replacement program proposed in the PSEP involves a single approved scope of work (*i.e.*, a systematic and programmatic approach). It does not make sense to adopt different accounting protocols for the same type of work within the approved program. This is in contrast to the accounting principles PG&E uses for normal day to day maintenance work under the GT&S Rate Case, where if a small (less than 50 foot long) replacement is required in the context of a larger maintenance project it is convenient to expense the minor replacement work rather than establish a new capital order for a small portion of the project. In contrast, in the context of the PSEP, there will be 186 miles of replacements in Phase 1 that will be managed at the program level. Every replacement is part of this capital project and no convenience is served by having two sets of accounting rules that apply to the same type of replacement work. Having two sets of accounting rules in place would be inefficient. In the context of the overall program it makes no sense to differentiate based upon an arbitrary 50 foot cut off.[376] Should the Commission not agree with this treatment, the cost of the less than 50 foot replacement projects would need to be added to the expense forecast request.[377]

X. PG&E'S PROPOSED RATE DESIGN FOR RECOVERING PSEP COSTS SHOULD BE ADOPTED

PG&E's proposal for recovering PSEP costs through rates is just and reasonable. Adopting PG&E's proposal would mean an increase of about $.05 per therm on average core customer bills.[378]

A. It Is Appropriate To Adopt The Cost Allocation Approved In Gas Accord V

PG&E's Backbone Transmission services are unbundled, meaning that PG&E does not currently collect Backbone Transmission costs through the end-use rates paid by noncore

[375] Ex. 21, PG&E Rebuttal, p. 17-16, line 22—p. 17-17, line 18.

[376] *Id.*

[377] Ex. 2, PG&E Direct, p. 8-9, lines 7-13.

[378] Ex. 3, 11/4/11 Errata to Prepared Testimony, p. 10-7, Table 10-3.

customers.[379] The portion of the Backbone Transmission revenue requirements attributed to core and noncore customers is determined in PG&E's GT&S Rate Cases.[380] The most recent apportionment of PG&E's Backbone Transmission revenue requirement between core and noncore customers was established in the Gas Accord V Settlement, approved by the Commission in Decision 11-04-031.[381] PG&E proposes to allocate its annual PSEP Backbone Transmission-related revenue requirements to core and noncore customers based on their annual percentages of Backbone Transmission revenue requirement responsibility established in the Gas Accord V Settlement.[382] Similarly, PG&E proposes to allocate its annual PSEP Local Transmission-related revenue requirements to core and noncore customers based on their annual percentages of Local Transmission revenue requirement responsibility established in the Gas Accord V Settlement, and its PSEP gas Storage-related revenue requirements to core and noncore customers based on their annual percentages of gas Storage revenue requirement responsibility established in the Gas Accord V Settlement.[383]

PG&E believes that the most fair and equitable approach to cost allocation for the PSEP is to adopt the cost allocation approved in Gas Accord V.[384] Adoption of the Gas Accord V cost allocation makes sense as an interim step until the next GT&S Rate Case, which will provide an opportunity for parties to address cost allocation on a holistic basis.[385]

NCIP proposes an alternative cost allocation methodology called the equal percent of authorized margin ("EPAM") methodology. NCIP's proposed EPAM methodology would shift more costs onto core customers, away from non-core customers.[386] Using the revenue

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[379] Ex. 2, PG&E Direct, p. 10-1, lines 20-22.

[380] Ex. 2, PG&E Direct, p. 10-2, lines 3-5.

[381] Ex. 2, PG&E Direct, p. 10-2, lines 5-9.

[382] Ex. 2, PG&E Direct, p. 10-2, lines 9-13.

[383] Ex. 2, PG&E Direct, p. 10-2, line 18—p. 10-3, line 21.

[384] Ex. 21, PG&E Rebuttal, p. 19-1, lines 22-24.

[385] Ex. 21, PG&E Rebuttal, p. 19-1, line 32—p. 19-2, line 2; Tr. (Blatter), p. 2013, lines 7-12.

[386] Ex. 21, PG&E Rebuttal, p. 19-1, lines 25-26.

requirements as proposed by PG&E in its August 26, 2011 PSEP filing, the result of using NCIP's proposed EPAM methodology would be to raise core residential rates in 2012 from $0.0513 per therm (August 26, 2011 proposal) to $0.06583 per therm (EPAM methodology).[387] NCIP attempts to justify use of its alternative methodology by focusing on the percentage increases in core and non-core rates. NCIP, however, ignores the fact that the gas transportation rates paid by noncore customers are quite a bit lower on a relative basis when compared with core gas transportation rates; therefore, the percentage increase for non-core customers is higher than the percentage increase for core customers.[388] In any event, PG&E's proposed PSEP rates for noncore customers are lower than PG&E's proposed PSEP rates for core customers.[389] Because cost allocation is a zero sum game, if NCIP's EPAM methodology is adopted, core customers would be required to pay more PSEP costs in rates.[390]

B. The Commission Should Adopt PG&E's Proposal To Collect Pipeline Safety Enhancement Plan Costs Through A Separate Surcharge

PG&E proposes to recover its annual authorized PSEP revenue requirements for 2012-2014 through new Gas Pipeline Safety ("GPS") rate components included in the Customer Class Charges recovered in the end-use rates paid by PG&E's core and noncore customers.[391] The GPS rates will provide discrete PSEP rate components that can be used to accurately track recovery of PG&E's annual PSEP revenue requirements.[392] Under PG&E's proposal, all of PG&E's end-use customers will pay PSEP costs through the customer class charges included in PG&E's end-use gas transportation rates.[393] "End-use customer" can be defined as customers for whom PG&E delivers gas to the burner tip.[394]

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[387] Ex. 21, PG&E Rebuttal, pp. 19-4—19-5.

[388] Tr. (Blatter), p. 2008, line 22—p. 2009, line 1.

[389] Tr. (Blatter), p. 2021, lines 7-9.

[390] Ex. 21, PG&E Rebuttal, p. 19-1, lines 18-20.

[391] Ex. 2, PG&E Direct, p. 10-4, line 4—p. 10-5, line 1.

[392] Ex. 2, PG&E Direct, p. 10-5, lines 1-3.

[393] Ex. 21, PG&E Rebuttal, p. 19-7, lines 3-6.

[394] Tr. (Blatter), p. 2003, lines 19-23.

DRA claims that it is unreasonable for certain backbone customers to not pay for PSEP costs, and instead proposes to collect PSEP costs through the rates paid by shippers that subscribe to PG&E capacity.[395] PG&E's proposed surcharge on end-use customers is a more direct and transparent way to collect PSEP costs from PG&E's customers. For the most part, the customers served by shippers are PG&E's end-use customers. In 2011, 96 percent of total backbone transmission revenues and 99 percent of total storage revenues were ultimately paid by PG&E's end-use customers.[396] Instead of using shippers as middlemen to pass on PSEP costs to their customers, PG&E proposes to charge end-use customers directly.[397] In addition, DRA's proposed inclusion of PSEP costs in the GT&S rates paid by shippers would greatly reduce transparency for PG&E's customers, because PG&E would not be privy to the shippers' bills to their customers; neither the customer nor PG&E would know how the PSEP costs incurred by these shippers would be recovered from customers served by the shippers.[398] This could pose a problem. If, for example, a customer asked PG&E how much they were paying for PSEP costs and the customer was paying for those costs through the rates they were paying to their shipper, PG&E would be unable to provide that information.[399]

Finally, PG&E's proposal preserves several features of the Gas Accord V Settlement, including a negotiated Revenue Sharing Mechanism, negotiated discount adjustments and load factors, and a negotiated differential between backbone rates paid on the Baja and Redwood paths.[400] Therefore, PG&E requests that the Commission approve PG&E's proposal to collect PSEP costs through a separate, GPS surcharge on end-use customer rates.

[395] Ex. 149, DRA Direct (Sabino), p. 49, lines 1-10.

[396] Ex. 21, PG&E Rebuttal, p. 19-7, footnote 2.

[397] Ex. 21, PG&E Rebuttal, p. 19-7, line 17—p. 19-8, line 3.

[398] Ex. 21, PG&E Rebuttal, p. 19-9, line 19—p. 19-10, line 9.

[399] Tr. (Blatter), p. 1997, line 26—p. 1998, line 5.

[400] Ex. 21, PG&E Rebuttal, p. 19-8, line 4—p. 19-9, line 18.

XI. CONCLUSION

PG&E respectfully requests that the Commission approve the proposed scope of work for the Pipeline Safety Enhancement Plan, adopt the cost forecasts for performing the work planned for Phase 1, approve PG&E's proposed customer/shareholder cost sharing proposal, and allow PG&E to collect the approved costs through end-use customer rates.

Respectfully Submitted,

WILLIAM V. MANHEIM
KERRY C. KLEIN

By: *_/s/ Kerry C. Klein_*
KERRY C. KLEIN

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-3251
Facsimile: (415) 973-5520
E-Mail: KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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