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.	Rulemaking 11-02-019 (Filed February 24, 2011)

OPENING BRIEF OF THE UTILITY REFORM NETWORK ON THE PROPOSED PHASE 1 PIPELINE SAFETY ENHANCEMENT PLAN OF PACIFIC GAS AND ELECTRIC COMPANY (CORRECTED VERSION)

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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2. PG&E should hydrotest pipelines with manufacturing threats rather than defaulting to replacement. While TURN supports using the "30% SMYS" criterion to prioritize work, based on the likelihood of rupture versus leak, this is an inappropriate criterion to use to select between testing and replacement. Hydrostatic testing is appropriate for these pipelines to properly evaluate whether any identified manufacturing threat would cause a failure. Hydrotesting rather than replacing the 124 miles of pipeline with manufacturing threats reduces the capital cost forecast by $558 million and increases expenses by $62 million.
3. PG&E has included about 237 miles of pipeline for testing which is not required based on a lack of records, but is included for construction efficiencies. While TURN did not analyze each project, we share the concerns of the DRA that PG&E is including too much pipeline in Phase 1 that is not required based on the Commission's decision.
4. PG&E is proposing to strength test over 300 miles of pipeline operating at less than 30% SMYS, due to the absence of test records. TURN appreciates that this is responsive to the Commission's order. However, all experts agree that defects on such pipelines would fail as a leak, not a rupture. Federal regulations and industry standards appropriately differentiate pipelines operating at this pressure level. TURN recommends that the

Commission modify its order to allow for an exception to the testing requirement for pipelines operating below 30% SMYS.

5. Hydrotesting should be done to obtain test pressure levels of at least 90% SMYS. Industry standards and PG&E's own testing protocols require such pressure test levels. PG&E's low pressure testing is caused by the fact that is pipelines contain a patchwork of pipe with different strength characteristics, and thus different SMYS. PG&E claims that to perform sufficiently high pressure testing would require it to do too many small hydrotests, and would cost too much money.

<u>Valve Automation Program</u>

6. PG&E should install Automated Shut-off Valves ("ASVs") rather than Remote Control Valves on large diameter pipelines. The available evidence shows that an RCV will simply not be closed quickly enough to stop gas flow at a rupture within the 30-minute goal. PG&E's concerns about "false closure" are based on limiting assumptions concerning valve design and operation. PG&E admits that an ASV can be designed to operate without false closures.
7. PG&E should prioritize valve automation by targeting pipelines greater than 24-inches in diameter, rather than by using the Potential Impact Radius. Larger diameter pipelines emit higher heat flux.
8. PG&E should automate valves in Class 1 and 2 HCA areas containing identified sites. PG&E claims that this would be too expensive because there are 150 short and dispersed segments. TURN recommends that the Commission require PG&E to provide additional documentation and reporting on this issue.

<u>Gas Transmission Asset Management (GTAM)</u>

9. Using independent auditors retained by the Commission staff, the Commission should rigorously audit the GTAM project to ensure that it is meeting all objectives and requirements. In the event that the Commission determines (not until I.11-02-016 is concluded) that any GTAM costs are appropriate for rate recovery, no rate recovery should be allowed until the audit is concluded and made available to the parties for review and comment.

<u>Disallowances for Imprudence</u>

10. The Commission should disallow all PSEP Phase 1 costs from recovery in rates.
11. In the event the Commission does not order a full disallowance, it should order the following issue-by-issue disallowances (see the Table at the conclusion of the Summary of Recommendations for a quantification of these disallowances, to the extent possible at this time):
    a. The Commission should disallow all testing and replacement costs for PSEP pipeline installed after 1955.
    b. The Commission should disallow all testing and replacement costs for PSEP pipeline with identified manufacturing defects that was improperly assessed under Integrity Management requirements. At a minimum, the Commission should disallow all testing and replacement costs for pipeline with identified manufacturing defects for which PG&E spiked the pressure above MAOP.
    c. The Commission should disallow all testing and replacement costs for PSEP pipeline that was defective at the time of installation and should never have gone into service. This disallowance will need to be calculated after the PSEP pipeline

has been excavated and inspected, by qualified and independent inspectors, for such defects.

d. The Commission should disallow all or a portion of the costs of the 160 miles of pipeline PG&E failed to replace as part of its Gas Pipeline Replacement Program.

e. The Commission should disallow from rate recovery all costs of the MAOP Validation project.

f. The Commission should disallow from rate recovery all costs of the GTAM project.

12. Because the full record regarding the scope and extent of PG&E's imprudence and the effect of such imprudence on PSEP activities is still being developed in the enforcement proceedings (I.11-02-016, I.11-11-009, and I.12-01-007) and because those proceedings may order shareholders to pay for remedies that duplicate PSEP work, the Commission may not find that any PSEP costs are entitled to rate recovery until those enforcement proceedings are resolved. The Commission should schedule a future phase in this proceeding, after the records in the enforcement proceedings have closed, to receive further testimony and briefing regarding the cost responsibility issues.

13. The Commission should expand an already open investigation or open a new investigation to determine the full scope and extent of PG&E's violations of Integrity Management requirements.

<u>Other Ratemaking Adjustments</u>

See the Table at the end of this Summary of Recommendations for a quantification of these adjustments, to the extent possible at this time.

14. In the event that any PSEP capital costs are ultimately approved for rate recovery, the Commission should reduce the return on equity ("ROE") on such PSEP capital costs to PG&E's cost of debt, currently 6.05%. At a minimum, the Commission should adopt as an upper bound an ROE that is at the low end of the range of reasonable ROEs determined by the CPUC, currently 10.3%.
15. In the event that any recovery of PSEP costs is ultimately allowed, the following sources of funding should be used before ratepayer funding:
    a. Bonus depreciation pursuant to Resolution L-411;
    b. Earnings from PG&E's gas transmission and storage (GT&S) operations in excess of PG&E's authorized rate of return, calculated based on an earnings review as described in the testimony of TURN's witness, William Marcus (Exhibit 98);
    c. Funds equivalent to the amount paid for top manager and executive bonuses.
16. The Commission should: (1) remove from PSEP capital expenditures PG&E's costs for the Short-Term Incentive Program that are included in standard labor and corporate overheads and (2) remove from PSEP expenses costs for the Short-Term Incentive Program included in labor loaders.
17. The Commission should adopt a depreciable life of 65 years for PSEP pipeline replacements instead of the current 45-year period.
18. The Commission should allow further record development, based on the record in the enforcement proceedings, to determine the full extent of the following types of deferred maintenance by PG&E: (1) safety-related activities previously funded in rates but never carried out (double-dipping); (2) safety-related work that was done ineffectively and needs to be redone (such as PG&E's use of ECDA to assess manufacturing threats – at

least $70 million should be disallowed); (3) unreasonable deferral of necessary maintenance work (such as discontinuation of the GPRP and curtailment of ILI investment) that causes higher costs now. PG&E's cost recovery should be reduced for such deferred maintenance, using the methodology recommended by Mr. Marcus in Exhibit 98.

Other Ratemaking Issues

19. If the Commission does not disallow all PSEP costs now and does not adopt DRA's proposal to postpone all cost recovery to the next rate case, the Commission should consider approving a memorandum account to allow PG&E to track for potential future rate recovery PSEP costs PSEP costs incurred after the date of the decision.
20. TURN does not recommend any interim rate recovery for PG&E. However, in the event the Commission wishes to authorize an interim rate increase, the increase should be made subject to refund, and the amount of the increase should be only a fraction of PG&E's forecast costs to minimize revenue overcollections.
21. If the Commission allows any rate recovery, the Commission should reserve the possibility of conducting a future review to determine the reasonableness of PG&E's incurred costs for PSEP work. Such a reasonableness review would be in addition to the prudence review that has already begun in this proceeding.
22. The Commission should reject PG&E's proposal to allow it to defer work based on cost overruns. If PG&E is allowed to request additional rate recovery because of cost overruns, PG&E should be required to make such request by a petition for modification of the relevant Commission decision, and such petition proceeding should allow for discovery and evidentiary hearings as necessary.

23. If the Commission authorizes any cost recovery based on forecast costs, PG&E's forecast of AFUDC for expenses should be removed and its forecast of AFUDC for capital costs should be reduced, as described in the testimony of Mr. Marcus (Exhibit 98).
24. As discussed in Section 8.5, the Commission should require independent inspectors to assess the conditions of excavated pipeline and to ensure that PG&E is capturing all relevant information.
25. As discussed in Section 9.2, the Commission should direct PG&E to allocate any approved GTAM costs based on total pipeline mileage.

Summary Table of Proposed Disallowances and Reductions:

Basis for Disallowance or Reduction	**Mileage (if applicable)**	**Capital (1)**	**Expense (2)**
Non-Overlapping Reductions			
Pipeline Replacement for pipe installed post 1970	8.6	$38,700,000	
Hydrotesting Pipeline Installed 1961-70 with records missing	98		$49,000,000
Pipeline Replacement for pipe installed 1961-70	27	$121,500,000	
Hydrotesting pipeline installed 1956-1960	90		$45,000,000
Pipeline Replacement for pipe installed 1956-1960	18	$81,000,000	
Deferred Maintenance - Ineffective ECDA (2004-2010)			$70,000,000
Imprudent Integrity Management - failure to test pipe for MT installed pre-1956	177		$88,500,000
Imprudent Integrity Management - failure to test pipe for MT installed pre-1956	42	$189,000,000	
Disallow MAOP Validation costs Disallow GTAM costs ROE reduction to 6.05% or 10.3% (3)		 $95,200,000	$59,700,000 $20,500,000
TOTAL		**$525,400,000**	**$332,700,000**
Potentially Overlapping Reductions			
Deferred Maintenance due to termination of GPRP (30% of 160 miles)	160	$216,000,000	
Pressure Spiking (subset of IM)	31.9		$15,950,000
Pressure Spiking (subset of IM)	19.8	$89,100,000	
Imprudent IM - Failure to Test pipe with MT (includes all pipe)	239		$119,500,000
Imprudent IM - Failure to Test pipe with MT (includes all pipe)	62	$279,000,000	
GPRP Imprudence	160	$720,000,000	
Notes:			
1 - Use avg capital cost of $4.5 million/mile			
2 - Use avg hydrotest cost of $0.5 million/mile			
3 - Impact depends on amount of total approved PSEP capital costs			

OPENING BRIEF OF THE UTILITY REFORM NETWORK

1 Introduction and Executive Summary

The Utility Reform Network ("TURN") submits this opening brief regarding the Phase One Pipeline Safety Enhancement Program ("PSEP") of Pacific Gas and Electric Company ("PG&E").[1] In this phase of its PSEP, PG&E proposes to: pressure test, replace, or retrofit 1,168 miles of gas transmission pipeline; automate 228 gas shut-off valves; and carry out two major efforts to reform its pipeline record-keeping. PG&E forecasts total costs of $2.2 billion for this work.[2]

PG&E's PSEP is an outgrowth of one of the most lethal and destructive utility accidents in California history. On September 9, 2010, in a residential neighborhood in San Bruno, California, a portion of underground PG&E gas transmission Line 132 suddenly ruptured and exploded, causing the death of eight people, the total destruction of 38 homes and damage to another 70 homes.

In the wake of that disaster, two separate reviewing bodies – the National Transportation Safety Board ("NTSB") and an Independent Review Panel ("IRP") have issued extensive reports regarding the root causes of the accident and steps that should be taken to prevent such a tragedy from happening again.[3] Both reports found that a variety of serious mistakes and omissions by

[1] By e-mail dated May 12, 2012, Administrative Law Judge ("ALJ") Bushey granted TURN's request to file this brief one day late, on May 15, 2012.
[2] PG&E also indicates a future intent to submit a Phase 2 PSEP, in which costs may run as high as $9 billion. Exhibit (Ex.) 121 (TURN Opening Testimony/Long), p. 8.
[3] National Transportation Safety Board, *Pipeline Accident Report, Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010*, adopted August 30, 2011 ("NTSB Report"); *Report of the Independent Review Panel, San Bruno Explosion*, Prepared for California Public Utilities Commission, revised copy, June 24, 2011 ("IRP Report").

PG&E occurring over several decades contributed to the disaster. They included: inaccurate, missing and incomplete records; pressure tests and pipeline assessments that should have been done that were never carried out; and negligent oversight of pipeline construction and installation.[4] The reports found that these failures were the result of systemic management problems at PG&E. The NTSB concluded that the San Bruno pipeline rupture was an "organizational accident" and that the "multiple and recurring deficiencies" in PG&E's operations reflect a "systemic problem."[5] The IRP found that PG&E's top management was focused on financial performance and corporate image and insufficiently attentive to public safety; this corporate culture contributed to the serious failings in PG&E's operation of its gas transmission system.[6]

PG&E knows that California public utilities law does not allow a utility to require its customer to pay to fix its mistakes. This is a basic principle embodied in California Public Utilities Code Sections 451 and 463;[7] in public utilities law, this is known as the prudence requirement. Notwithstanding the deep-rooted and systemic safety problems identified by the NTSB and IRP, PG&E desperately tries to argue that the PSEP is not remedial in nature. Instead, PG&E contends that it should be allowed to recover in increased gas rates almost 85 percent of the $2.2 billion of forecast PSEP costs because almost all of the activities it will undertake are in response to new safety standards imposed by the Commission in Decision (D.)

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[4] NTSB Report, pp. 108-110, 116-118; IRP Report, pp. 7-13.
[5] NTSB Report, pp. 116-117.
[6] IRP Report, pp. 16-17, 48, 52-53.
[7] All statutory references are to the California Public Utilities Code, unless otherwise indicated.

11-06-017.[8] PG&E goes so far as to argue that, if D.11-06-017 had never been issued, it would not need to carry out most of the PSEP activities.

PG&E's argument is simply not credible in light of the wide-ranging and longstanding pipeline safety mismanagement that the NTSB and IRP Reports have already brought to light. Perhaps the best proof of the remedial nature of the PSEP is the scope of work that PG&E announced it would do in its "Pipeline 2020" program, long before the CPUC issued D.11-06-017. The record shows that Pipeline 2020 would have carried out the same pipeline and valve programs as PG&E's PSEP, in order to address issues that PG&E identified after the San Bruno explosion. Pipeline 2020 is thus a clear indication that the PSEP is needed to meet PG&E's basic safety obligations and not to satisfy supposedly new standards announced in D.11-06-017. Similarly, the pipeline record programs in the PSEP -- the MAOP Validation project and the Gas Transmission Asset Management ("GTAM") project are needed to rectify PG&E's complete and deep-seated failure to put systems and processes in place to ensure that the company has the accurate, complete and accessible pipeline records it needs to safely operate its gas transmission system.

PG&E has not met, and cannot meet, its burden of showing that the PSEP work is not remedial in nature. Accordingly, all of the costs of PG&E's Phase 1 PSEP should be disallowed from rate recovery and should be borne by shareholders. If this seems like a harsh result, the Commission should re-read the NTSB and IRP Reports and ask the question of whether a company in a competitive sector of the economy that so fundamentally mismanaged its

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[8] This percentage would likely be less than 5% if one considers the amortized revenue requirements including utility profits and taxes. Oddly enough, PG&E did not provide a forecast of full recovery over the life of the assets, but a conservative approximation would be at least $5 billion, given the level of capital investment and a 45-year useful life.

operations and misperceived its priorities would even be able to survive in the marketplace. Under the circumstances, a full disallowance of the PSEP costs is entirely justified and compelled by the law and the facts.

In the event that the Commission is not ready to order a full disallowance at this time, TURN presents a meticulous program-by-program and issue-by-issue assessment of the work in the PSEP that the record shows to be remedial in nature and thus ineligible for cost recovery under the law. In addition, TURN presents other ratemaking options, including recommendations for return on equity ("ROE") adjustments, that the Commission can use in order to arrive at a fair apportionment of PSEP costs between shareholders and ratepayers. In addition, in an effort to ensure that the PSEP focuses on the necessary work to make PG&E's gas transmission system safe, TURN proposes several changes to the scope and nature of the proposed work in the PSEP. TURN's full set of recommendations on all of these issues can be found in its Summary of Recommendations.

2 Summary of Argument

2.1 Background

As one of a series of decisions responding to the San Bruno disaster, the Commission in Decision (D.) 11-06-017 ordered PG&E and the other California gas utilities to submit Implementation Plans to ensure the safety of their gas transmission pipelines. The Implementation Plans were required to provide for the "orderly and cost effective" testing or replacement of all transmission pipeline segments that have not previously been pressure tested. In response to this order, PG&E submitted its PSEP, consisting of three major program areas: Pipeline Modernization, Valve Automation, and a Pipeline Records Integration Program. Based on PG&E's estimated scope and costs for the activities in these programs, PG&E forecasts a total program cost of $2.2 billion. Of that total, PG&E proposes that shareholders would be responsible for no more than $370 million,[9] and the remainder should be recovered from PG&E's customers in gas rate increases.

PG&E's PSEP presents two main categories of issues for the Commission's resolution: (1) Scope of Work – i.e., does the PSEP include the appropriate activities and are they prioritized correctly? and (2) Costs and Rates – i.e., what costs, if any, should be recovered from ratepayers?

2.2 Summary of TURN's Analysis of Scope of Work Issues

2.2.1 Pipeline Modernization Program

2.2.1.1 PG&E's Proposal Is Both Over-Inclusive and Under-Inclusive

The Commission ordered PG&E to test or replace all pipelines that were not pressure tested or lack sufficient records of a historical pressure test. The Commission directed the utilities to achieve this goal "as soon as practicable," but the Commission also instructed the utilities to start with pipeline segments located in high consequence areas ("HCA").[10]

In response, PG&E put forth its Pipeline Modernization Program, which includes testing 783 miles and replacing 185 miles of pipeline, significantly over the 630 miles of HCA pipelines without complete records. PG&E's proposal is both overinclusive, by targeting pipelines located in Class 2 non-HCA areas and incorporating additional mileage for efficiencies; and underinclusive, by not targeting pipelines in Class 3 locations that operate at pressures below the

[9] Tr., vol. 8, p. 839:2-8 (Bottorff/PG&E).
[10] The Commission essentially specified using method 1 to define an HCA, thus including all Class 3 and 4 locations and Class 1 and 2 HCAs. 49 CFR 192.903.

threshold hoop stress of 30% of specified minimum yield strength. PG&E also selected pipelines using their old GIS system data, and PG&E plans to refine their projects based on the results of the MAOP Validation work as part of design engineering.

2.2.1.2 PG&E's Decision Tree Inappropriately Makes Replacement a Default Step

PG&E used a "decision tree" process that evaluated pipeline segments based on the categories of threats outlined in federal integrity management regulations and incorporated industry standards. Additionally, PG&E used the 30% SMYS criteria and class location to determine whether to test a segment, replace it or defer it to phase 2.With respect to the decision tree logic and PG&E's choice to test or replace, TURN's primary concern is that PG&E is defaulting to expensive and unnecessary pipeline replacement in situations where testing would be a sufficient and safe outcome. Specifically, PG&E has slated over 120 miles of pipeline for replacement due to the existence of manufacturing threats, with a capital cost of $540 million. But most of these pipelines could reasonably be hydrostatically tested to properly evaluate whether any such threat would cause a failure.

TURN recommends that the process should be reversed. PG&E should test these pipelines, and should replace them only if it has specific justifications that warrant replacement. The Commission ordered PG&E to set forth criteria to explain a decision to replace instead of pressure testing. PG&E's direct showing provided no explanation of why PG&E defaulted to replacement based on the 30% SMYS criterion, and PG&E's subsequent explanations boiled down to an assertion that these pipes are "old." The Commission should not allow PG&E to make a choice that impacts more than $500 million in capital costs based on an explanation that occupies less than a page of PG&E's multi-volume showing.

2.2.1.3 PG&E's Testing Program Would Test More Pipeline Miles Than Necessary and Uses Inadequate Testing Procedures

TURN's fundamental recommendation with respect to pipeline testing is twofold: that it is better to do less, and do it right. PG&E's program encompasses considerable mileage for testing and replacement that may not need to be tested or replaced. PG&E's actual hydrotest procedures are not adequate and may give a false sense of security.

PG&E has included about 237 miles of pipeline for testing which are not required based on a lack of records, but are included for construction efficiencies. While TURN did not analyze this issue on a project-by-project basis, we share the concerns of the DRA that PG&E is including too much pipeline in Phase 1 that is not required based on need.

Furthermore, PG&E is proposing to strength test over 300 miles of pipeline operating at less than 30% SMYS, due to the absence of test records. TURN appreciates that this is responsive to the Commission's order. However, all experts agree that defects on such pipelines would fail as a leak, not a rupture. TURN recommends that the Commission modify its order to allow for an exception to the testing requirement for pipelines operating below 30% SMYS.

Most importantly, TURN strongly recommends that hydrotesting be conducted at pressure levels of at least 90% SMYS. Industry standards and PG&E's own testing protocols require such pressure test levels. But PG&E has chosen to use lower pressures as long as the test pressure to MAOP ratio is sufficient. While the ratio of test pressure to MAOP is quite important, it is only through the high pressure hydrotest at 90% of SMYS that potential failures can be detected with certainty. Low pressure hydrotesting may result in a false sense of security, and may result in a waste of ratepayer money on ineffective hydrotesting. PG&E's low pressure testing is caused by the fact that is pipelines contain a patchwork of pipe with different strength characteristics, and thus different SMYS. PG&E claims that to perform sufficiently high pressure testing would require it to do too many small hydrotests, and would cost too much money. The Commission should not accept this explanation without close scrutiny of alternatives.

2.2.2 Valve Automation Program

2.2.2.1 The Commission Should Direct PG&E to Rely on Automated Shut-Off Valves Rather than Remote Control Valves

PG&E intends to install remote control valves (RCVs) on pipelines based primarily on using the Potential Impact Radius ("PIR") as a selection criterion. TURN has two primary concerns regarding PG&E's plan.

First, TURN strongly recommends that the Commission order PG&E to rely on Automated Shut-off Valves ("ASVs") rather than RCVs. The available evidence shows that an RCV will not be closed quickly enough to stop gas flow after a rupture within the 30 minute goal for gas shut off. PG&E relies on the expectation that in the future a control room operator will be able to respond within 15 minutes of a rupture to initiate closing a valve. PG&E provides no evidence to support this expectation, and real world data indicate that such short response times are highly optimistic. PG&E also incorrectly calculates the time it takes for gas to be expelled from the pipeline after valves are closed, thereby further underestimating the time it will take to close off gas flow.

PG&E opposes the use of ASVs based on the industry concern of false closure. But PG&E admits that ASVs can be designed to eliminate this problem. TURN shows that PG&E's reluctance reflects long-standing industry bias against valve automation, rather than actual technical challenges.

In order to meet a 30-minute response time in the event of any future rupture, the Commission should order PG&E to automate its valves using sophisticated monitoring and control logic in ASV mode.

2.2.2.2 PG&E Does Not Prioritize the Right Pipelines for Automation

Second, TURN is concerned that PG&E's prioritization focuses on the wrong criterion, and neglects critical Class 1 and 2 HCA areas. TURN's witness explains why pipeline diameter is more critical than the Potential Impact Radius, because of the higher heat flux emitted by large diameter pipelines. While PG&E claims that in practice the results are similar, the data are contradictory on this issue.

PG&E also claims that it would be too expensive to automate Class 1 and 2 HCA areas, because the there are 150 short and dispersed segments. TURN recommends that the Commission require PG&E to provide additional documentation and reporting on this issue.

2.2.3 Cost Forecasting

TURN's limited resources did not allow it to submit much testimony concerning PG&E's cost estimates. TURN's witness testified that PG&E's hydrotest cost forecasts were significantly higher than costs he had experienced in the past, or than published costs. TURN notes that DRA provided significant testimony concerning cost forecasts and contingencies. In any case, TURN strongly recommends against deeming any costs "reasonable" based on PG&E's forecasts.

2.3 Summary of TURN's Analysis of Cost and Rate Issues

TURN focused significant attention on cost responsibility – how PSEP costs should be allocated between PG&E's shareholders and ratepayers. Cost responsibility in turn breaks down into two issues: (1) What disallowances are required because of PG&E's imprudent management of its transmission pipeline system? and (2) What other disallowances are appropriate? TURN presents a thorough analysis of both of these issues.

2.3.1 The Commission Must Disallow Any PSEP Costs for Work That Remedies PG&E's Mistakes

It is a bedrock principle of California public utilities law, embodied in Sections 451 and 463 that utilities may not recover from their ratepayers costs that result from the utilities' imprudence. Section 463 is clear that the Commission "shall disallow" such costs from rates. The prudence requirement serves the important purpose of substituting for absent competitive forces, imposing on monopoly utilities a necessary deterrent against imprudent conduct. As the operator of pipelines transporting potentially explosive natural gas, PG&E must be held to a high standard of prudence. To meet its prudence obligations, PG&E must at least meet accepted industry standards, such as such as the American Society of Mechanical Engineers ("ASME") ASA B31.8 standards for gas pipeline construction, operation and maintenance. PG&E has the burden of proof to show that its conduct was prudent. Under Section 463, if PG&E's missing records prevent the Commission from assessing whether PSEP work is remedial, the Commission is required to disallow such costs.

PG&E recognized these principles to an extent. PG&E conceded that it should not be allowed to recover costs for PSEP activities that are necessary to comply with a "preexisting regulatory requirement," but PG&E took an improperly narrow view of this term. Prudent and safe operation of its pipeline system has always been part of PG&E's regulatory obligations under Sections 451 and 463. Accordingly, the Commission must disallow any PSEP costs that are needed to remedy PG&E's imprudence. Put another way, if PG&E's prudence obligations required the company to do work even if D.11-06-017 had never been issued, the costs of such work may not be recovered from ratepayers.

2.3.2 All of the PSEP Costs Should Be Disallowed from Rate Recovery

As discussed above, all of the PSEP programs and activities are needed to remedy the serious and pervasive mismanagement of PG&E's gas transmission system. For this reason, all PSEP costs should be disallowed from rate recovery.

Contrary to PG&E's claim, the determination in D.11-06-017 that California gas utilities may no longer rely on the "grandfathering" provision of federal regulations to establish MAOP of pre-1970 pipeline segments does not alter this conclusion. Federal regulations only establish minimum requirements. PG&E has always been obligated under Sections 451 and 463 to operate its pipelines at safe operating pressures and to be able to document that safety margin in reliable records readily available to itself and its regulators. After the San Bruno explosion, PG&E was unable to demonstrate that it had set the MAOP of its pipelines at safe levels. The PSEP, like PG&E's Pipeline 2020 proposal, is designed to remedy this serious failing, and its costs should not be imposed on ratepayers.

2.3.3 Issue-by-Issue Application of Prudence Principles to PSEP Activities

If the Commission decides at this time not to disallow all PSEP costs, it should consider the many reasons to disallow significant portions of those costs. TURN's analysis responds to the ALJ's request for parties to be as specific and detailed as possible in recommending disallowances for imprudence.

2.3.3.1 Testing and Replacement Costs for Any 1955 or Later Pipeline Segments in the PSEP Should Be Disallowed

Since 1955, ASA B31.8 industry standards have specified that newly installed pipeline must be strength tested before the pipeline could go into service and that records of such pressure tests must be preserved. Beginning in 1961, these standards were adopted in General Order ("GO") 112. Much of the PSEP work would require testing or replacement of pipeline installed in 1955 or later because PG&E failed to create or retain the required test records. Because this work is necessary to remedy PG&E's failure to meet industry standards and Commission requirements, the costs of this work should be disallowed. The PSEP includes approximately 58.37 miles (replacement) and 277.6 miles (hydrotesting) of pipeline installed after 1955, resulting in an approximate total disallowance of $262.7 million in capital costs and $138.8 million in expenses.[11]

2.3.3.2 Testing and Replacement Costs for Pipelines That Were Inappropriately Assessed Under Integrity Management Requirements Should Be Disallowed

Under Integrity Management requirements, PG&E likely used the wrong method for assessing manufacturing threats for approximately 300 miles of pipeline included in the PSEP. PG&E's inclusion of these 300 miles in the PSEP is made necessary by PG&E's violation of Integrity Management ("IM") requirements. As a result, the Commission should disallow about $120 million in hydrotest expenses and $279 million in costs for pipeline replacements.

There is another reason to disallow PSEP costs for a subset of the 300 miles with manufacturing threats. In violation of IM requirements, PG&E failed to hydrotest pipelines with identified manufacturing threats for which PG&E spiked the pressure above MAOP. Because

[11] These numbers include some pipeline installed post 1970, for which PG&E has admitted responsibility for only the hydrotesting costs, and has miscalculated that number.

this pipeline was not hydrotested, it now needs to be included in the PSEP. TURN estimates that this violation affects approximately 52 miles of pipeline included in the PSEP for testing or replacement. Thus, if the Commission does not apply the larger disallowance for the 300 miles, the CPUC should at least disallow testing expenses of about $16 million and pipeline replacement capital costs of about $144 million, for these 52 miles of pipeline.

2.3.3.3 Testing or Replacement Costs for Defective Pipeline Segments That Should Never Have Gone Into Service Should Be Disallowed

The NTSB Report found that Segment 180 of Pipeline 132 was defective at the time of installation and that "inadequate quality control" by PG&E allowed the segment to go into service. Given the systemic nature of PG&E's quality control problems, there is every reason to believe that PG&E imprudently allowed other defective pipe segments to be placed into service. Ratepayers may not be required to pay to test or replace pipe segments that should never have gone into service. Such a determination cannot be made until pipe is excavated. TURN recommends that qualified independent inspectors be present at all PSEP pipeline excavations to determine whether the pipeline had defects that should have been detected at the time of installation. Thus, until the Pipeline Modernization program is concluded, it will not be possible to quantify the disallowance for this element of PG&E's imprudence.

2.3.3.4 The MAOP Validation Project Is Remedial and Its Costs Should Be Disallowed in Full

In PG&E's case, the main reason for the MAOP Validation project is to remedy the serious problem that an unknown number of PG&E's pipeline records are inaccurate. PG&E's inaccurate pipeline features records regarding Line 132 contributed to the San Bruno disaster, and the Commission wisely ordered PG&E to gather all of its pipeline features data and to ensure that it is accurate and reliable. Moreover, MAOP validation using pipeline features is work that PG&E should have done all along to meet the prudence standard for a pipeline operator transporting a potentially explosive gas. PG&E's claim that "traceable, verifiable, and complete" is a new standard ignores the fact that a prudent utility would have satisfied this standard from the time it began transporting natural gas.

2.3.3.5 PG&E Has Failed to Meet Its Burden of Showing That GTAM Costs Are Entitled to Recovery

Although PG&E claims that GTAM costs are not remedial, it has not met its burden of proof. To the contrary, PG&E's written and oral testimony shows that GTAM is designed to remedy the deficient processes and systems discussed at length in the IRP Report and PG&E's own consultant report. If the Commission is not ready to disallow GTAM costs now, at a minimum the Commission must refrain from authorizing rate recovery of any GTAM costs until the Commission has developed a full record on PG&E's information management practices in the Record-Keeping OII (I.11-02-016).

2.3.4 The Commission May Not Find That Any of the PSEP Costs Are Entitled to Rate Recovery Until the OIIs Are Resolved

If the Commission does not find that all of the PSEP costs should be disallowed, it must refrain from making a final determination that any PSEP costs are entitled to rate recovery. The current record is far from complete on the full scope of PG&E's imprudence and the extent to which the PSEP is needed to remedy such imprudence. The three pipeline safety OIIs will examine PG&E's past pipeline management practices in much more depth and are sure to demonstrate more ways that the PSEP and its constituent elements are remedial in nature. Before final rate recovery for any PSEP costs can be allowed, at least two steps must happen: (1) the evidentiary record in each of the three OIIs has closed and parties in this docket have had an opportunity to present updated testimony and arguments about prudence and any other cost responsibility issues in a separate phase of this proceeding; and (2) in the OIIs, the Commission has determined the remedial measures that shareholders are required to fund and parties in this case have had an opportunity to provide argument about the impact of those adopted measures on the scope and cost of PSEP work.

2.3.5 Apart From Disallowances for Imprudence, Other Ratemaking Adjustments Are Appropriate to Reduce the Ratepayer Share of PSEP Costs

In addition to disallowances for imprudence, TURN proposes other ratemaking adjustments that would apply in the event that the Commission ultimately authorizes any PSEP rate recovery. Specifically:

- The Commission should reduce the return on equity ("ROE") on PSEP capital expenditures to the present cost of debt, or at minimum to the low end of the reasonable range of ROEs already authorized by the Commission;
- The Commission should remove amounts for incentive compensation from overheads applied to PSEP costs; and
- The Commission should order PG&E to first use certain internal sources of funding before raising rates, including: bonus funds from accelerated depreciation; overearnings in its gas transmission and storage ("GT&S") operations; and executive bonuses already included in rates.

All of these adjustments are warranted because of PG&E's past inadequate attention to safety and excessive focus on financial performance.

Additionally, TURN recommends that the Commission order PG&E to apply a longer 65-year depreciable life for transmission mains. Such a change is warranted based on available data and will simply result in a longer amortization of cost recovery, leading to reduced short term rate impacts.

Finally, TURN proposes a mechanism to incorporate any present or future findings regarding deferred maintenance – i.e., the postponement of necessary work resulting in future higher costs to ratepayers. Although the record suggests a variety of ways in which PG&E has deferred maintenance to the detriment of ratepayers, the record is now incomplete on the full extent of deferred maintenance and awaits further development in this or other proceedings.

3 Evaluation of the Pipeline Modernization Program

3.1 Summary of PG&E's Program Design Process and Decision Tree Outcomes

The Division of Ratepayer Advocates cogently summarized the process by which PG&E determined the scope of work for Phase 1 of the PSEP.[12] PG&E used its existing Geographic Information System ("GIS") database of just over 25,000 pipeline segments, which includes numerous fields defining the physical location of the segment, its class location, various physical characteristics of the pipeline, information concerning prior pressure tests, and the MAOP of the segment.

[12] Exh. 144, Sec. 4.1, p. 29-33, Roberts, DRA.

To this database, PG&E added a field which contains the preliminary results of its MAOP validation search for test records, as of the end of April 2011.[13] This field contained one of three possible entries (complete, incomplete, partial mileage) or was left blank. An additional field, labeled "Subpart J," contained a "Y" if evidence of a prior hydrotest showed that the test duration was greater than one hour.

PG&E used its decision tree logic to process each segment in the GIS database that was not "complete" or did not have a "subpart J" hydrotest entry of yes. This process assigned each segment lacking a "complete" record to one of the thirteen decision tree outcomes, as illustrated in Table 1:

Table 1: Decision Tree Outcomes for Replacement and Testing

Decision Tree	Decision Tree Outcome Step	Miles for Relacement	Miles for Testing
Manufacturing	M2	100	16
	M3	2	12
	M4	22	226
	M5	0	23
Subtotal		**124**	**277**
Fabrication	F2	14	13
& Construction	F3	2	0
Subtotal		**16**	**13**
Corrosion	C1	0	73
& Mechanical	C2	6	195
Damage	C3	9	93
	C4	15	46
	C5	2	13

[13] In the PSEP database and various data responses this field is identified as "MAOPrec430," meaning it was the MAOP field as updated on April 30, 2011. TURN uses the term "MAOP field" or "MAOP validation field" as a shorthand for this data field.

Decision Tree	Decision Tree Outcome Step	Miles for Relacement	Miles for Testing
	C6	7	41
	C7	6	32
Subtotal		**45**	**493**
TOTAL		**185**	**783**

Two important conclusions are evident from Table 1. First, a large portion of pipeline replacement – 122 out of 185 miles – is driven by the manufacturing threat decision tree and outcomes M2 and M4. Second, the largest drivers of the decision to hydrotest are outcomes M4 and the three corrosion threat outcomes (C1, C2 and C3).

PG&E then evaluated the segments and grouped segments, based on both location and additional criteria, into 168 replacement projects, 165 hydrotest projects and 8 ILI projects. These projects included approximately 344 miles of pipeline that was not required to be included in the decision tree, ostensibly so as to promote long-term construction efficiencies.

3.2 The Future Incorporation of the Results of MAOP Validation Will Likely Reduce the Phase 1 Scope of Work

The MAOP validation field was populated in April of 2011. PG&E has not globally updated this field to account for additional information collected during the 2011 MAOP validation process, which was completed by the end of August for HCA segments. Such a global update is apparently difficult, if not impossible, to perform because the MAOP validation effort inputs data into a new GIS system, the "Intrepid" system.[14] PG&E's plan is thus to update each project as part of the project engineering using the new GIS information.

Incorporation of the MAOP validation process into the PSEP results can only reduce forecast costs, since PG&E has located additional records that will reduce the amount of pipelines included in the PSEP. As part of the 2011 MAOP Validation, PG&E located complete test records for an additional 157 miles of pipeline in 2011.[15] Indeed, PG&E found complete records for 42.2 miles of the 152 miles of priority pipeline scheduled for hydrotesting in 2011, thus reducing the priority mileage that had to be hydrotested in 2011.[16]

Thus, should the Commission authorize any rate increase prior to a future reasonableness review, which TURN strongly opposes, it should at most include only a portion of PG&E's forecasts costs in rates at the outset. Actual costs should be tracled in a memorandum account for future reasonableness review.

3.3 There Is An Unresolved Issue Concerning the Impact of MAOP Validation

There are several data and definitional issues that are relevant for both safety and cost responsibility and need to be highlighted at the outset. The MAOP validation field in the old GIS sytem is populated by one of four possible inputs – complete, incomplete record, partial mileage, or a blank in the field. As part of its MAOP validation, PG&E intends to create an output with only two fields – complete and no test or missing records.

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[14] RT 1436, Hogenson; RT 1732 and 1739, Whelan. The IT situation is actually a bit more complicated, as explained by Mr. Whelan at RT 1732, lines 17-28.

[15] Compare 1018 (complete) in March 15, 2011 to 1175 (complete) in September 12, 2011. See, for example, Exh. 144, p. 23, Roberts, DRA. As of September 12, 2011, PG&E had a total of 630 miles of HCA pipelines without "complete" records.

[16] PG&E Status Report on Hydrostatic Pressure Testing, Filed on December 30, 2011 in R.11-02-019, p. 2.

Regrettably, there appears to be no clear definition or explanation of the meaning of a "blank record" in the existing MAOP validation data field. Mr. Singh, PG&E's primary witness on MAOP validation, did not know the meaning of a blank field in the PSEP database.[17] However, in assigning cost responsibility for hydrotesting 1961-1970 pipeline to shareholders, PG&E selected *only* those pipelines with an "incomplete record" in the MAOP field. There are a significant number of segments in the PSEP database that are labeled "partial mileage" or left blank. As discussed in relevant sections below, the cost for testing these segments should likewise be borne by PG&E shareholders.

3.4 Prioritization of Pipeline Testing and Replacement Work

3.4.1 The Prioritization of Work is Relevant to Safety and Cost

PG&E's gas transmission system consists of almost 6,000 miles of pipeline, including about 1800 in populated areas.[18] The Commission ordered PG&E to test or replace all pipelines that were not pressure tested or lack sufficient records of a historical pressure test. The Commission directed the utilities to achieve this goal "as soon as practicable," and the Commission directed PG&E to "start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and 2 high consequence areas."[19]

PG&E has identified about 630 miles of HCA pipeline as lacking adequate records of prior hydrotests.[20] PG&E has not provided any estimates of how many non-HCA pipeline miles

[17] RT 1639 and 1642, Singh, PG&E.
[18] TURN uses the shorthand "populated areas" to refer to "Class 3 and 4 and HCA Class 1 and 2." We do not address at this time the issue of how PG&E has historically classified HCA pipeline.
[19] D.11-06-017, *mimeo.* at 19-20 and Ordering Paragraph 4, p. 31.
[20] See, for example, Exh. 144, p. 23, Roberts, DRA (reproducing data from PG&E 2011 status reports on MAOP validation).

lack hydrotest records, though PG&E has estimated post Phase 1 work would cost between $6.2 and $9 billion.

A crucial question is how to prioritize the work so as to ensure system safety while minimizing costs due to work stress and appropriately amortizing costs. PG&E testified that including all segments in HCA locations "represents far too large a work scope for PG&E to accomplish in a 4-year period (2011-2014) in Phase 1."[21] PG&E selected a four-year period for Phase 1 primarily to align the next phase with its rate case cycle.[22]

Instead, PG&E included in Phase 1 those segments in populated areas that operate at pressures greater than 30% SMYS, or those segments with an identified manufacturing threat that operate at greater than 20% SMYS. However, PG&E also included segments in Class 2 for prioritization in Phase 1. Together with adjoining segments selected for construction efficiency, PG&E's Pipeline Modernization Program includes 783 miles for testing and 185 miles for replacing, significantly over the 630 miles of HCA pipelines without complete records. PG&E's proposal is both overinclusive, by targeting pipelines located in Class 2 non-HCA areas; and underinclusive, by not targeting pipelines in Class 3 locations that operate at pressures below the threshold hoop stress of 30% of specified minimum yield strength. PG&E also selected pipelines using their old GIS system data, and PG&E plans to refine their projects based on the results of the MAOP Validation work as part of design engineering.

TURN supports many of the analyses and recommendations provided by the Division of Ratepayer Advocates ("DRA") and the City and County of San Francisco ("CCSF") concerning work prioritization. The DRA concluded that PG&E's Phase 1 includes over 400 miles (71.5

[21] Exh. 1, p. 3-37:9-11, Hogenson, PG&E.
[22] 12 RT 1593, Hogenson, PG&E.

miles for replacement, 333.7 miles for testing) that do not fit PG&E's own priority criteria; and PG&E's Phase 1 does not include about 60 miles (47.6 for replacement, 14.1 for testing) that should be included.[23]

DRA does not disagree that some additional mileage will be tested or replaced for construction efficiencies. The DRA closely analyzed several of the projects proposed by PG&E and concluded that some of the additions were unwarranted.[24]

TURN has not independently analyzed the issue of including over 300 miles of non-priority pipeline for construction efficiency. It is basically impossible for intervenors to perform the type of detailed project review for the approximately 330 projects included in PG&E's Phase 1 within the timeframe of this proceeding. TURN was pleased to see that CPSD performed a random analysis of a few such projects as part of its evaluation of the Sempra plan. CPSD did not perform such an evaluation of any projects in the PG&E plan.

3.4.2 PG&E Should Not Target Work in Class 2 Locations

The PG&E Decision Tree Steps 1L, 1K, 2G, & 3B include class 2 location areas in the filtering analysis. Approximately 10% (580 miles) of PG&E's transmission lines are in Class 2 locations, but only about 30 miles of Class 2 pipeline contain HCAs.[25] PG&E's PSEP includes over 40 miles of Class 2 for replacement, or fully 22% of the replacement miles.[26] PG&E's PSEP includes over 157 miles of Class 2 for testing, or about 20% of the testing miles.

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[23] Exh. 144, p. 42-43 and Table 6, Roberts, DRA.
[24] Exh. 144, p. 55, Roberts, DRA and Exh. 147, p. 19-29, Scholz, DRA. The CCSF likewise pointed out the inclusion of excessive amounts of non-priority pipeline on Line 108. Exh. 137, p. 72, Radigan, CCSF.
[25] Exh. 131, Table 5, p. 15, Kuprewicz, TURN.
[26] Exh. 131, Table 4, p. 12, Kuprewicz, TURN.

In its direct testimony PG&E justifies the inclusion of Class 2 pipe with two sentences: "The CPUC's Consumer Protection and Safety Division specifically asked that PG&E keep a consistent use of Class 2 in the Phase 1 work scope, Decision Tree box 1L. While this represents a significant increase in Phase 1 work scope, PG&E has incorporated this suggestion into its Implementation Plan." This explanation is neither clear nor defensible at this time. It does not even allege that CPSD requested that Class 2 pipeline be included in Phase 1.[27]

Class 2 locations should be removed from the 1L, 1K, 2G, & 3B decision/evaluation points until PG&E can properly explain or justify the threat basis for including Class 2 locations. Phase 1 efforts should rightly focus on the highest populated areas and higher risk pipelines first. PG&E agrees that work in Class 2 locations does not fall into the "urgent category."[28]

There may be small segments of class 2 pipeline segments that might warrant incorporation into the Phase 1 PM effort for project efficiency. Unfortunately, PG&E has not provided data or information differentiating how many Class 2 segments were included for efficiency versus because PG&E made an affirmative choice to include *all* of Class 2 pipeline in their decision tree. TURN recommends that Class 2 segments should be included only due to operational efficiencies or based on their realistic near future (Phase 1 - 2012 through 2014) potential to become HCAs.

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[27] Since CPSD is not a party in this rulemaking, they could not be questioned concerning this statement. The CPSD Technical Report (December 23, 2011) on PG&E's plan consists of less than one page on pipeline modernization and does not opine on prioritization at all. The Jacobs Consultancy Report likewise offers no opinions on prioritization, though its discussion of PG&E's proposal does not appear consistent with PG&E's testimony: "Pipe that operates below 30 percent of SMYS in a populated areas will be strength tested and rural piping will be checked for fatigue cracks in Phase 1 and strength tested in Phase 2." Jacobs Consultancy, December 23, 2011, p. 22.

[28] 12 RT 1594-1596, Hogenson, PG&E.

Assuming that only 10% of the Class 2 location work is necessary for project efficiency, TURN's recommendation would lead to a cost reduction of about $162 million for replacement[29] and $70.7 million for testing,[30] for a total savings of approximately $232.7 million. Alternatively, the Commission should require PG&E to provide an advice letter substantiating which Class 2 locations are included only due to operational efficiencies.

3.4.3 Prioritization Using the 30% SMYS Criterion May Be Appropriate, But Choosing to Test or Replace Based on This Criterion is Not Appropriate

PG&E uses the criterion of whether a pipeline MAOP is above or below the 30% of SMYS threshold to prioritize work in two ways.

First, PG&E included pipelines in Class 2 locations operating at above 30% SMYS in Phase I, while it excluded pipelines in Class 3 locations operating below 30% SMYS.[31]

Second, PG&E made the decision whether to test or replace based on the 30% SMYS criterion. Pipeline segments with manufacturing threats operating above 30% SMYS are scheduled for replacement, while those operating below 30% SMYS are scheduled for testing.

TURN agrees with PG&E that industry data indicate that the 30% SMYS threshold determines whether a pipeline fails as a leak versus a rupture.[32] Thus, TURN does not oppose using the 30% SMYS criterion for prioritizing work for Phase 1. However, TURN does not believe that the much greater threat of rupture posed by the 30% SMYS operating pressure warrants a default decision to replace. Prudent hydrostatic pressure testing can identify defects

[29] (40 miles * 0.9 * $4.5 mm/mile) = 162 million.
[30] (157 miles * 0.9 * $0.5 mm/mile) = 70.65 million.
[31] 11 RT 1451:14-21, Hogenson, PG&E.
[32] This fact is confirmed by several witnesses for PG&E and TURN. See, especially, Exh. 21, p. 5-2, A 4, Rosenfeld, PG&E.

irrespective of the operating pressure of the pipeline. This issue is addressed in Section 3.5.2, related to the manufacturing threat decision tree.

3.4.4 PG&E Includes Additional Pipe Segments in Phase 1 due to an Arbitrary Definition of "Complete Record" that Conflicts with Commission Guidance

The fundamental goal of the PSEP work is to test or replace pipelines that "were not pressure tested or lack sufficient details related to performance of any such test."[33] The Commission explicitly defined a complete test record as one that includes "all elements required by the regulations in effect when the test was conducted."[34]

PG&E did not use this definition of a complete record. Instead, PG&E continued to use the definition it proposed back in March of 2011. PG&E's definition includes the three elements required under GO-112 (test pressure, test duration, test fluid)[35] as well as the name of the operator.

PG&E has not justified its use of a different criterion to define "missing records" than the one enunciated in Ordering Paragraph 3. In its January 13, 2012 filing in this docket PG&E simply asserted in a footnote that the name of the operator "is critical to ensure 'traceable, verifiable and complete' records." When pressed to explain this assertion, PG&E stated that the operator name was needed "to ensure the accountability of a witness to test that the test was performed in accordance with the information documented on the pressure test record."[36]

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[33] D.11-06-017, p. 19.
[34] D.11-06-017, Ordering Paragraph 3, p. 31; See, also, D.11-06-017, p. 16.
[35] GO-112 required *records* of only test pressure and medium. Separately, GO-112 required a minimum duration of one hour, though it did *not require* a record of the actual duration. Exh. 54.; See, also, 11 RT 1470:20 to 1471:7, Hogenson, PG&E.
[36] Exh. 70, PG&E Response to TURN 031-01.

TURN completely agrees that on a going-forward basis having the name of the operator to verify the accuracy of test information is necessary information. However, we are here dealing with pipeline installed at a minimum forty-two years ago (if installed in 1970). It is highly unlikely that PG&E could, even if it wanted to, find many operators to corroborate pressure test information. Indeed, PG&E itself admits that looking for those witnesses is "not part of the scope" of its work.[37] But Mr. Singh maintained that without a signature, "how do you know the test was actually conducted"? TURN does not disagree that there might be some added assurance based on a signature on a form.

There is some amount of pipeline scheduled for testing or replacement that contains all relevant testing elements (for example, as required under GO-112) but is missing the name of the operator. However, PG&E cannot specify the mileage of pipeline that is missing this information because its GIS database "does not contain a data field for pressure test Operator/Witness."[38]

Ratepayers should not be on the hook for the fact that PG&E believes that a signature is necessary to ensure the validity of a pressure test record. The Commission should order PG&E to identify the amount of pipeline that is included solely due to the lack of "operator name," and should order PG&E to either eliminate this pipeline from the PSEP, or have shareholders fund the work.

3.5 Manufacturing Threats Decision Tree

3.5.1 DSAW Pipeline Should Be Evaluated for Manufacturing Threats

The PG&E Decision Tree step 1D could be interpreted to suggest that DSAW is not "a manufacturing threat" on PG&E's transmission system. However, DSAW pipe failures

[37] 13 RT 1683, Singh, PG&E.
[38] See, for example, 11 RT 1482:7-10, Hogenson, PG&E.

associated with seam failure have occurred that indicate there are seam risks associated with such pipe, even on gas transmission pipelines.[39] Given the problems associated with DSAW on gas transmission systems and the serious gaps or errors in the GIS, TURN recommends that DSAW should not be included in Step 1D, but that DSAW pipe should be included in Step 1H. The result is that DSAW pipe would be a candidate for the modified Steps M4, M2, or M5 as indicted below; however, any such DSAW pipe be subject to a strength test rather than replacement.

PG&E responded to TURN's recommendation by explaining that it was unnecessary to evaluate DSAW pipe in the manufacturing threat decision tree since any DSAW pipe would ultimately flow though to the corrosion threat decision tree and be hydro tested if lacking records.[40]

TURN appreciates PG&E's explanation, and we accept that PG&E intends to hydro test DSAW pipe. The decision tree indicates that any DSAW pipe operating in a populated area at above 30% SMYS would end up in Step C2 and be scheduled for strength testing in Phase 1.

However, as discussed in Section 3.7 below, PG&E's program includes almost 300 miles for testing resulting from the other outcomes in the corrosion tree, which theoretically assign all work to Phase 2. TURN has not analyzed this issue to understand the basis for the outcome, and we presume this mileage is a significant portion of the work that DRA and CCSF recommend be reprioritized. In any case, TURN is concerned about relying on the outcome of PG&E's corrosion tree as the default, and instead recommends that DSAW pipe be explicitly evaluated in the manufacturing threat decision tree that actually identifies the risk associated with DSAW.

[39] PHMSA Workshop presentation to Joint Technical Advisory Committee, "Managing Challenges with Pipeline Seam Welds and Improving Pipeline Risk Assessments and Recordkeeping," August 2, 2011, slide 11 showing gas line Pipe Seam Failures (2002-2010) by Seam Type including nine DSAW failures for gas transmission pipelines.
[40] Exh. 21, p. 3-4, A. 5 and A.6, Hogenson, PG&E.

3.5.2 PG&E Should Hydrotest Most of the Pipeline with Manufacturing Threats Rather than Defaulting to Replacement

PG&E's Decision Tree for manufacturing defects results in the decision to replace 124 miles of pipeline, including 100 miles directly from decision point M2. Step M2 results in a decision to replace all large diameter HCA pipelines with manufacturing threats that operate at ≥30% SMYS. The exact same pipeline would be tested if it operates at less than 30% SMYS, and thus flows through to Step M4.

TURN believes the majority of pipeline meeting step M2 should be able to be hydrotested. If 95% of this pipeline could be hydrotested, the result would be a reduction of $427.5 million in capital costs and an increase of $47.5 million in expenses.[41]

PG&E should modify Step M2 to provide for the option to hydrotest rather than replace the pipeline. A prudent hydrotest will discover the presence of any manufacturing seam weld defect.[42] Before proceeding to a replacement decision PG&E should be required to provide an additional step to summarize, for a particular pipeline segment, what critical factor or factors led to the decision to replace a particular pipeline segment.

The Commission ordered PG&E to "set forth criteria on which pipeline segments were identified for replacement instead of pressure testing."[43] PG&E's entire direct showing provides no explanation for why replacement is necessary, or why the 30% SMYS criterion should be

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[41] In estimating all cost impacts due to changes in work scope, TURN uses PG&E's average cost of $4.5 million/mile for replacement and $0.5 million/mile for hydrotesting.
[42] Exh. 131, p. 19-21, Kuprewicz, TURN. PG&E agrees with the fundamental premise that hydrotesting is an appropriate assessment method for manufacturing threats. 12 RT 1511:16-21, Hogenson, PG&E.
[43] D.11-06-017, Conclusion of Law 6, p. 29.

used to differentiate between testing and replacement. PG&E's detailed threat assessment does not provide additional justification for the decision to replace rather than test this pipeline.[44]

In its rebuttal testimony PG&E essentially agrees with TURN's analysis. PG&E did not attempt to defend the policy of replacement, but instead agreed that hydrotesting may be an option depending on specific segment characteristics:

> The Decision Tree results must be combined with practical engineering judgment. If, based on records validation and PG&E's engineering judgment, a strength test would provide the same level of safety as replacement, and it makes sense to strength test rather than replace, PG&E will strength test. Such engineering judgment however, can only be applied on a case-by-case basis.[45]

During cross examination, Mr. Hogenson further explained that PG&E would look at "the particular pipeline, its location, its operating stress, its history, … the year it was manufactured, the type of long seam, its location on our system."[46] However, Mr. Hogenson did not explain why these factors could not be considered in advance, since they are the same factors listed in the decision tree. There may be some valid factors warranting replacement. TURN's witness Kuprewicz identified some factors in his own testimony - for example, if the pipe qualities are unknown or there are poor girth welds in unstable soils - that may warrant replacement.[47] Mr. Kuprewicz agreed in oral testimony that vintage pipeline with certain manufacturing characteristics is inferior to new pipe and has a higher risk of failure if not properly managed.[48]

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[44] Exh. 1, p. 3B-13-14, PG&E.
[45] Exh. 21, A45, p. 3-22:3-8, Hogenson, PG&E. The quotation represents PG&E's complete substantive response to this issue.
[46] RT 1508-1509, Hogenson, PG&E.
[47] Exh. 131, Sec. 2.3.2, p. 20, Kuprewicz, TURN.
[48] 15 RT 2216:5-2217:12, Kuprewicz, TURN. There was additional discussion concerning PG&E's recommendation to replace pipeline with "certain construction techniques." However, only 16 miles of pipeline is scheduled for replacement due to the fabrication and construction

But PG&E's Decision Tree fails to explain how these parameters could lead to a decision to test rather than replace. PG&E's own rebuttal provides absolutely *no information* on how PG&E would decide "it makes sense" to strength test rather than replace. Most importantly, PG&E fails to explain why the *default* choice is not testing, a cheaper alternative that is a proper method for assessing manufacturing threats,[49] rather than the more expensive capital cost of replacement. When pressed, Mr. Hogenson fell back on the fact that these pipelines are "old," and thus "very good candidates for replacement given their age."[50]

During oral testimony, CPSD questioned Mr. Kuprewicz extensively on the potential merits of "new pipe" versus "old pipe." TURN does not disagree that with proper quality control modern manufacturing techniques are improved and new pipe is superior to old pipe.[51] However, such a conclusion has little to do with the question of whether old pipe is safe or not. Mr. Kuprewicz reiterated numerous times that pipeline installed in the 1930's, 1940's and 1950's can operate perfectly well if the operator has sufficient records to identify pipeline characteristics and properly evaluate the pipeline for any existing threats.[52]

More importantly, PG&E is not really making a selection based on age, but rather based on the 30% SMYS criterion. As discussed elsewhere, TURN agrees that the 30% SMYS cutoff is valid for differentiating potential leaks versus ruptures. But pipelines operating above 30% SMYS can absolutely be tested to determine integrity and set the MAOP.

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decision tree, and TURN's testimony recommending against automatic replacement applies primarily to the manufacturing decision tree results.

[49] There is general consensus that hydrotesting is appropriate for assessing manufacturing threats. R 1512:8-10, Hogenson, PG&E.

[50] 12 RT 1513:7-24, Hogenson, PG&E.

[51] For example, 15 RT 2158-2159, Kuprewicz, TURN.

[52] Exh. 131, p. 20-21, 82, Kuprewicz, TURN.

Mr. Kuprewicz very roughly estimated that "on the order of 95+%" of the pipeline from Step M2 could be tested rather than replaced.[53] PG&E offered no estimate of how many miles could be tested rather than replaced. The Commission should not leave a choice that has such a huge cost impact solely up to utility discretion based on absolutely no evidence concerning the factors that may influence engineering judgment. Simply put, PG&E has not met its burden of proof to show that replacement is necessary. Rather than allowing PG&E to choose, the Commission should take the following approach.

The preferred course is for the Commission to authorize PG&E to hydrotest the 124 miles of pipeline with manufacturing threats, thus reducing the capital cost forecast by $558 million and increasing expenses by $62 million. If PG&E has specific reasons that warrant replacing any of this pipeline, PG&E should be required to file an advice letter at periodic intervals documenting the specific justification for replacement.

3.5.3 The Commission Should Modify the Order to Allow for Other Threat Assessment for Steps M4 and M5

PG&E intends to hydro test almost 250 miles of pipeline with manufacturing threats operating at less than 30% SMYS.[54] PG&E is correct that the Commission has ordered it to test or replace pipelines without adequate records of historic test pressures.

TURN recommends that the Commission modify its order for purposes of pipelines falling into this category. Simply put, it is not necessary from a safety perspective to test these pipelines, and the Commission should determine and authorize an alternative method for setting

[53] Exh. 131, p. 21, Kuprewicz, TURN.
[54] Exh. 131, Figure 1, p. 10. The mileage results from Steps M4 (operating in HCA) or Step M5 (non-HCA). While Step M5 calls for replacing or testing in Phase 2, apparently about 23 miles are included in Phase 1.

a valid MAOP.[55] There is general agreement that pipelines are not likely to rupture at operating levels below 30% SMYS.[56]

Indeed, the federal test regulations in Subpart J differentiate between pipelines operating above or below 30% of SMYS. A hydrostatic strength test is required in Part 192.505 for any pipe operating at or above 30% SMYS; but a hydrostatic strength test is not required for pipe operating below 30% SMYS. Part 192.507 allows such pipe to be tested for leaks by a strength test using the natural gas in the pipeline. The 30% SMYS criteria is used repeatedly in federal regulations and industry protocols.

TURN does not claim that a rupture can never occur at pressures below 30% SMYS. However, TURN agrees with PG&E's main expert on hydrotesting and ruptures that such occurrences "are rare," and result due to specific risk factors, such as "in very low toughness materials, or where long and deep selective corrosion occurs, or where a selective corrosion condition occurs coincident with seam manufacturing defects."[57]

Hydrotesting these 250 miles of pipeline is not necessary and adds approximately $125 million in expenses.

3.6 Fabrication and Construction Threats Decision Tree

The end result of the Fabrication and Construction Threat decision tree is fairly minimal, with about 16 miles of replacement and 13 miles of testing resulting from outcomes F2 and F3. However, PG&E has not quantified how many miles might be replaced due to the Engineering

[55] The Commission should schedule workshops and comments in this proceeding to determine an appropriate alternative method for setting the MAOP and ensuring proper threat assessment on these pipelines.
[56] Exh. 21, p. 1452-1453, Hogenson, PG&E; Exh. 131, p. 21, Kuprewicz, TURN.
[57] Exh. 21, p. 5-2, A 4, Rosenfeld, PG&E.

Condition Assessment evaluation resulting in outcome F1. TURN recommends the following two modifications to PG&E's work scope.

3.6.1 The ECA Analysis Needs to be Better Defined

The Engineering Condition Assessment ("ECA") proposed in Decision Tree Step 2C is not adequately explained, and thus we cannot evaluate whether PG&E's planned work is sufficient to address fabrication or construction threats. PG&E does not yet have the ECA procedure in place, and is planning to develop the ECA as part of the PSEP work.[58] There is simply too much left to PG&E's discretion. More specifically, ASME B31.8S-2004 which is specifically incorporated in federal pipeline safety integrity management regulations, only permits ECA for "some defects" related to third party damage, manufacturing and construction welding, <u>not</u> in most of the situations defined in step 2B.[59]

The Commission should require some technical review of PG&E's eventual ECA prior to authorizing its use to assess pipeline threats. Such assessment should include review by CSPD staff as well as outside input. The Commission should order PG&E to file a Tier 2 or Tier 3 advice letter with the proposed engineering condition assessment, so that outside parties could provide input.

3.6.2 Pipeline with Specified Construction Threats Should be Assessed with an Abnormal Loading Analysis

TURN recommended in direct testimony that PG&E's decision tree be modified to replace Step 2F ("Has sub-part J strength test been conducted") with a step that asks whether an abnormal loading analysis has been performed. If such an analysis is performed and indicates no

[58] Exh. 21, p. 3-6, A10, Hogenson, PG&E. See, also, Exh. 133, Attachment 2, PG&E Response to TURN_08-03.
[59] Exh. 131, p. 22 and Exh. 133, Attachment 4, Kuprewicz, TURN.

load threat for a particular segment, that segment can be directed to the corrosion threat decision tree.[60]

As explained by Mr. Kuprewicz, questioning whether a strength test has been performed is irrelevant from a safety perspective, since a hydrotest is not the appropriate assessment tool for the girth welds and connections identified in Step 2E. An abnormal loading test analysis that can identify a pipeline segment's potential to physically separate at a pipe connection is critical.

PG&E responded by noting that removing existing Step 2F would result in testing or replacing pipeline that had already been tested.[61] TURN understands PG&E's position and generally agrees that the PSEP should not retest pipelines already tested. Thus, TURN modifies our recommendation to be that a Step 2FA be *added* to the decision tree after the "no" output to Step 2F. Step 2FA would ask whether an abnormal loading test analysis has been performed. If the answer is "yes," the segment would proceed to the Corrosion Tree.

As discussed in Section 3.5.3 above, this change would require the Commission to modify its original order to allow for some pipeline not to be tested, even if records of a prior test are lacking. Once again, a hydrotest would not provide useful threat assessment, though it would serve to establish the MAOP.

3.7 Corrosion and Mechanical Damage Decision Tree

The results of PG&E's corrosion and mechanical damage tree outcomes need to be closely scrutinized by the Commission. In theory, only Step C2 is supposed to result in strength testing in Phase 1. Step C2 includes 195 miles for Phase 1 hydrotesting. However, all seven steps

[60] Exh. 131, p. 22-23, Kuprewicz, TURN. Mr. Kuprewicz proposed an alternate decision tree to replace PG&E's steps 2F, 2G, F2 and F3.
[61] Exh. 21, p. 3-7, A.12.

C1-C7 include significant mileage for hydrotesting, with an *additional* 298 miles scheduled for hydrotesting from Steps C1 and C3-C7.

PG&E's testimony fails to explain how an additional $150 million of expenses results from outcomes that are supposed to result in no work in Phase 1.[62] The Commission should dismiss this work from Phase 1.

PG&E does explain in its testimony that there are 237 miles of pipeline scheduled for hydrotesting that are included for construction "efficiencies."[63]

TURN does not dispute that it may be prudent to include additional mileage for hydrotesting. TURN agrees with DRA that due to the high fixed costs for hydrotesting, it is reasonable "to include not only adjacent segments to Phase 1 hydrotests, but potentially close segments that are not contiguous."[64]

However, the amount of additional mileage for hydrotesting appears excessive. DRA and CCSF provide extensive testimony showing that as part of a 92-foot replacement project on Line 108, PG&E has included an additional two-and-a-half miles for replacement for construction efficiency.[65] TURN has not analyzed the exchange concerning Line 108 replacement, but we strongly recommend that the Commission evaluate closely the arguments made by DRA and CCSF to ensure that PG&E is not inappropriately including too much work in Phase 1 that should be delayed until a later phase.

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[62] Calculated using PG&E's average unit cost of $500,000 per mile for hydrotesting. DRA calculates that $137 million of the hydrotesting expenses "could be addressed after 2014." Exh. 144, p. 46. Presumably, there is close overlap in these numbers.
[63] Exh. 21, p. 3-29 to 3-30, Hogenson, PGE.
[64] Exh. 144, p. 47, Roberts, DRA.
[65] Exh. 137, p. 72, Radigan, CCSF.

TURN's witness Kuprewicz also testified that for corrosion threats ILI is superior to hydrotesting for threat assessment. PG&E agrees.[66] PG&E has chosen to hydrotest in Phase 2 solely to comply with the decision. Mr. Kuprewicz recommended an alternative decision tree that assess specifically for the threat of stress corrosion cracking.[67] For pipelines with SCC threats, remediation, including replacement or hydrotesting, is appropriate.

For other outcomes, TURN recommends ILI if operating in HCAs at more than 30% SMYS (similar to PG&E's Steps C2 and C1). For pipelines operating below 30% SMYS, TURN recommends leak surveys and right-of-way monitoring (for outcomes similar to PG&E's C3 and C5).[68] These activities are sufficient in assessing relevant corrosion and mechanical damage threats on these pipeline segments. Similar to our recommendation concerning steps M4, M5 and F3, TURN recommends that the Commission modify its order to test or replace *all* pipelines without test records. The Commission should consider an alternative to set an appropriate MAOP, and should require prudent operations (leak surveys and monitoring) to continually assess for corrosion and mechanical damage threats.

3.8 PG&E Should Utilize Higher Hydrotest Pressures Whenever Possible

3.8.1 Inadequate Pressures May Result in False Sense of Security and the Need to Retest Lines

TURN is concerned that PG&E is conducting hydrostatic testing, the key safety component addressing over 65% of the 1200 miles of pipeline included in Phase 1 of the PSEP, in a manner that will not identify safety problems and will result in wasted ratepayer money.

66 12 RT 1497:25 – 1498:13, Hogenson, PG&E.
67 Exh. 131, p. 25, Kuprewicz, TURN.
68 Exh. 131, p. 26-29, Kuprewicz, TURN.

PG&E is conducting tests at the proper ratio of test pressure to MAOP.[69] However, while PG&E acknowledges that its standards require testing to 90% of the Specified Minimum Yield Strength ("SMYS"), it does not actually meet this standard in practice. Due to the incredible patchwork of additions, replacements and fixes, each pipeline includes segments of widely differing characteristics, including different pipe yield strengths. The result is that it is difficult to test to a minimum of 90% SMYS without cutting up the pipe into multiple subsections for testing, thus allegedly causing the hydrostatic testing costs to "double or triple."[70]

TURN appreciates PG&E's dilemma. We do not believe that each and every tiny segment must be tested to 90% SMYS. However, we do believe that each mainline segment should be tested at 90% SMYS. The key to this problem is the same as several other problems that involve "engineering judgment." The Commission must ensure that PG&E's engineering judgment decisions are transparent and justified. The Commission should adopt a process that allows substantive input to PG&E's decision-making and provides for oversight and auditing of the results.

3.8.2 There Is No Dispute That Industry Standards, and PG&E's Own Standards, Require Hydrotesting at a Minimum Pressure of 90% SMYS

Despite some confusion regarding hydrotest standards and Subpart J standards, PG&E essentially agrees with TURN that hydrotesting should be done at test pressures of 90% of the pipe's specified minimum yield strength ("90% SMYS"). PG&E's own expert on hydrostatic testing agrees that "PG&E standards require that all new transmission pipeline be tested to at

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[69] Though it is important to remember that the 'MAOP' number is determined first (presumably through MAOP validation) and is the driver for a test pressure number 1.5 times higher for pipeline segments in Class 3 and 4.
[70] Exh. 21, p. 4-11, line 5, Campbell, PG&E.

least 90% SMYS."[71] This standard is contained in PG&E's Piping Design and Test Requirements Gas Standard A-34, identified as Exhibit 103 in the record.

Mr. Campbell claimed in rebuttal testimony that this standard applies to "new pipe," and not to in-service pipeline. This claim is not supported by PG&E's own operating procedure documents. PG&E conducts hydrotests on new pipelines in compliance with federal regulations, and PG&E has conducted a very limited amount of hydrotesting of in-service pipeline as part of integrity management. [72] PG&E's Gas Standard A-34 does not distinguish between new or in-service pipeline, but applies to any hydrostatic test. The very first section of the document states that "[t]his gas standard establishes a uniform procedure for designing and testing gas piping systems that will meet the requirements of 49 CFR 192."[73] Mr. Campbell acknowledges this fact, but then claimed in oral testimony that PG&E's standards have "a gap."[74]

PG&E has been hydrotesting pipelines for integrity management since 2004. But even before integrity management, PG&E had been hydrotesting in-service pipelines, for example due to class location changes.[75] PG&E's Gas Standard A-34 was revised in December 2003, when PG&E was preparing to do its integrity management assessment. Mr. Campbell's suggestion implies that PG&E revised its standards in anticipation of integrity management assessment work without considering how to do a hydrotest on in-service pipeline. It further implies that

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[71] Exh. 21, p. 4-10, lines 9-11, Campbell, PG&E.
[72] PG&E has completed approximately hydrostatic tests on approximately 14 miles of pipeline for integrity management. Exh. 1, p. 2-17, Table 2-5, Hogenson, PG&E.
[73] Exh. 103, p. 1.
[74] 13 RT 1835, Campbell, PG&E.
[75] Indeed, while Mr. Campbell testified that he was involved with pressure testing prior to integrity management, he also explained that the types of tests he was involved with were typically associated with "a class location change." Presumably such tests involved in-service pipeline, rather than new (post construction) pipeline. RT 1857:2-10 and 1835:13-25, Campbell, PG&E.

PG&E continued with its 2003 version of Gas Standard A-34 with this "gap" throughout the entire period of conducting the first round of assessments under integrity management. It is difficult to understand why PG&E would have continued hydrotesting without ever addressing this "gap."

Industry standards for hydrotesting do distinguish between "post construction" and "in-service" pipeline. But the applicable requirements are the reverse of what is suggested by Mr. Campbell. Section 841.3 of ASME B31.8-2007 provides guidance for testing pipelines "after construction," and requires minimum ratios of pressure test to MAOP.[76] However, for purposes of assessing the integrity of "in-service pipelines," Section 851.12 requires a minimum strength test pressure "which will cause a hoop stress of at least 90% of the SMYS in the segment with the lowest design or rated pressure in the section tested."[77]

There are two exceptions to the minimum pressure requirement, including for "those pipelines for which the hoop stress percent of the SMYS cannot be accurately determined or those pipelines that operate at hoop stress levels lower than maximum design pressure, the minimum strength test pressure shall be 1.10 times the MAOP."[78] Mr. Campbell testified that based on conversations with Mr. Rosenfeld, PG&E interprets the phrase "maximum design pressure" as meaning 72% of SMYS, *not* the maximum pressure of the segment based on its design characteristics, though Mr. Campbell agreed that "it is unclear in this document what that means."[79]

[76] Exh. 102, Sec. 841.32 and Table 841.322(f), p. 39-40 (as numbered in original). Reprinted with permission of ASME.
[77] Exh. 102, Sec. 851.12.1(a), p. 72 (as numbered in original).
[78] Exh. 102, Sec. 851.12.1(c), p. 73.
[79] 13 RT 1864:13 – 1866:10, Campbell, PG&E.

TURN is extremely concerned that PG&E's interpretation of this section does not provide the most safety-conscious results. TURN notes that Section 805.212 of B31.8 defines "design pressure" as "the maximum pressure permitted by this Code, as determined by the design procedures applicable to the materials and locations involved."[80] It would seem that this definition results in a unique maximum design pressure for each pipe based on its characteristics, not one maximum design pressure of 72% of SMYS.

3.8.3 The Real Reason for Low Pressure Testing is the Mishmash of PG&E's Transmission Lines

Mr. Campbell's distinction between in-service and new pipe was an *ad hoc* excuse. But Mr. Campbell cogently explains why PG&E believes that its own standards are not "practical" for its pipeline system:

> A pipeline that has been installed prior to 1970, as are most of the pipelines proposed for hydrostatic testing in PG&E's Implementation Plan, have multiple types of pipe characteristics, valves, fittings and appurtenances. The varying characteristics are because sections of the original pipe may have had multiple replacements over the years due to class location changes, relocations for developments, capacity increases, etc. Some of our hydrotests in 2011 had as many as 10 different types of pipe with various wall thicknesses and SMYS. … It would be cost prohibitive for any pipeline operator to cut each differing segment and hydrotest it separately to achieve 90 percent for every segment.[81]

Mr. Campbell further cautioned that without cutting each pipe into small segments, some of the segments might get pressurized above 100% SMYS. Mr. Campbell claims that to perform testing adequately to ensure 90% SMYS would "double or triple" the costs of the hydrotesting program.

[80] While we would request official notice of this document, the disturbing reality is that the ASME documents which are incorporated in Part 192 of the Code of Federal Regulations are proprietary documents which cannot be freely accessed by the public.
[81] Exh. 21, p. 4-10 to 4-11, Campbell, PG&E. See, also, 13 RT 1830-1831, Campbell, PG&E.

The results of PG&E's 2011 hydrotesting program, and PG&E's reluctance to embrace its existing standards, raises a serious concern. In 2011 PG&E hydrotested approximately 158 miles of pipeline. Only 57.73 miles were hydrotested to a minimum of 90% SMYS.[82] Of even greater concern is the fact that 19 miles, or about 12%, were tested to below 70% SMYS.[83]

And these numbers are highly conservative (meaning favorable to PG&E) since they include all the mileage in a hydrotest based on the highest test pressure achieved for any single segment. Because of the varying SMYS in multiple segments included within a hydrotest, when one considers the pressure achieved in any segment included in the hydrotest, the result is that almost one-third (53.58 miles) of the hydrotested lines were tested at pressures below 70% of SMYS.[84]

TURN appreciates PG&E's dilemma. Apparently its historical replacements and repairs have resulted in a patchwork of pipe with very different SMYS all joined together. TURN does not intend that PG&E should hydrotest each and every minute segment, valve or fitting. Our concern is really with mainline pipe that might have seam threats. Our fundamental concern is whether PG&E is 'segmenting' its hydrotests as much as is possible to achieve optimal safety results.

PG&E has likely overestimated the potential cost impacts of segmenting its pipelines to achieve higher test pressures due to PG&E's opposition to raising test pressures above 100% SMYS in any portion of the pipeline, thus requiring more potential segmentation than necessary. The record does not support such an inflexible restriction against hydrotesting above 100%

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[82] Exh. 101, Table 1. This number reflects the highest pressure in any segment of the test. If one considers the pressure achieved in any segment included in a hydro test, the result is even lower, with only 38.11 miles tested to 90% SMYS or greater.
[83] Exh. 101, Table 1.
[84] Exh. 101, Table 2.

SMYS. PG&E's own expert explained that spike testing "in the range of 105% to 110% of SMYS" is at times appropriate.[85] ASME standards allow for certain test pressures "of at least 100% SMYS," when evaluating for stress corrosion cracking.[86]

3.8.4 Hydrotesting Is an Assessment Tool, Not Just a Method to Corroborate an MAOP

Hydrostatic testing is used for both establishing a pipeline's maximum allowable operating pressure under subsection 192.619 of the federal code, as well as for assessing certain identified threats, especially manufacturing seam threats, pursuant to integrity management. As discussed above, the ASME B31.8 standards require minimum *ratios* of test pressure to MAOP for post-construction strength tests, but require a minimum test pressure of at least 90% of SMYS for strength tests of in-service pipelines.

PG&E argues that as long as the hydrotest complies with the 619 test pressure to MAOP ratio requirements, the absolute level of pressure (relative to the SMYS of the pipeline) is not important. But we should not be spending the effort and money to hydrotest the pipeline in a manner that is insufficient to fully evaluate potential threats, especially seam threats such as that which caused the San Bruno rupture. If PG&E's hydrotesting is insufficient to assess for pipeline seam threats, TURN is concerned that the testing may prove inadequate to prevent potential future pipeline ruptures.

PG&E attempts to assuage this concern with expert testimony explaining that as long as the hydrotest pressure is at least 1.25 times the MAOP, the growth times to failure of any seam defects will be "on the order of 150 years."[87]

[85] Exh. 131, p. 33, Kuprewicz, TURN (quoting letter from Rosenfeld to Yura).
[86] Exh. 102, p. 72, Sec. 851.12.1(b). See, also, 13 RT 1842, Campbell, PG&E.
[87] Exh. 21, p. 5-2, A 3, Rosenfeld, PG&E.

TURN is extremely concerned about PG&E's reliance on just the pressure test ratios. The MAOP of a pipeline is the driver for determining the hydrotest pressure. The MAOP in turn is based at first on PG&E's use of records and assumptions in its MAOP validation program.

It is only the SMYS number that is unique, based on the physical characteristics of the pipeline. While the MAOP may also be linked to pipeline characteristics, it is not a set number. The MAOP depends on the weakest link, and PG&E's pipeline MAOPs do not appear to be set as high as possible.

A high pressure hydro test is also necessary to evaluate the impacts of cyclic fatigue. PG&E has determined that cyclic fatigue is simply not relevant to its pipelines, based on the results of the 2007 Kiefner Report.[88]

The issues of threat stability, cyclic fatigue, crack growth and failure as they relate to a proper hydrotest pressure are highly complex and technical. These are difficult issues to resolve in litigation briefs; but unfortunately they are also critical to future safety. Therefore, TURN recommends that the Commission order PG&E to hydrotest pipelines to at least 90% SMYS if possible, and to report to CPSD the reasons why particular segments cannot be tested to this level. The Commission should also direct CPSD to organize a technical workshop, not sponsored or headed by PG&E, to obtain expert advice and opinion concerning cyclic fatigue and seam threat assessment with hydrotesting.

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[88] PG&E's RMI-06.

4 Evaluation of Valve Automation Program Component

4.1 Summary of Recommended Modifications

PG&E uses two decision trees to determine valve automation, depending on whether a pipeline segment crosses an earthquake fault or not. TURN does not recommend any changes to PG&E's program addressing segments crossing earthquake faults.

PG&E intends to automate all Class 3 segments that meet either one of two conditions: 1) PIR>200 feet, or 2) more than 50% of the Class 3 segment is in an HCA and the PIR>150 feet.[89] However, PG&E prioritizes for Phase 1 automation valves in Class 3 and 4 locations with a PIR greater than 300 feet and containing "sustained segments" of at least five miles and at least 50% HCAs between existing valves.[90] This results in Phase 1 including approximately 230 valves for automation, covering about 30% of PG&E's HCA mileage in Class 3 locations.[91] PG&E forecasts $132.5 million in capital costs and $11.1 million in expenses for Phase 1 of the Valve Automation Program.

PG&E's decision trees do not address valve automation for HCAs in Class 1 or 2 locations. Although PG&E does not target any valves on segments in Classes 1 and 2, it appears that substantial mileage in Class 1 and 2 will be automated, probably due to the scattering of Class 3 segments near Class 1 and 2 locations, and the locations of existing valves. PG&E did not, however, address Class 1 and 2 segments classified as HCAs due to the presence of identified sites.[92]

[89] PG&E Testimony, Table 4-3, p. 4-38.
[90] PG&E Testimony, p. 4-39.
[91] PG&E Testimony, Table 4-3, p. 4-38 and Table 4-4, p. 4-39.
[92] Exh. 131, p. 35, Kuprewicz, TURN.

PG&E adopts the federal regulatory maximum spacing for Class 3 locations of eight miles for determining valve spacing in either Class 3 and 4 locations. It is unclear what spacing, if any, PG&E adopts for segments that will be automated in Class 1 and 2 locations.

TURN recommends the following modifications to PG&E's selection and prioritization process:

- In general, TURN does not support using the PIR as a primary selection and prioritization criterion for valve automation. TURN recommends that Phase 1 focus on automating valves on pipelines with diameters greater than 24 inches, due to the much greater actual impact area from the higher heat flux and sustained burning from such larger diameter pipelines. In practice, PG&E claims that its Phase 1 program addresses mostly such large diameter pipelines, but the record is somewhat confusing on this issue.
- PG&E should also prioritize for Phase 1 valves in Class 1 and 2 HCAs (identified sites) using the 8 mile maximum spacing criterion. Identified sites are most likely to result in high casualties in the event of a rupture. The number of valves identified by PG&E for such Class 1 and 2 HCA valve installation appears to be highly overstated. The Commission should order a review by an independent party of PG&E's specific class 1 and 2 HCAs and valve locations.
- TURN originally recommended that PG&E install only Automatic Shut-Off Valves (ASVs) on large pipeline. PG&E's concerns about the false closure of ASVs are overblown and based on using ASVs in the most simple configuration. PG&E admits that ASVs could be installed in a manner that eliminates the problem of false closure. However, if PG&E needs to obtain greater operational experience with ASVs, the Commission should order that PG&E either install the ASVs in phases, or at a minimum

that PG&E install at least 20% of the planned 230 valves on large diameter pipelines as ASVs, in order to test PG&E's design approach and operation.

- PG&E's contention that valves can be installed in either ASV or RCV mode and retrofitted later is troubling, since PG&E's own testimony shows that to operate ASVs using a complex design approach requires additional measuring and communications equipment. The Commission should order PG&E to install ASVs with appropriate equipment and software to operate using complex algorithms and sensor information.
- PG&E has not provided any record evidence to determine whether their planned Control Room Management initiative will address the issues of control room emergency procedures, control room authority, and control room operating training and performance, which were identified in the NTSB Report.

4.2 PG&E Should Install More Automatic Shut-Off Valves (ASVs) Rather than Relying Exclusively on Remote Control Valves (RCVs)

4.2.1 The Benefit of Valve Automation is Reducing Human Response Times

A block valve can isolate and close off a portion of a gas transmission line. PG&E has approximately 2600 isolation valves on its transmission lines, of which at least 700 are on HCA pipeline. Approximately 300 of these valves are automated.[93]

The time to vent a pipeline after a rupture includes three main components: the time it takes to identify the rupture and initiate valve closure (the so-called "response time"), the time it takes physically to close the valves on either side of the rupture (upstream and downstream), and the time it takes for gas to vent out of the rupture hole once isolation valves are closed (the so-called "blowdown time").

[93] Exh. 136.

For a standard manual isolation valve, the "response time" includes two components. The time it takes the control room operator to identify a rupture and issue an order to close the valve, and the time it takes a field employee to get to the valve location to initiate physical valve closure. Automating a valve in either remote control (RCV) or automatic shut-off (ASV) mode by installing hardware that electronically initiates valve closure (an actuator) eliminates this second step in the response time.

The primary difference between an ASV and an RCV automated valve is that the RCV valve closure must be initiated by a remote signal from the control room operator. The ASV valve closes automatically based on pre-set conditions. The response time of the ASV valve can be programmed to be one minute or longer. The ASV valve thus eliminates the human operator response time; though it can be programmed to allow an override within a pre-set amount of time, and can even be designed to alarm to the Control Room Operator well before initiating closure. [94]

4.2.2 Automated Shutoff Valves (ASVs) Eliminate the Likelihood That Operator Response Times and Pipeline Blowdown Times Will be Longer than Estimated, and Thus ASVs Provide Greater Chance of Achieving the Thirty-Minute Target for Stopping Gas Flow

It appears that PG&E's design criterion for the valve automation program is to ensure that sufficient pipeline venting (or "blowdown") occurs within 30 minutes of a pipeline rupture.[95] TURN supports this 30-minute goal for venting the pipeline.

There appears to be agreement among the experts that it takes a large mainline isolation valve about five to ten minutes to close, irrespective of whether operated manually or remotely.

[94] 11 RT 1326, Menegus, PG&E.
[95] Exh. 1, p. 4-30:12-17, Menegus, PG&E. See, also, 11 RT 1301:22-26, Menegus, PG&E.

Thus, to achieve blowdown within thirty minutes leaves about twenty minutes total for the operator response time and pipeline "isolation blowdown time."

The critical difference between TURN and PG&E is in our calculation of the operator response time and the isolation blowdown time. These technical issues are discussed below. The isolation blowdown time is based on physical properties of the pipeline and is influenced by valve spacing. Operator response time depends on various valve, field monitoring equipment and SCADA design factors, as well as all the elements that go into operator training and control room operations.

Because TURN believes blowdown times for large transmission lines with valves spaced no greater than 8 miles are likely on the order of fifteen (15) to twenty (20) minutes, we do not believe the installation of RCVs can accomplish blowdown within thirty minutes, since the operator response time would have to be on the order of one to five minutes. Even if blowdown times are more like the five to ten minutes claimed by PG&E, operator response times would still need to be less than 15 minutes to achieve the 30-minute target. PG&E's entire valve program is premised on achieving operator response times of less than 15-minutes, and assuming a blowdown time of less than five minutes.

Achieving a response time of even 15 minutes is quite ambitious. In fact, TURN does not believe PG&E's twenty minute forecast for the sum of operator response time plus blowdown time is reasonable. It is for this reason that we recommend transitioning to the use of prudently designed "smart valve" ASVs. Such ASV approaches, embracing the concepts of process safety management, eliminate the errors and delays due to operator response time, and thus provide a greater potential to achieve blowdown of the pipeline within thirty minutes.

4.2.3 PG&E Underestimates the Likely Operator Response Time, Which Could Easily Surpass 15 Minutes

PG&E's current procedures for responding to SCADA alarms envision twenty minutes for the operator to process, analyze and respond to any alarm.[96] PG&E has a "goal" of having control room operators identify a rupture based on SCADA information and initiate valve closure within fifteen minutes.[97] The potential success of meeting a 30-minute blowdown time depends on this goal. PG&E has not demonstrated that it will achieve such a rapid response time.

In a control room operating a system as complex as PG&E's gas transmission system, time during a rupture event can pass very quickly as the operator may not be able to quickly ascertain that a rupture has indeed occurred on a particular pipeline segment. The use of ASVs eliminates the delay due to operator response times.

The San Bruno pipeline rupture is PG&E's only real world experience with processing information related to a rupture so as to initiate valve closure. As documented extensively in the NTSB Report, PG&E's control room staff, which included three highly experienced operators, were unable to conclusively identify and respond to the rupture.[98] The first low pressure alarm sounded at 6:15 p.m., about four minutes after the rupture. While one operator testified that he knew there was a break on Line 132 by 6:30 p.m., as late as 6:50 p.m. there was conflicting information being provided.[99] It does not appear that control room operators ever made decisions to shut down relevant valves. The NTSB Report is highly critical of PG&E's command structure related to alarm response.

[96] NTSB Report, p. 52.
[97] Exh. 1, p. 4-24:14-30, Menegus, PG&E; and 11 RT 1302:17 – 1303:20, Menegus, PG&E.
[98] Information concerning the SCADA control room, the control room operators and events on September 9, 2010 are scattered throughout the NTSB Report. This section of the brief relies primarily on facts contained at pages 12-17, 22-23, 51-52, 98-100 and 101-102 of the NTSB Accident Report.
[99] NTSB, p. 16 and 101-102.

PG&E's control room presently receives about 600 alarms per day, including 22 classified as critical.[100] PG&E's current alarm management process prioritizes the alarms into four levels – critical, warning, normal and information.

PG&E is implementing new Control Room Management regulations for managing alarms. The new process will prioritize alarms into four different levels – Emergency, High, Medium and Low. PG&E believes that this new alarm management process will reduce the number of crucial alarms, clarify what's going on for operators and provide operators with better protocols for decision making. [101] This new system, which PG&E is currently working to implement with the assistance of industry experts, is supposed to provide control room operators with the ability to respond within fifteen minutes.

It is impossible to evaluate the potential for the new Control Room Management system to fundamentally solve the many problems identified in the NTSB Report. The system is just being developed, and we know little about it aside from the fact that the four alarm designations are being given new names. PG&E has not provided sufficient evidence to conclude that the new system will be sufficient to meet the fifteen minute operator response time target. Given Mr. Kuprewicz's extensive experience in control room operation/investigations as well as his involvement in attempting to improve federal control room pipeline safety regulation,[102] without more specific details, TURN places little confidence in PG&E's efforts to effectively improve control room gas transmission management and operation, especially during pipeline rupture events.

[100] Exh. 55, p. 5. See, also, 11 RT 1327, Menegus, PG&E.
[101] 11 RT 1333:13 – 1334:3, Menegus, PG&E.
[102] Exh. 133, Attach. 1,

TURN suggests that control room operations and valve automation are related issues which warrant continued monitoring by this Commission. TURN thus recommends that the Commission order PG&E to test its new control room management system under simulated conditions, and to submit an advice letter within one year providing information concerning the new control room management program design and performance.

Additionally, as detailed below, TURN recommends that PG&E deploy at least 20% ASVs right now in Phase 1. The Commission should consider additional modifications to the valve automation program depending on the advice letter data and information.

4.2.4 PG&E Significantly Underestimates Potential Blowdown Times After Valve Closure

After the isolation valves are closed gas will continue to supply the blaze due to the volume and pressure of gas remaining in the pipeline between the isolation valves and the rupture. While it may take hours to fully vent all the gas, the critical parameter is the time to vent a sufficient amount of gas so as to reduce the gas pressure in the pipe to near atmospheric pressure so as to eliminate the extremely high heat flux. The time necessary to vent out the ruptured pipeline segment once an isolation valve is closed is the so-called "blowdown time." The blowdown time is mainly established by a) the valve distance from the rupture, b) the diameter of the pipeline, and c) the initial pressure at the time of rupture.[103]

PG&E claimed that the blowdown time has only "minimal impact on facilitating emergency response." PG&E claimed that the blowdown time for an eight mile valve spacing is less than five minutes.[104]

[103] See, Exh. 131, p. 37, Kuprewicz, TURN. See, also, Exh. 21, p. 6-7, Menegus, PG&E.
[104] Exh. 1, p. 4-22:25-26 and p. 4-23, Figure 4-7, Menegus, PG&E.

PG&E explains that its calculation of a five-minute blowdown time uses a simplified equation that is a common industry tool applicable "to shorter, larger diameter segments."[105] PG&E claims that this approach is reasonable for valve spacing of eight miles, and that additional precision is unwarranted.

PG&E explained that it used the simplified analysis purely to "assess whether the eight-mile maximum was okay or whether we should use something smaller."[106] While TURN does not disagree with PG&E's selection of an 8-mile valve spacing criterion, TURN strongly disagrees with the numerical results of PG&E's blowdown time analysis. The simplified direct solution does not account for pipe friction. Friction reduces the flow rate of the gas and thus increases the time for venting, resulting in much longer blowdown times. PG&E admits that friction "will have an effect on actual blowdown time for an 8-mile pipeline segment."[107]

PG&E agrees that a more accurate calculation of blowdown time is achieved by using a iterative transient analysis. TURN's witness Kuprewicz presented an example of exactly this type of solution based on published industry literature data.[108] The published data show blowdown times more in the range of 15 minutes (for a 36-inch pipe) to 28 minutes (for a 12-inch pipe). Furthermore, a real life example from a rupture on ScCalGas's 18-inch diameter line in 2011 showed a blowdown time of 14 minutes.[109]

The difference between TURN's and PG&E's calculations is at least ten minutes. While this difference may not seem large, it can significantly impact the ability to meet the 30-minute goal for eliminating the high heat flux fire. In combination with our concerns about potential

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[105] Exh. 21, p. 6-7, A9 Menegus, PG&E.
[106] 11 RT 1343:1-19, Menegus, PG&E.
[107] Exh. 55, p. 3, PG&E Response to TURN DR 024-11(b).
[108] Exh. 131, p. 42-44 and Figure 7, Kuprewicz, TURN.
[109] Exh. 131, p. 41-42, Kuprewicz, TURN.

operator impact times, the longer blowdown time analysis supports TURN's recommendation to use automatic shut-off valves.

4.2.5 PG&E's Concerns About False Closure of ASVs Are Overblown and Can be Addressed Through Proper Valve Design

PG&E's primary opposition to installing ASVs rather than RCVs is the problem of "false closures." Simply put, PG&E explains that to an automated valve set to trigger based on pressure readings at one location, a rapid decline in pressure due to the onset of customer gas use, especially on a cold winter day with a large rapid increase in gas use in the morning, would appear exactly the same as a pressure loss due to rupture.[110] The ASV would trigger a valve closure, resulting in the shutoff of gas service to customers precisely when they need it most.

TURN appreciates the gravity of PG&E's concern. A false closure would result in significant inconvenience, and even threat to health and safety, for customers. It would result in significant additional work and a public relations fiasco for PG&E. However, we believe PG&E's false closure concern is totally overblown, since it ignores the ability to engineer a solution with different system design.

PG&E's false closure scenario assumes that the ASV operates based on a one-minute input of data from the one pressure monitoring point at the location of the ASV.[111] PG&E's witness Menegus explained that a control room operator would, especially knowing it is a high demand day, instead rely on pressure signals from additional upstream and downstream pressure and flow points. The operator could analyze pressure declines over a longer period "than that one

[110] Exh. 21, p. 6-19, Menegus, PG&E; See, also, 11 RT 1303-1304, Menegus, PG&E.
[111] See, generally, 11 RT 1306-1308, Menegus, PG&E, for a discussion of this issue.

minute period that's in the ASV controls,"[112] potentially analyzing the signals for five to ten minutes prior to making a decision.

PG&E's comparison between the control room operator and an ASV valve is based on the false premise that an ASV valve must operate based on data from a single pressure monitoring station over the period of one minute. The whole thrust of Mr. Kuprewicz's testimony for TURN was that ASV valves can be configured with much more complex logic controls. Indeed, ASV valves could be configured to trigger only based on the combined input of more than one pressure monitoring point information. Such ASV valve design techniques will incorporate "smart valve" technology to eliminate false closures.[113]

Mr. Menegus admitted in his rebuttal testimony that such more complex configuration is technically possible and would eliminate the false closure problem. Mr. Menegus testified that: "Significant additional pressure monitoring beyond what is being recommended is likely to be required to allow ASVs to replace RCVs and accurately identify a pipeline rupture on pipelines in heavily populated areas with frequent gas delivery taps."[114] Mr. Menegus further explained in oral testimony that an ASV could operate by using essentially the same type of information from multiple pressure monitoring points as would be used by the control room operator.[115]

Mr. Menegus cautioned that using such a complex control scheme, however, would entail relying on the SCADA system for communicating with the ASV, rather than relying on a stand-alone ASV logic control.[116] TURN admits that an ASV with complex controls would rely on SCADA inputs, but we fail to see this as a serious disadvantage. The SCADA system is designed

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[112] 11 RT 1306:24-28, Menegus, PG&E.
[113] NTSB Report, p 104.
[114] Exh. 21, p. 6-4:30-34, Menegus, PG&E.
[115] 11 RT 1311:7-12 and 1314:8-18, Menegus, PG&E.
[116] 11 RT 1310:23-28, Menegus, PG&E.

to be highly robust. Indeed, any RCV valve inherently relies on the SCADA system, since the control room operator must initiate closure based on data from the SCADA system. The operator is entirely dependent on SCADA. If there is a rupture while the SCADA system is down, we are going to be in huge trouble no matter what. TURN also believes that PG&E is limiting their approach to only utilize SCADA. There are other options, such as smart Programmable Logic Controllers, or smart PLCs, that supplement SCADA and help to unload the control room operator tasks.

Moreover, there are likely some practical ways to address PG&E's concern about large pressure drops on high demand days. Extremely high demand changes occur on the few extremely cold winter days, which are forecast ahead of time. PG&E agrees that an ASV can be programmed to allow an operator to review alarm information and even override the ASV.[117] Presumably, operators could be particularly vigilant for overrides on extremely high demand days.

Mr. Menegus asserted that an RCV can be changed to operate as an ASV with only "a minor software configuration change."[118] Mr. Menegus further explained that changing the SCADA system would not require a hardware change.[119] TURN is not fully convinced that installing an ASV so as to use multiple SCADA inputs and operate with complex logic controls is as easy to change as claimed by Mr. Menegus. Mr. Menegus argued that configuring ASVs to respond to complex inputs will require "significant additional pressure monitoring."and SCADA changes should never be made lightly given the importance of these systems to pipeline operations.

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[117] 11 RT 1326, Menegus, PG&E.
[118] Exh. 21, p. 6-5:20-21, Menegus, PG&E.
[119] 11 RT 1323:19 – 1324:18, Menegus, PGE.

PG&E cites to its industry "survey" for the proposition that false closures are a typical problem for operators.[120] But Mr. Menegus admitted that neither PG&E nor most operators have installed ASVs using the multiple data inputs and complex algorithms necessary to identify a rupture without false closures, because "it significantly increases the complexity of the controls."[121] Mr. Menegus was aware of only one operator in the survey which used the SCADA system to trip ASVs.[122] And Mr. Menegus was not aware of any operators using more modern ASVs with new control technologies.[123]

This is precisely why TURN recommends that PG&E install at least some portion of their automated valves as ASVs, but with an up-front design that allows for the complex controls. Yes, there will be added complexity and such complexity is easily handled by prudent process management design. For this reason it is high time to start learning how to deal with it.[124]

4.2.6 PG&E's Position Reflects a General Industry Recalcitrance Towards Automated Valves

Mr. Menegus agrees that ASVs have been around for at least twenty years. PG&E has installed upwards of a hundred RCVs on its system, but has only a dozen or so ASVs.[125] PG&E's situation reflects a long-standing industry recalcitrance to implement automated valve technology, especially in ASV mode.

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[120] Exh. 21, p. 6-3 to 6-4, A3, Menegus, PG&E.
[121] Exh. 21, p. 1316:8-13, Menegus, PG&E.
[122] 11 RT 1321:22-1322:7, Menegus, PG&E.
[123] 11 RT 1326:1-7, Menegus, PG&E.
[124] At the very end of his oral testimony, Mr. Menegus stated that PG&E will be "looking at complex alarming." 11 RT 1364. However, PG&E provides absolutely no further details, and there are multiple times in their testimonies where PG&E emphasizes that they will be installing exactly the same equipment for RCV as needed for ACV, which gives us little comfort that PG&E will really be testing complex alarming and controls using multiple pressure or signal inputs.
[125] 11 RT 1314:19-28, Menegus, PG&E.

In fact, federal regulators have been prodding the industry to move to automated valves for much more than twenty years, as explained in the NTSB Accident Report:

> The NTSB has long been concerned about the lack of standards for rapid shutdown and the lack of requirements for ASVs or RCVs in HCAs. As far back as 1971, the NTSB recommended, in Safety Recommendation P-71-1, the development of standards for rapid shutdown of failed natural gas pipelines. In 1995, the NTSB recommended, in Safety Recommendation P-95-1, that RSPA expedite requirements for installing automatic- or remote-operated mainline valves on high-pressure pipelines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline segments. The NTSB classified Safety Recommendation P-95-1 "Closed—Acceptable Action," believing that the RSPA 2004 integrity management rulemaking (requiring that each gas transmission operator determine whether installing ASVs or RCVs would be an efficient means of adding protection to an HCA) would lead to a more widespread use of ASVs and RCVs. However, it did not."[126]

PG&E was required to consider the use of automated valves for risk protection in HCAs as part of integrity management.[127] A Commission audit in 2005 found that PG&E did not properly consider the factors enumerated in federal regulations. PG&E responded that automated valves would have little effect on increasing safety or protecting property since most damage occurs in the first 30 seconds after rupture.[128] The NTSB, however, concluded that failure to shut off gas flow for 95 minutes "contributed to the severity and extent of property damage and increased risk" caused by the San Bruno explosion.[129]

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[126] NTSB Report, Accident Report NTSB/PAR-11/01, August 30, 2011, p. 103.
[127] 49 CFR 192.935(c).
[128] Exh. 137, p. 27-28, A. 13, Scott, CCSF. See, also, NTSB Report, Sec. 1.9.2, p. 56-57.
[129] NTSB Report, p. 102.

4.2.7 The Commission Should Order PG&E to Install at Least 20% of their Automated Valves in ASV Mode with Complex Algorithms, and Should Order a Technical Workshop if Necessary to Guide System Design

In his testimony on behalf of TURN, Mr. Kuprewicz recommended that PG&E install ASVs on all of their Class 3 and 4 pipelines greater than 24 inches in diameter. Upon considering PG&E's rebuttal arguments, TURN appreciates that due to industry recalcitrance there may be a dearth of technical experience with the type of complex control algorithms necessary to properly design and operate ASV to ensure rupture identification without false closures.

If there is uncertainty concerning the exact nature of what is required to implement this recommendation, the Commission should order a technical workshop, including representatives from federal agencies and other gas operators, to discuss this issue. Analyzing proper valve and SCADA design is precisely the type of issue that would benefit from a technical workshop.

However, the solution is not to condone continued delay and intransigence.

The solution is to order PG&E to take the first steps to obtain the necessary operating experience. TURN's primary recommendation is that the Commission order PG&E initiate ASV installation. Such installation could proceed in a phased manner, so that PG&E gains experience with system design and operations.

Alternatively, the Commission should order PG&E to install 20% of its planned valves as ASVs. In either case, PG&E should install the ASVs with proper monitoring and logic controls, to respond to multiple SCADA input from other monitoring locations. TURN is concerned, however, that PG&E not have too many different system designs on automated valves so as to preclude clear and consistent control room response.

4.3 TURN Recommends a Different Prioritization of Phase 1 Valve Installation

4.3.1 TURN Recommends Prioritizing Large Diameter Pipelines and Pipelines Susceptible to Earth Movement, Rather than Simply Using the Potential Impact Radius

TURN witness Kuprewicz strongly cautioned against using the Potential Impact Radius ("PIR") as the method of prioritizing valve automation. The PIR does not define the actual impact zone, especially for larger diameter pipelines. The San Bruno pipeline rupture was the failure of a 30-inch diameter gas transmission pipeline in a Class 3 Location at a pressure of approximately 386 psig, a pressure failure below the MAOP of 400 psig. San Bruno's calculated PIR value is 414 feet, but building destruction actually occurred up to 750 feet away, because of prolonged exposure to very high heat fluxes.[130]

PG&E responded by defending the PIR calculations, and presenting data showing that the PIR has not underestimated property destruction as defined in the PIR model, though this testimony never explained the discrepancy in the calculated potential impact radius and that observed in the San Bruno rupture.[131]

However, PG&E claims that in practice its prioritization primarily addresses pipelines greater than 24 inches in Phase 1, as recommended by TURN. TURN's calculations showed that 61 out of 194 valves proposed for automation in Phase 1 were located on pipelines less than 24-inch in diameter. Mr. Menegus did not directly dispute this; however, he testified that there were only four "segments" totaling about 24.6 miles that had "not pipe of 24-inch or greater diameter" that were being automated in Phase 1, while there were 53 segments with pipeline greater than

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[130] Exh. 131, pp. 48-49, Kuprewicz, TURN (referring to the NTSB Accident Report, "Figure 11 - Picture showing area of damage from blast and fire," page 19).

[131] Exh. 21, p. 7-3 to 7-6, Stephens, PG&E. In discussing the burn zone in San Bruno, Mr. Stephens switched to calculating the square-foot ground area of the burn zone, rather than a radial distance.

24-inch diameter.[132] Regrettably, the factual record does not explain how to reconcile these conflicting claims.

Mr. Menegus also defends using the PIR, which is a formula that takes into account pipeline diameter and pressure, by comparing two pipelines to show that sometimes a lower diameter pipeline may have greater potential impacts.[133] TURN does not disagree with his example; however, both pipelines in that example operate at extremely unusual pressures and do not reflect normal pipeline operations.[134] TURN agrees that both these pipelines should be prioritized for automation, as PG&E is doing. Indeed, we would even recommend a closer valve spacing for the 2,160 psig pipeline.

TURN completely agrees that the operator must use engineering judgment in unusual circumstances, whether dealing with pipeline testing, replacement or valve automation. The fundamental point of Mr. Kuprewicz's testimony was that from a safety perspective it is more important to prioritize large diameter pipelines, due to the relatively greater impact of diameter on heat flux.[135] TURN appreciates that this issue is confusing, as large diameters decrease the blowdown time (a good thing), but substantially increase potential heat fluxes from a rupture.

Mr. Kuprewicz proposed an alternative decision tree in Figure 11.[136] In addition to using the 24-inch pipe diameter criterion as a cutoff, Mr. Kuprewicz proposed including an additional

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[132] Exh. 21, p. 6-11, A 15, Menegus, PG&E.
[133] Exh. 21, p. 6-9, A 12, Menegus, PG&E.
[134] Mr. Menegus provides an example of a 24-inch pipeline operating at 145 psi. Mr. Menegus agrees this is an unusually low pressure, most likely because this pipeline is at the terminal end of one of the Peninsula lines coming into South San Francisco. 11 RT 1336:11-15, Menegus, PG&E. The other example is a 20-inch line operating at 2,160 psig. This is an exotically high pressure, most likely because this pipeline flows directly from a storage field. 11 RT 1337:2-5, Menegus, PG&E.
[135] Exh. 131, p. 47, Kuprewicz, TURN.
[136] Exh. 131, p. 54, Figure 11, Kuprewicz, TURN.

criterion that determines whether the pipeline is located in sites subject to major earth movement. This is a separate criterion from PG&E's earthquake "active earthquake" crossing decision tree.

4.3.2 PG&E Should Further Investigate Automating Class 1 and 2 HCAs in the Next Phase

Pipeline identified as Class 1 or 2 may also be in an HCA based on the presence of "identified sites," which include locations that are not dwellings (as used in the Class definition) but are places where people congregate.[137] While it is absolutely true that population density is less, survivability in many identified sites due to a rupture would be lower, because high heat fluxes will be longer due to the greater valve spacing in class 1 and class 2 locations.

TURN proposed that all large pipelines (greater than 24-inches in diameter) in such Class 1 and 2 HCA locations also be automated using ASVs with a maximum spacing of 8 miles (class 3 location). Based on PSEP data, TURN calculated that there are 60 miles of such pipeline in HCAs in class 1 and class 2. We had assumed that installing automated valves would thus require about ten valve installations.[138]

PG&E responded by stating that to automate all 80 miles of Class 1 and 2 HCA pipeline (including smaller pipeline) would require over 300 valves to sectionalize 150 pipe segments.[139] PG&E explained that these segments are very short, and apparently are not contiguous and located on multiple different pipes. PG&E claims they have evaluated the actual locations and have concluded that isolating 150 segments would be extremely costly.

Based on this information, TURN does not recommend automating all Class 1 and 2 HCA pipeline. However, we would recommend that PG&E provide additional information

[137] 49 CFR 192.903.
[138] PG&E agreed that to sectionalize 80 continuous miles would require about 10 valves. 11 RT 1339:8-13, Menegus, PG&E.
[139] Exh. 21, p. 6-9, A 13, Menegus, PG&E.

related to HCAs in Class 1 and Class 2, as some may justify valve automation in Phase 1 depending on site specific conditions.

5 Prudence Principles That Must Be Applied to PG&E'S PSEP

5.1 The Commission May Not Allow PG&E to Recover in Rates Costs That Result from PG&E's Imprudence

It is a bedrock principle of public utility law that the "just and reasonable" rates mandated by Section 451 require utilities to demonstrate the reasonableness of proposed costs and require the disallowance from rate recovery of costs arising from utility imprudence.[140] PG&E itself acknowledges that its PSEP costs are not recoverable in rates unless the Commission finds them to be "necessary, useful, and *prudently incurred*."[141]

The longstanding prudency requirement has been codified in Section 463, which notes that it is a "clarification of the existing authority of the Commission."[142] Section 463(a) states in relevant part:

> For purposes of establishing rates for any electrical or gas corporation, the commission *shall disallow* expenses reflecting the direct or indirect costs resulting from any unreasonable error or omission relating to the planning, construction or operation of any portion of the corporation's plant which cost, or is estimated to have cost, more than fifty million dollars ($50,000,000), including any expenses resulting from delays caused by any unreasonable error or omission. Nothing in

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[140] *Investigation on the Commission's Own Motion of the Maintenance and Operating Practices, Safety Standards and the Reasonableness of Costs Incurred from the Mohave Coal Plant Accident, Southern California Edison Company, Respondent* ("Mojave"), D.94-03-048, 53 CPUC 2d 452, 466 ("Commission cases reviewing utility conduct for purposes of reimbursement consistently require that conduct meet a standard of reasonableness."); *see also* Ex. 122 (Long Rebuttal/TURN), pp. 3-4.

[141] Ex. 2 (PG&E Op. Test.), p. 8-5: lines 8-9. TURN's opening testimony of Mr. Long (Ex. 121, pp. 3-5) discussed the need to apply prudence standards to PG&E's PSEP, and, in its rebuttal testimony, PG&E did not challenge the applicability of prudence principles.

[142] Section 463(a).

> this section prohibits a finding by the commission of other unreasonable or imprudent expenses.[143]

Through use of the phrase "shall disallow", Section 463 leaves no doubt that the disallowance of imprudent utility costs is a Commission obligation. Failure to disallow such costs would thus constitute legal error. In addition, Section 463 clarifies that when imprudence is found, the required disallowance extends broadly to direct "or indirect" costs that result from such imprudence.

Section 463(b) addresses the impact of a utility's failure to preserve adequate records and is thus highly relevant to this case. It provides:

> Whenever an electrical or gas corporation fails to prepare or maintain records sufficient to enable the commission to <u>completely</u> evaluate <u>any relevant or potentially relevant</u> issue related to the reasonableness and prudence of any expense related to the planning, construction, or operation of the corporation's plant, the commission <u>shall</u> disallow that expense for purposes of establishing rates for the corporation. This subdivision does not apply where a reasonable person could not have anticipated either the relevance or potential relevance, to an evaluation of costs incurred on the project, of preparing or maintaining the records or the extent of recordkeeping required to adequately evaluate those costs.[144]

In other words, if PG&E has unreasonably failed to prepare or retain records that the Commission needs to evaluate whether any claimed PSEP costs arise from PG&E's imprudence, the Commission <u>is required</u> to disallow such costs. This mandate also applies broadly -- if the absent records would be relevant or even "potentially relevant" to the prudence inquiry. As will be demonstrated below, PG&E's deficient record-keeping is a critical problem that creates tremendous uncertainty about the need for pipeline testing and replacement proposed in the PSEP. Under Section 463(b), such uncertainty must be resolved against PG&E.

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[143] Section 463(a) (emphasis added).
[144] Section 463(b) (emphasis added).

5.2 Absent Competitive Pressures, the Prudence Requirement Is Necessary to Deter Utilities from Engaging in Unreasonable Conduct and Imposing Unreasonable Costs on Ratepayers

The legal requirement to disallow costs resulting from utility imprudence serves important policy goals. The prudence review, in effect, acts as a substitute for absent competitive forces. As one court has explained:

> The principle of prudence has developed in part to counterbalance the monopoly power of public utilities. As one Public Service Commission has observed: 'If a competitive enterprise tried to impose on its customers costs from imprudent actions, the customers could take their business to a more efficient provider. A utility's ratepayers have no such choice. A utility's motivation to act prudently arises from the prospect that imprudent costs may be disallowed.'[145]

Put another way, the threat of disallowance for imprudence acts as a deterrent against imprudent behavior by utilities, thereby reinforcing incentives for the utility not only to comply with applicable requirements, but also to operate their facilities in a safe and prudent manner.[146] Indeed, the Commission has noted that separate penalties and disallowances are possible in response to the same utility behavior.[147]

5.3 As the Operator of Potentially Hazardous Natural Gas Pipelines, PG&E Must Meet a High Standard of Prudence

The Commission has explained the prudence standard as follows:

> The term 'reasonable and prudent' means that 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 the 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

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[145] *Gulf States Utilities Co. v. Louisiana Public Serv. Comm.*, 578 So. 2d 71, 94 fn. 6 (La. 1991) (quoting *Long Island Lighting Co*, 71 P.U.R. 4th 262 (N.Y. Pub. Serv. Comm. 1985); *see also Democratic Central Committee v. Washington Metropolitan Area Transit Authority*, 485 F.2d 886, 906-907 (regulator has a duty to inquire into efficiency to prevent regulated entity from becoming a "high-cost plus profit" company).

[146] Ex. 122 (Long Rebuttal/TURN), p. 4.

[147] *Re Southern California Edison Co.*, D. 93-05-013, 49 CPUC 2d 218, 220.

with good utility practices. Good utility practices are based upon cost effectiveness, safety and expedition.[148]

In applying this standard, the Commission has held that it will expect the utility's managers to exercise "proportionately greater care" to decisions involving large amounts of money, greater levels of uncertainty, or high degrees of risk.[149] Gas pipelines clearly present a high degree of risk to persons and property in that they transport highly flammable and potentially explosive natural gas. Accordingly, PG&E's management of its natural gas pipeline system should be held to a proportionately high standard of prudence.

5.4 Industry Guidelines Are Relevant to the Prudence Inquiry, But Conformity to Industry Practice Does Not Insulate a Utility from a Finding of Imprudence

Typically, the Commission considers evidence of industry practice as part of its analysis of whether a utility has acted prudently. Industry standards, such as the American Society of Mechanical Engineers ("ASME") ASA B31.8 standards for gas pipeline construction, operation and maintenance and B31.8S standards for integrity management,[150] are one way of showing industry practices.[151] Thus, the ASA B31.8 standards are important to the assessment of the prudency of PG&E's management of its pipeline system. In fact, PG&E has previously

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[148] *Mojave*, D.94-03-048, 27 CPUC 2d at 464.
[149] *Re San Diego Gas & Electric Co.,* D.89-02-074, 31 CPUC 2d 236, 246. *See also Re Pacific Gas & Electric Co.* (Helms Pumped Storage Project), D.85-08-102, 18 CPUC 2d 700, 710-711 (where tasks undertaken are of such enormity to expose the utilities and potentially ratepayers to substantial financial risks, utilities must exercise "even greater care and managerial acumen" than would be called for in ordinary circumstances; rejecting view that "marginal" or "average" performance was required and holding PG&E to a "good performance" standard).
[150] In this brief, these two sets of standards will sometimes be collectively referred to as the ASA B31.8 standards.
[151] *Mojave*, D.94-03-048, 53 CPUC 2d at 465.

informed the Commission that it voluntarily follows the ASA B31.8 standards.[152] PG&E's deviation from those standards is clear evidence of imprudent behavior that should trigger disallowances.[153]

On the other hand, where the ASA B31.8 standards are silent, PG&E may not demonstrate prudence simply by presenting expert testimony purporting to show that PG&E's conduct was consistent with industry practice. In *Mojave*, which dealt with a fatal accident resulting from a failed weld in a steam pipe, the Commission held that a showing that the utility's actions were consistent with industry practices did not bind the Commission.[154] The CPUC rejected the utility's argument that the Commission must follow the professional negligence doctrine in some civil courts that defines the standard of care by industry practice. The CPUC reasoned that, whereas lay juries are required to accept the judgment of expert witnesses, the Commission, as an expert agency, is well equipped to evaluate utility actions in highly complex and technical settings and thus can form its own conclusions without the aid of expert opinions.[155] Thus, as will be discussed further below, PG&E should not be able to justify its failure to create or maintain certain records by reference to industry practice, when the evidence shows that such records were necessary for the safe operation and maintenance of PG&E's pipelines.

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[152] *Investigation into the Need of a General Order Governing Design, Construction, Testing, Maintenance and Operation of Gas Transmission Pipeline Systems*, Case No. 6352, D.61269, slip. op., p. 4.
[153] *Id.*, 53 CPUC 2d at 465 ("A utility faces a greater challenge in establishing the reasonableness of its conduct when it fails to act in a manner consistent with industry practice.")
[154] *Id.*, 53 CPUC 2d at 465.
[155] *Id.*, 53 CPUC 2d at 465-466.

5.5 PG&E Has the Burden of Proof to Demonstrate That Its PSEP Costs Do Not Result From Its Imprudence

It is well settled that the utility bears the burden of proof on the issue of prudence and is not entitled to a "presumption of prudence."[156] The utility must carry this burden affirmatively; requests for rate increases that lack sufficient evidence of reasonableness are subject to dismissal.[157]

The fact that the burden of showing prudence rests on PG&E is made even clearer by the extensive record that has already been advanced that PG&E failed to properly construct and manage its gas transmission pipelines, including creating and maintaining the necessary pipeline records. As noted in TURN's testimony,[158] the NTSB Report[159] and the Independent Review Panel Report,[160] document numerous deficiencies, not just with respect to Segment 180 of Line 132, but broader managerial failures with respect to gas pipeline safety, including a lack of management focus on system safety, inadequate data management, deficient threat identification, insufficient staffing, and ineffective quality assurance/quality control.[161] Given this record, PG&E shoulders a heavy burden to demonstrate that the approximately $2 billion of expenditures it seeks to impose on ratepayers are in no way the result of PG&E's managerial

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[156] *Re Pacific Gas & Electric Co.* (Helms Pumped Storage Project), D.85-08-102, 18 CPUC 2d 700, 709-710 (also lamenting that procedure in that case had required Commission staff to "suffer the greatest evidentiary burden," which "handicapped" CPUC's reasonableness review); *Re Southern California Edison Co.*, D. 93-05-013, 49 CPUC 2d 218, 220.
[157] *Re Southern California Edison Co.*, D.86-10-069, 22 CPUC 2d 124, 150 (also noting that procedures in the future should place less reliance on the showings of the CPUC staff and intervenors and more emphasis on utilities' direct showings).
[158] Ex. 121 (Long Opening Test./TURN), pp. 4-5.
[159] National Transportation Safety Board, Pipeline Accident Report**,** Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010 ("NTSB Report"), adopted August 30, 2011.
[160] Report of the Independent Review Panel, San Bruno Explosion ("IRP Report"), Prepared for California Public Utilities Commission, revised copy, June 24, 2011.
[161] IRP Report, pp. 7-13.

failures. The Commission must find that PG&E has met this burden before any dollar of PSEP costs may be approved for rate recovery.

5.6 PG&E's Cost Responsibility Principles Can and Should Be Adapted to Comport with Prudence Requirements

PG&E proposed that the Commission use two principles to determine the allocation of PSEP costs between ratepayers and shareholders:

> 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.
>
> 2. To the extent an activity must be undertaken in the PSEP to comply with preexisting regulatory requirements, PG&E will <u>not</u> seek cost recovery for such activities in the PSEP.[162]

In response to TURN's cross examination regarding the second principle, PG&E's Senior Vice President Tom Bottorfff clarified that PG&E considers Section 451 to be a "preexisting regulatory requirement."[163] He further testified that Section 451 "includes discussion and description of prudence."[164] In light of this testimony, it appears that PG&E and TURN may be in agreement on how prudence requirements should be used to assess responsibility for PSEP costs. If PG&E's second principle is clarified to apply to PSEP activities that are undertaken to "comply with preexisting regulatory requirements, *including prudence obligations,*" then TURN would agree that the principle is a good way to frame the prudence inquiry in this case.[165]

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[162] Ex. 21 (PG&E Rebuttal), p. 1-1: 27-33 (emphasis in original).
[163] Tr., vol. 8, p. 816: 3-10 (Bottorff/PG&E).
[164] Tr., vol. 8, p. 816: 27 – 817: 9 (Bottorff/PG&E).
[165] Even if PG&E's opening brief were to disagree with TURN's understanding of Mr. Bottorff's above-quoted testimony, TURN would still recommend that PG&E's principle, as clarified by TURN, be used as a cost responsibility principle in this case.

PG&E's rebuttal testimony provides a useful interpretation of the second principle. PG&E states that, under the second principle, "it is fair to ask the question 'would PG&E have been obligated to do the work if D.11-06-017 had never been issued?'"[166] PG&E further states: "If the answer if yes, PG&E is doing the work under the PSEP to come into compliance with a pre-existing regulatory requirement and shareholders should pay for the work."[167] As with PG&E's second principle, TURN would recommend that this useful interpretative standard be understood to include work that PG&E would have been obligated to do *under prudence requirements*.

In sum, TURN would recommend the following as an appropriate principle for the Commission to apply in order to comply with its prudence-related obligations under Sections 451 and 463:

> To the extent an activity must be undertaken in the PSEP to comply with preexisting regulatory requirements, including prudence obligations, PG&E may not obtain cost recovery for such activities in the PSEP. PG&E bears the burden of proving that, absent D.11-06-017, PSEP activities would not have been undertaken to comply with such preexisting regulatory requirements.

6 Application of Prudence Principles to PG&E's PSEP

6.1 The Full Cost of PG&E's Proposed Pipeline Modernization and Valve Replacement Programs Should Be Disallowed From Rate Recovery

Based on the NTSB and IRP Reports, there can be no dispute that the San Bruno explosion exposed not just serious safety failures with respect to Segment 180 of Line 132, but major systemic problems at PG&E that need to be fixed. With respect to cost responsibility, the findings and recommendations of the NTSB and IRP make a strong case that the main purpose of

[166] Ex. 21 (PG&E Rebuttal), p. 1-12: 18-19.
[167] Ex. 21 (PG&E Rebuttal), p. 1-12: 19-22.

the PSEP is to bring the gas transmission system to the level of safety that PG&E is required to provide under Section 451 and well established prudence principles.

PG&E's second cost responsibility principle, as clarified above, frames well the threshold question for the Commission: would PG&E have been obligated, under specific regulatory requirements *and prudence principles*, to do the work that it proposes in its PSEP if D.11-06-017 had never been issued? Administrative Law Judge ("ALJ") Bushey recognized the importance of this question. In overruling an objection from PG&E's counsel, she stated:

> Mr. Long is well within his rights to ask what does that mean. If the decision hadn't been issued, what does PG&E perceive its obligations to have been, because that is the critical fact that we're trying to get at with this testimony.[168]

TURN posed that question to the two PG&E officers who testified for the company, Tom Bottorff and Nick Stavropoulos. Their answers provide two different – and compelling -- grounds for disallowing the full costs of the PSEP.

6.1.1 PG&E's Pipeline 2020 Program Shows That PG&E Needed to, and Would Have, Implemented the Same Pipeline and Valve Programs In the Absence of D.11-06-017

First, Mr. Bottorff testified that, after the San Bruno explosion and in the absence of D.11-06-017, PG&E "would have, and . . . did" take certain actions. In particular, Mr. Bottorff highlighted that PG&E had proposed the Pipeline 2020 program in October 2010 to "address some of the issues" that PG&E identified after the explosion.[169] According to PG&E, the goal of the program was to "strengthen and modernize the gas transmission system such that every pipeline segment would have a documented margin of safety."[170] Pipeline 2020 thus provides a

[168] Tr., vol. 8, p. 821: 7-12.
[169] Tr., vol. 8, pp. 821:24 - 822: 5 (Bottorff/PG&E).
[170] Ex. 33 (CCSF cross exhibit: PG&E DR CCSF 5-5).

good indication of the remedial work that PG&E felt was necessary in order to make its gas transmission system safe.[171]

Data request responses from PG&E show that the PSEP Pipeline Modernization and Valve Automation Programs have the same scope and design as Pipeline 2020. One response explains that Pipeline 2020's plan for safety would require "every segment to have a verifiable pressure test" and that untested pipelines would "either be pressure tested or replaced . . .."[172] This is precisely what the Commission ordered in D.11-06-017 and what PG&E designed its PSEP Pipeline Modernization Program to accomplish. Moreover, like the PSEP, Pipeline 2020 had decision trees for threats from manufacturing, fabrication and construction, and corrosion and latent mechanical damage.[173] Furthermore, PG&E's data request response states that Pipeline 2020 "formed the basis for" the PSEP's Pipeline Modernization Program and that the Phase 1 scope of pipeline projects between Pipeline 2020 and the PSEP "has remained essentially unchanged."[174] Likewise, another PG&E data request response indicates that: the valve automation program in Pipeline 2020 "formed the basis for" the PSEP Valve Automation Program; there were "only minor adjustments" to the valve program made from Pipeline 2020 to the PSEP; the PSEP valve decision trees are identical to those in Pipeline 2020; and 80 identified Phase 1 valve installation sites in the PSEP are the same in both programs.

It is therefore clear that PG&E's response to the San Bruno explosion was to design pipeline and valve programs that the explosion showed were needed but, tragically, not in place

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[171] ALJ Bushey advised counsel for TURN to focus on Pipeline 2020 in his cross examination "because it seems like that's where they listed out everything they felt they were obligated to do and that came up before the decision [11-06-017] . . .." Tr., vol. 8, p. 823: 10-15.
[172] Ex. 33 (CCSF cross exhibit: PG&E DR CCSF 5-5).
[173] *Id.* In fact, Pipeline 2020 had decision trees for three other threats, but those were dropped in the PSEP. *Id.*
[174] *Id.*

for PG&E's gas transmission system. In proposing such remedial work, PG&E was effectively acknowledging the serious shortcomings in its management of the system – *i.e.,* its imprudence - and that major changes were needed to rectify that imprudence. Accordingly, under the prudency principles embodied in Sections 451 and 463 and PG&E's own second cost responsibility principle, PG&E should not be allowed to impose on ratepayers <u>any</u> of the PSEP's pipeline and valve costs, as those are costs that are needed to remedy PG&E's imprudence and that PG&E would have needed to incur in D.11-06-017 had never been issued.

PG&E takes the position that none of the work in the PSEP is designed to remedy its errors or omissions. On its face, this is an implausible claim in light of the serious problems in PG&E's integrity management program, quality control and record-keeping indentified by the NTSB and the IRP. After such a deadly explosion that has been shown to result from systemic management failures, it defies logic to argue that the PSEP has nothing to do with fixing PG&E's mistakes and is only being proposed because the CPUC imposed new minimum requirements in D.11-06-017.

In an attempt to escape responsibility for its imprudence, PG&E seizes on the determination in D.11-06-017 that California gas utilities may not justify maximum allowable operating pressure ("MAOP") based on historic operating pressures under the "grandfathering" provision of 49 C.F.R. Section 192.619(c). However, PG&E wrongly views the <u>minimum</u> regulatory requirements of the federal regulations[175] and General Order ("GO") 112[176] as establishing its sole obligation. PG&E dangerously ignores its independent, and in this case, more demanding obligations under Sections 451 and 463 to operate its gas system safely and

[175] 49 C.F.R. Section 192.1.
[176] Ex. 54 (GO 112), Section 102.1

prudently, commensurate with the risks of transporting flammable and explosive natural gas. D.11-06-017 makes it clear to California's gas utilities that reliance on the grandfathering provision is not consistent with the Section 451 requirement "to promote the safety, health, comfort, and convenience of utility patrons, employees and the public," a requirement that has been constant in the history of California public utility regulation.[177] In other words, PG&E is incorrect when it contends that D.11-06-017 changed its regulatory obligations. Under Sections 451, 463 and prudence requirements, PG&E has always been obligated to operate its pipelines at safe operating pressures and to be able to document that safety margin in reliable records readily available to itself and its regulators.[178] As PG&E recognized with its Pipeline 2020 Program, it was not meeting that obligation at the time of the San Bruno explosion, and it needed to implement a major corrective program to remedy that failure. The PSEP is that corrective program, and its costs should not be imposed on ratepayers.

6.1.2 PG&E Failed to Sustain Its Burden of Proving That It Would Not Need to Pursue the PSEP If D.11-06-017 Had Not Been Issued

Even if the Commission does not conclude that the Pipeline 2020 Program demonstrates the need for a full disallowance of the PSEP pipeline and valve costs, PG&E's testimony supplies another reason for such a disallowance.

Despite the fact that PG&E presented the question -- would PG&E have been obligated to do the PSEP work absent D.11-06-017? -- in its written policy testimony,[179] their policy witness and one of the sponsors of that testimony, Mr. Stavropoulos, professed to be unable to explain

[177] D.11-06-017, p. 18.
[178] Below, in section 6.3.4, we will address PG&E's contention that the insistence that its pipeline records be traceable, verifiable, and complete imposes a new regulatory requirement.
[179] Ex. 21 (PG&E Opening/Bottorff and Stavropoulos), p. 1-12, Q&A 26.

what activities PG&E would have felt the need to pursue if D.11-06-017 had never been issued. Mr. Stavropoulos found the question "interesting", but said he hadn't "spent any time thinking" about it – he concluded, "we haven't given any thought to that question."[180]

This testimony perfectly captures PG&E's complete failure to meet its burden of proof on prudence issues. It was PG&E's obligation to prove its (highly implausible) assertion that none of the PSEP activities would have been necessary in the absence of D.11-06-017. To support this contention, one would at least expect PG&E's policy witnesses to testify unequivocally that, absent D.11-06-017, PG&E would not need to perform any PSEP work to fulfill its safety obligations. To their credit, Mssrs. Bottorff and Stavropoulos were uncomfortable making such an indefensible claim. Instead, they chose to sidestep the question. The inability of PG&E's top witnesses to support the company's key cost responsibility argument is telling.

In light of PG&E's failure to sustain its burden of proof that the PSEP is not remedial in nature, the Commission can and should find on this record that none of the PSEP costs may be recovered from ratepayers.

6.2 If the Commission Does Not Decide Now to Fully Disallow PSEP Costs, An Issue-by-Issue Analysis Shows that a High Proportion of the Pipeline Modernization Costs Should Be Disallowed Based on the Current Record

Notwithstanding the foregoing, if the Commission does not disallow all of the PSEP costs at this time, it should conduct an issue-by-issue analysis to determine which of the Pipeline Modernization ("PM") costs should be disallowed.[181] Such analysis, set forth below, shows that a high proportion of such costs are designed to remedy PG&E's past imprudence and should be

[180] Tr., vol. 8, pp. 825: 11 – 828:4.
[181] TURN separately discusses the cost responsibility issues for the proposed Pipeline Records Integration Program in Sections 6.3 and 6.4 below.

disallowed based on the current records. As will be discussed in Section 6.5 below, the issue of whether the remaining PM costs are appropriate for rate recovery should not be addressed until the Commission has a complete record from the three enforcement OIIs regarding PG&E's past imprudence.

In the following sections, TURN quantifies, for illustrative purposes, the cost results of proposed disallowances and adjustments by using the applicable mileage from the PSEP database[182] multiplied by the applicable average unit costs in PG&E's cost forecasting models, which are $4.5 million per mile for replacement, and $0.5 million per mile for hydrotesting.

6.2.1 Pipeline Costs Should Be Disallowed for Segments Where PG&E Lacks Records of Hydrotests That Were Required by Regulations or Industry Standards.

Beginning in 1955, ASA B31.8 industry standards specified that newly installed pipeline must be strength tested before the pipeline could go into service and that records of such pressure tests must be preserved.[183] In 1961, this requirement was embodied in GO 112,[184] and in 1970, federal regulations imposed a similar obligation, with more detailed record-keeping requirements.[185]

By virtue of its prudence and Section 451 obligations, PG&E is thus obligated to have accurate and reliable test records of hydrotests for all pipelines or pipe segments it installed from

[182] The PSEP database is in the record as Exhibit 60.
[183] Ex. 143 (DRA/Pocta), Appendix A, pp. 11-12. The 1955 version of B31.8 specified that a record of the test pressure and test fluid shall be preserved for the useful life of each pipeline.

[184] GO-112 likewise required maintaining records of strength test fluid and pressure for any pipeline intended to be operated at more than 20% SMYS, as well as maintaining the "specifications covering the pipe selected for installation." Exh. 54, Section 401.2.
[185] 49 CFR 192.517 requires, for pipelines intended to be operated at more than 100 psi or at or above 30% SMYS, maintaining records of seven specified items for the useful life of the pipeline. PG&E has chosen four of those items as its definition of a "complete" record to be applied to pipeline installed in any year.

1955 on. Under PG&E's second cost responsibility principle and established prudence principles, to the extent PG&E is proposing work in the PSEP -- either testing or replacement of pipeline segments – that results from PG&E's failure to possess such records, the cost of such work should be disallowed. This principle is further dictated by Section 463(b), which, as previously noted, requires the disallowance of any costs the prudence of which cannot be completely evaluated because of the utility's failure to prepare or maintain records.

Because PG&E's position on the disallowance of such costs varies by time period, we will analyze this issue for each relevant period of time.

6.2.1.1 Pipeline Installed from 1970 to the Present

Hydrotesting Costs. Under PG&E's second principle, PG&E's written testimony agrees that its shareholders should pay for the costs to hydrotest any post-1970 segments. PG&E estimates that from 2012 through 2014, such costs will total $11.8 million.

Replacement Costs. Unaddressed in PG&E's written testimony is whether shareholders will pay for the 9 miles of pipeline installed in 1970 or later that PG&E proposes to replace.[186] However, as discussed in the next section, Mr. Bottorff testified at hearing that shareholders should pay for any costs to replace post-1961 pipeline for which PG&E lacks a verifiable test record.[187] Thus, based on that testimony, and for the reasons discussed in the next section, PG&E shareholders should be responsible for the approximately $40.5 million in capital costs to replace those 9 miles of pipeline.

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[186] Mileage data derived from PG&E's PSEP database, Exh. 60 in the record.

[187] Tr., vol. 8, p. 854: 14-27 (Bottorff/PG&E).

6.2.1.2 Pipeline Installed from 1961-1970

Hydrotesting Costs. PG&E has admitted that CPUC standards pursuant to GO 112, adopted in 1961, required the company to keep relevant strength test records that would allow validation of the MAOP. As a result, PG&E has agreed to pay for the hydrostatic testing of pipeline that was placed into service between July 1, 1961 and November 12, 1970, where strength test documentation is missing.[188] PG&E has estimated there are 32 miles of such pipeline scheduled for hydrotesting in the PSEP.[189]

TURN agrees with and accepts PG&E's conclusion that shareholders should pay for this pipeline testing. However, there are two problems with PG&E's calculation of 32 miles subject to shareholder contribution. First, as explained in DRA's testimony,[190] PG&E has allocated to shareholders only those segments with an "incomplete record" in the database. Instead, PG&E should allocate to shareholders segments that have anything *other than* "complete record." The difference is significant, since there are actually approximately 100 miles of pipeline installed in 1961-1969 with less than a 'complete record,' as shown in Table 2 below:

Table 2: Pipeline Installed in 1961-1969 scheduled for Testing[191]

Result in "MAOPrec430" field regarding pressure test records[192]	**Pipe Miles**
Incomplete Record	33.0
Partial Mileage	22.7
Complete	14.9
(blank field)	42.9
Total	**113.5**

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188 Exh. 21, p. 1-12:1-5, Bottorff/Stavropolous, PG&E and p. 3-14, Hogenson, PG&E.

189 Exh. 21, p. 1-18:1-4, Bottorff/Stavropolous, PG&E. PG&E estimates the resulting cost at $32-48 million, and PG&E intends to determine the proper cost allocation "during our PSEP project data validation process." Exh. 21, p. 3-14:33-35, Hogenson, PG&E.

190 Exh. 144, DRA-03, p. 83, Roberts, DRA.

191 Source: PSEP Database queried for install date 1961-1969.

192 These fields are explained in Exh. 144, p. 83, Roberts, DRA.

Based on these numbers, PG&E's cost responsibility for hydrotesting 1961-1970 pipelines should be closer to $49.3 million.[193] Supposedly, PG&E's final MAOP Validation, which will only have two categories, should resolve this problem.

Second, as discussed in Section 3.4.4 above, PG&E has selected for hydrotesting pipeline that may have been tested previously but is missing any one of the *four record elements* chosen by PG&E. PG&E's proposal is to have shareholders pay for testing any pipeline that is missing one of the *three record elements* required by GO-112. [194] However, if test records contain all three elements required by GO-112 *but are missing only the name of the operator,* PG&E would have ratepayers pay for the strength testing.[195]

This is a perverse outcome. PG&E has arbitrarily chosen an additional record element that has no apparent impact on safety, and in contravention of Ordering Paragraph 3 of D.11-06-017, and now proposes that ratepayers pay for this deficiency. As explained previously, PG&E does not have data on pipeline mileage that is only missing the operator name.

The Commission should order PG&E to 1) identify the mileage installed in 1961-1970 that is slated for testing *only* due to the lack of operator name in the records, and 2) either exclude testing of this pipeline from Phase 1 or require shareholders to pay for such testing. If PG&E lacks the necessary records to identify this mileage, then under Section 463(b), all of the costs of testing pipeline installed from 1961 to 1969 should be disallowed.

Replacement Costs. While PG&E has agreed that it should pay for testing any pipeline installed after July 1, 1961 without adequate records to comply with GO 112, PG&E is less than

[193] Calculated by summing all elements from Table 2 that are not "complete," for a total of 98.6 miles, and multiplying by the unit hydrotest cost of $0.5 million per mile.
[194] Exh. 21, p. 3-14:26-30, Hogenson, PG&E.
[195] Exh. 21, p. 3-14 and 11 RT 1479-1481, Hogenson, PG&E.

clear on whether shareholders will cover the cost of replacing pipelines installed after July 1, 1961 without proper records of a strength test.

In its response to CPSD and its rebuttal testimony, PG&E only specifies that shareholders will "bear responsibility for hydro testing." PG&E makes no mention of paying for pipeline replacement. PG&E has identified approximately 25 miles of pipeline installed in 1961-1970 that are scheduled for replacement in Phase I.

At hearing, PG&E's highest-ranking testifying officer, Mr. Bottorff, testified that PG&E shareholders <u>will</u> cover the cost of replacing the pipeline installed in 1961-1970.

> Q And is PG&E planning to pay for any costs for replacing pipeline that was installed after 1961 that may be missing strength test records?
>
> WITNESS BOTTORF: A If it had the records or the testing results that were required under that standard then, to the extent the decision called for subsequent replacement or testing, then we would recover those costs from customers. *If we didn't have the proper test results that were in compliance with standards in effect at that time, then those costs would be borne by our shareholders*.[196]

Mr. Bottorf's answer was fully consistent with PG&E's own second cost responsibility principle and is the correct answer under prudence principles. The replacement work would be undertaken because PG&E lacks the strength testing records it was required to create and maintain and should therefore be paid for by shareholders.

However, Mr. Bottorf's testimony was contradicted by Mr. Hogenson, who testified that PG&E <u>will not</u> accept responsibility for pipe replacement for pipeline installed in 1961-1970.[197]

There is no relevant difference between testing and replacement that warrants different cost responsibility treatment. Any pipe that PG&E has scheduled for testing *or* replacing in Phase 1 is included because PG&E lacks the requisite records. PG&E has agreed it should have

[196] Tr., vol. 8, p. 854: 14-27 (Bottorf/PG&E) (emphasis added).
[197] 11 RT 1415:2-11 and 1484-1488, Hogenson, PG&E.

created and retained such records. Whether the pipe is now being replaced or tested is absolutely immaterial to the question of whether PG&E should have retained valid records.

Mr. Hogenson argued that there is a substantive difference because:

> [P]ipeline segments are being replaced for other reasons than lack of pressure test. You are looking at the manufacturing threats, how the pipe was manufactured, the type of pipe, type of long seam it might have had, as well as any fabrication or construction threats that might exist.[198]

Mr. Hogenson's arguments logically conflicts with PG&E's own decision tree. The decision to test or replace is *not driven* by fundamental differences in threat assessment. Mr. Hogenson's explanation ignores the fact that, *before* any decision to test or replace is made, PG&E's decision tree *first* checks on the existence of complete records of a valid strength test. It is the presence or absence of those records that determines future work. If a test had been conducted and all the records required by GO-112 are present, then, under D.11-06-017, the pipeline would not need to be tested or replaced, irrespective of the presence of any identified threats.[199]

And if records are missing, the decision whether to test or replace is *not* driven by the existence of any particular threat or pipeline characteristic.

An example from PG&E's manufacturing threat decision tree illustrates the errors in Mr. Hogenson's explanation. The test for various manufacturing threats and pipe characteristics occurs first (in Steps 1E, 1F and 1G), *before* any consideration of whether to test or replace. The outcome of those decision tree steps *does not* impact the question of whether to test or replace. Rather, all pipelines with potential manufacturing threats that lack records flow through Step 1H

[198] 11 RT 1415:4-11, Hogenson, PG&E.
[199] Mr. Hogenson agreed that this is the logic flow of the decision tree. 11 RT 1483:24-1484:12.

and into Step 1J. The decision whether to test or replace is determined entirely by the outcome of Step 1J, which uses the criterion of whether the pipe operates at above or below 30% SMYS. Pipelines in populated areas operating at ≥30% SMYS will be replaced, while pipelines in populated areas operating below 30% SMYS will be strength tested.[200]

Similarly, the decision whether to test or replace in the Fabrication & Construction Threat decision tree does not depend on the presence of certain construction threats. For example, all pipeline with threats evaluated in Step 2E will flow to Step 2F. If test records are missing, the decision to replace or strength test depends entirely on class location in Step 2G.

The result is that PG&E's proposal allocates cost responsibility between shareholders and ratepayers based strictly on whether the pipeline operates at above or below 30% SMYS (for manufacturing threats) or is present in populated areas (for fabrication and construction threats), not based on any actual substantive pipeline characteristics.[201] These criteria lack any rational basis as a principle for allocating cost responsibility. TURN recommends that the Commission consistently apply the actual principle that PG&E itself articulates – if PSEP work results from PG&E's failure to meet its obligations, then PG&E should pay for the work. With the complete test records required by GO 112, a pipeline would not need to be tested or replaced, irrespective of the presence of any threats.

Moreover, PG&E's position creates bad incentives. If hydrotesting costs are disallowed but replacement costs are recovered in rates, then PG&E has a strong incentive to skew its work

[200] As discussed in Section 3.5.2, TURN disagrees with PG&E's decision to automatically replace all pipelines operating above 30% SMYS.

[201] Mr. Hogenson agreed that this was the result of his recommendation. 11 RT 1488:12-22. Mr. Hogenson at first argued that the difference was due to the company's decision to replace "50-year-old pipeline," but later admitted that for pipeline of the same age installed in 1961-1970, the difference is driven strictly by whether, for example, the pipeline operates at above or below 30% SMYS. 11 RT 1488.

toward replacement, even if testing is all that is needed. (Better put, PG&E would have an even stronger incentive, in that most replacement costs are capital expenditures on which PG&E would be able to collect a rate of return.) This is another reason why hydrotesting and replacement costs that result from PG&E's errors should be treated the same.

PG&E calculated that approximately 25 miles of pipeline installed in the 1960's are slated for replacement.[202] However, once again, PG&E appears to be using only the numbers reflecting the "incomplete" record element. PG&E shareholders should pay for all pipeline without complete records, which amounts to approximately 27 miles. Accordingly, based on the current record, approximately $121.5 million in capital costs[203] for replacement of pipeline installed from 1961-1970 should be disallowed from rate recovery.

6.2.1.3 Pipeline Installed from 1955-1961

With respect to pipeline installed between 1955 (when ASA B31.8-1955 was promulgated) and 1961 (when GO 112 went into effect), PG&E opposes shareholder responsibility for PSEP costs even to hydrotest pipe segments for which PG&E should have records of strength tests under the B31.8 industry standards. PG&E cites as an example of costs that customers should pay a 1959 pipe segment for which it is missing complete records of a hydrotest. PG&E argues that D.11-06-017 requires hydrotesting for the first time because PG&E was not previously required to strength test the segment under GO 112 or the federal "grandfathering" rule.[204]

PG&E's position is based on its incorrect view that GO 112 and federal regulations supply the only source of obligations for the company. As previously explained, Section 451

202 Exh. 28, PG&E Response to TURN 17-01.
203 27 miles multiplied by unit replacement cost of $4.5 million per mile.
204 Ex. 21 (PG&E Rebuttal/ Bottorff and Stavropoulos), pp. 1-12 to 1-13 (Q&A 27).

and prudence principles required PG&E to follow the B31.8 industry standards. PG&E does not deny that the 1955 standards reflected prudent industry practice; PG&E was even represented as a Subgroup Chairman on the committee that adopted the standard.[205] Moreover, PG&E stated in a data request response that it believes that, after adoption of ASA B31.8-1955, PG&E's practice was to follow those standards.[206]

The 1955 standards required keeping records of a hydrotest pressure and test medium. Pursuant to Ordering Paragraph 3 of D.11-06-017, any test record containing these elements should thus be sufficient to justify eliminating this pipeline from Phase 1 testing.

In light of this record, there can be no doubt that PG&E was required to follow the ASA B31.8 strength testing and record-keeping requirements as part of its Section 451 and prudence obligations. Accordingly, for the reasons set forth in the previous (1961-1970) section, PG&E shareholders should be responsible for all PSEP costs to test or replace 1955-1961 pipeline segments for which PG&E lacks accurate records of the pre-service strength tests required by ASA B31.8-1955.

There are approximately 90 miles of 1956-1960 pipeline scheduled for testing in Phase 1, representing a disallowance of approximately $45 million in expenses.[207] There are approximately 18 miles of pipeline scheduled for replacement in Phase 1, representing a capital disallowance of $81 million.

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[205] Ex. 143 (DRA/Pocta), Appendix A., p. 9.
[206] Ex. 143 (DRA/Pocta), p. 23.
[207] Exh. 60. Mileage calculated from PSEP database using all pipe install dates 1956-1960.

6.2.2 Pipeline Modernization Costs that Result from PG&E's Failure to Follow Integrity Management Requirements Should Be Disallowed.

The available evidence indicates that, under integrity management requirements, PG&E should have in-line inspected or hydrotested up to about 300 miles of pipeline now included in the PSEP. PG&E has agreed that pursuant to its stated policy governing cost responsibility, shareholders should pay for PSEP work resulting from a failure to properly perform integrity management.[208] As explained below, PG&E failed to use its intended primary assessment method of in-line inspection ("ILI") to assess most of its pipeline segments, and instead relied heavily on direct assessment methods, which are limited by federal regulations to assessing corrosion threats.

The Commission should thus disallow approximately $40 million of PSEP ILI costs, about $120 million in PSEP hydrotest expenses and $279 million in PSEP replacement capital.

6.2.2.1 PG&E Intended to Rely on In Line Inspections to Assess Pipelines for Manufacturing and Construction Threats

The federal Gas Transmission Integrity Management Program ("TIMP"), as codified in Subpart O of Part 192 of the Code of Federal Regulations, required PG&E, beginning in 2004, to identify threats on all HCA pipelines using all available record evidence and to assess those threats using one of four methods.[209]

As required, PG&E developed a Baseline Assessment Plan by the end of 2003 ("BAP 2004"). In the first BAP 2004, PG&E identified 457 miles of pipeline with a manufacturing

[208] RT 794: 17 – 795:1, Bottorff, PG&E.
[209] 49 CFR 192.921(a). See, also, Exh. 131, p. 77-80, Kuprewicz, TURN.

threat.[210] PG&E developed various documents to guide its Integrity Management procedures,[211] including the integrity management program contained within Risk Management Procedure 06 ("RMP-06"), created to comply with Part 192.907. RMP-06 indicates that PG&E intended to use ILI for assessing manufacturing threats "whenever it is physically and economically feasible."[212] PG&E decided from the outset to exclude pressure testing as an assessment method:

> Sec. 5.2. Background: The Company will choose the method or methods best suited to assess the identified threats to the HCA. These methods may include 1) In-line inspection tools … 2) Pressure testing 3) Direct assessment. …
>
> Sec. 5.4 Inline Inspection: It is the Company's **desire to inspect pipelines utilizing In-Line Inspection** (ILI), whenever it is physically and economically feasible. …
>
> Sec. 5.5. Pressure Testing: **The Company does not plan to use pressure testing** to assess the integrity of its pipelines. However, during the course of assessing data for ECDA or ILI, it may become apparent that pressure testing is the only feasible option. If so, the Company will perform a pressure test following the requirements found in Company's Gas Standards and Specifications A-37.
>
> Sec. 5.6. Direct Assessment: Direct Assessment assesses integrity by the use of a structured process to integrate knowledge of the physical characteristics and operating history of a pipeline with results of inspection, examination and evaluation. **It can be used as a primary method only for external and internal corrosion, and stress corrosion cracking**. It may also be used as a supplement to other methods.[213]

Thus, at the **very outset** of integrity management PG&E had decided to rely primarily on ILI and not hydrotesting. PG&E acknowledged that ECDA was **not an appropriate primary assessment method** for threats other than corrosion.

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[210] Exh. 71, 2004 BAP Summary. This number was reduced to 400 miles in the 2009 BAP due to changes in class location or pipeline status. The 2009 BAP data is contained in Exh. 137, Attach. 8B.
[211] A convenient summary is provided in the NTSB Accident Report. NTSB Accident Report, Sec. 1.9.4.2, p. 61-63.
[212] Exh. 104, PG&E's RMP-06, 8/31/11, Sec. 5.4, p. 42.
[213] Exh. 104, PG&E RMP-06, Rev. 7, 8/31/11. This document is in the record in I.11-02-016 as document P2-371. The identical wording is contained in prior revisions. These documents are marked as exhibits P2-372 to P2-376 in I.11-02-016.

The language quoted above from Section 5 of the 2004 RMP-06 is repeated verbatim in every revision of RMP-06 in 2005-2010.[214]

6.2.2.2 PG&E Failed to Follow Its Own Procedures to Use In Line Inspections for Threat Assessment and Instead Relied Primarily on Direct Assessment

In practice, however, PG&E failed to use ILI properly to assess threats. Instead, PG&E relied predominantly on direct assessment methods, including external corrosion direct assessment ("ECDA"), to assess HCA pipelines. During 2002-2010 PG&E assessed 649 miles of HCA pipeline using direct assessment, 171 miles using ILI and only 14 miles using hydrotesting.[215] All of Line 132 was assessed exclusively with ECDA.[216]

PG&E should not have used ECDA as the primary method for pipelines with manufacturing threats. Federal regulations limit the use of direct assessment as a primary method to address external corrosion, internal corrosion and stress corrosion cracking.[217] Direct assessment, including ECDA, is not the proper method to assess the risk of manufacturing or construction defects. PG&E's own procedures explain that ECDA is used to evaluate external corrosion and third party damage risks.[218] The primary assessment methods for manufacturing or construction threats are hydrostatic strength testing and in-line inspection. Non-destructive examination can also be used on exposed pipeline.

As discussed in detail in Section 7.5 below, there is significant evidence in the Overland Audit Report that PG&E reduced ILI work in 2008-2010 due to cost cutting. PG&E changed the planned assessment of pipelines from ILI to ECDA and PG&E deferred projects in order to meet

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[214] These documents are marked as exhibits P2-372 to P2-376 in I.11-02-016.
[215] Exh. 1, Table 2-5, p. 2-17, Hogenson, PG&E.
[216] NTSB Report, p. 66; and 12 RT 1545, Hogenson, PG&E.
[217] 49 CFR 192.921(a)(3).
[218] PG&E's RMP-06, Sec. 5.6; PG&E's RMP-09, Sec. 2.1.

reduced annual authorized budgets. A 2010 CPUC audit of PG&E's integrity management likewise noted these deferrals and changes, and also highlighted concerns that PG&E may be "diluting the requirements of the [integrity management program] through its exception process and appears to be allocating insufficient resources to carry out and complete assessments in a timely manner."[219]

Additionally, PG&E failed to properly assess the potential impacts of cyclic fatigue and threat interactions on pipelines with identified manufacturing threats, as required by integrity management regulations and industry protocols.

6.2.2.3 PG&E Shareholders Should Pay for Replacing 62 Miles of Pipeline and Hydrotesting 239 Miles of Pipeline Inappropriately Assessed in Integrity Management

PG&E now plans to test or replace 301 miles of the 400 miles of pipeline with manufacturing threat as part of its Phase I Pipeline Safety Enhancement Plan ("PSEP").[220] Of the 185 miles scheduled for replacement in Phase I of the PSEP, 62 miles had a manufacturing threat identified in the 2009 BAP, including 20 miles installed after 1955. Of the 783 miles scheduled for hydrotesting in Phase I, 239 miles had a manufacturing threat identified in the 2009 BAP, including 62 miles installed after 1955.[221]

PG&E should have performed a different assessment on the 400 miles of HCA pipeline in the 2009 BAP with identified manufacturing threats, including the 301 miles now included in

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[219] See, NTSB Report, Sec. 1.10.1, p. 68.
[220] TURN compared segments in the PSEP with an electronic version of the 2009 BAP (Exh. 137, Attach. 8B). These calculations are included in TURN's testimony submitted in I.12-01-007.
[221] Due to database issues, TURN could only compare the contents of the PSEP with the 2009 BAP. As noted above, the 2009 BAP in total contained about 60 miles less pipeline with identified manufacturing threat than the 2004 BAP.

the PSEP Phase I (239 for testing and 62 for replacement).[222] PG&E shareholders should be responsible for the costs of testing or replacing these 301 miles of pipeline due to violations of integrity management.[223] The Commission should thus disallow about $120 million in hydrotest expenses and $279 million in replacement capital.[224]

As discussed in Section 7.5, the Commission should also find that the money spent on direct assessments in 2004-2010 should be disallowed as deferred maintenance, since it was wasted ratepayer money, given that PG&E is now going to have to test or replace the same pipe it already inspected using ECDA.

6.2.2.4 PG&E Should Have Hydrotested the Pipelines Which It Pressure Spiked to Evade the Requirements for Hydrotesting

Even if the Commission does not find PG&E shareholders responsible for paying for all of the testing or replacement of pipelines with manufacturing threats not properly assessed during integrity management, at a minimum PG&E should be responsible for the costs of pipeline now included in the PSEP which it spiked during 2003-2010. The data submitted in

[222] TURN has not completely evaluated the BAP database to determine whether PG&E had ILI'ed some of these 300 miles. However, PG&E would still have had to appropriately use TFI in-line inspection to test for seam weld defects.

[223] Additionally and as a separate rationale, PG&E shareholders should cover the costs of testing and replacing the 82 miles installed after 1955 due to violation of industry standards, which required hydrotesting upon installation and the maintenance of certain test records.

[224] This recommendation overlaps with the recommendations to disallow costs for pipelines installed after 1955 due to record-keeping issues. The disallowance for integrity management imprudence related *only* to pipelines installed pre-1956 would be $189 million capital (replacing 42 miles) and $88.5 million expense (testing 177 miles).

I.12-01-007 indicate PG&E should be responsible for hydrotesting costs for approximately 32 miles of pipeline, and replacement costs for approximately 20 miles of pipeline.[225]

TIMP regulations specify that an operator must consider a manufacturing threat as unstable if there is an increase in pressure above the MAOP or above the maximum operating pressure in the five years preceding HCA identification.[226] Pursuant to Part 192.917(e)(3) and ASME B31.8S, such pressure increases would have triggered the need to perform a hydrotest to assess seam integrity.[227]

PG&E spiked the pressure on multiple lines in 2003-2010 in order to maintain a five-year MAOP without having to hydrotest pipelines in compliance with Part 192.917.[228] PG&E's intent in performing the pressure spiking was to avoid any possibility that a future pressure increase would trigger the need to consider a manufacturing threat as unstable. The CPSD Report explains that PG&E should have considered the manufacturing threats on Segments 180 and 181 to be unstable due to any one of the following independent reasons: the occurrence of the pressure spikes after classification of the pipeline as an HCA pipeline, the information concerning Consolidated Western pipe welds contained in various records and reports, the fact that the spike test exceeded the pipeline MAOP, and the fact that PG&E did not conduct a cyclic fatigue analysis.[229]

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[225] There is insufficient data on the record to determine the date of installation of these pipelines, and thus whether the mileage overlaps with mileage PG&E should be responsible for due to other errors or omissions.

[226] 49 CFR 917(e)(3). TURN sometimes refers to such pressure increases as a "pressure excursion," though this is not a defined technical term.

[227] NTSB Report, pp. 37, 112; CPSD Report, p. 40, 42-49.

[228] CPSD Report, pp. 40, 44-49; NTSB Report, pp. 36-38, 112-113.

[229] CPSD Report, p. 44-49.

The CPSD Report concludes that PG&E should have hydrotested Segment 181 due to the pressure spiking in December of 2003.[230] This analysis likely applies to other pipelines. PG&E should have hydrotested, as part of integrity management work, the pipelines with identified manufacturing threats that it spiked in order to maintain a high five-year MAOP.

At a minimum, the Commission should find that PG&E is responsible for the work on those pipelines that it spiked that are now included in the PSEP. TURN has not been able to determine if the relevant data quantifying this issue are on the record in this proceeding. If not, PG&E should be ordered to produce the data. As a point of reference, TURN has submitted testimony in I.12-01-007 calculating that PG&E spiked approximately 415.3 miles of pipeline in 2003-2010.[231] Of this total, approximately 86 miles were included in the 2009 BAP as having a manufacturing threat. And of these 86 miles of spiked pipeline with manufacturing threats, 51.7 miles are included in the PSEP Phase I for testing (31.9 miles) or replacement (19.8 miles).[232]

Based on these numbers, P&GE shareholders would thus be responsible for about $16 million in expenses and about $89 million in capital costs.[233]

6.2.3 Pipeline Modernization Costs Should Be Disallowed for Any Defective Pipeline Segments that Should Not Have Gone Into Service

The NTSB Report found that Segment 180 was defective at the time of installation and that, with adequate quality control, PG&E would have detected the defect. This inadequate quality control "led to the installation and commissioning of a defective pipe that remained

[230] CPSD Report, p. 46-47.
[231] These data were provided to the NTSB and are likely on the relevant NTSB and the CPUC websites.
[232] The remaining 34.3 miles are included in the PSEP Phase II.
[233] These amounts are a subset of the larger disallowance recommended above for imprudently relying on ECDA for integrity management.

undetected until the accident 54 years later."[234] Given the NTSB's other findings that PG&E's numerous deficiencies reflected a "systemic problem,"[235] there is every reason to believe that PG&E imprudently allowed other defective pipe to be placed into service. Under prudence principles, ratepayers may not be required to pay to test or replace pipe segments that should never have gone into service.[236]

Unfortunately, we will likely not know which pipeline segments were defective upon installation until pipeline is excavated for hydrotesting or replacement. In Section 8.5 below, TURN recommends that the Commission require the presence of qualified independent inspectors at pipeline excavations; such inspectors can determine whether there were defects that should have been known at the time of installation.

Accordingly, until the Pipeline Modernization program is concluded, it will not be possible to determine a disallowance amount for this element of PG&E's imprudence.

6.2.4 PG&E's Termination of Its Gas Pipeline Replacement Program Is Further Evidence of PG&E's Imprudence and Yet Another Reason to Disallow PSEP Pipeline Replacement Costs

PG&E's termination of its Gas Pipeline Replacement Program ("GRPR") is another example of PG&E imprudence. GPRP was a safety-driven program that PG&E abandoned due to the corporate focus on cost cutting in 2000-2010. It is quite likely that PG&E's PSEP is now proposing to replace some of the very same 160 miles of pipeline PG&E had slated to replace in 2000-2010, but which it failed to replace after implementing its new Risk Management Program. PG&E's early termination of GRPR, contrary to its repeated justifications of the GPRP as necessary for safety, warrants making PG&E shareholders responsible for the costs of pipeline

[234] NTSB Report, p. 96.
[235] NTSB Report, p. 118.
[236] Ex. 121 (TURN Op. Test./Long), p. 5.

replacement. Alternatively, the Commission should consider the history of the GPRP early termination in calculating an ROE reduction for PSEP pipeline replacement capital costs.

In 1985, PG&E implemented a 25-year "GRPR" to replace about 2,467 miles of aging transmission and distribution lines, including approximately 500 miles of transmission line.[237] It appears that PG&E had intended to replace Lines 101, 109 and 132 as part of the GPRP.[238]

In its first rate case request to fund the program, PG&E indicated that "the replacement of these lines will enhance the safety and reliability of the gas piping system and will reduce leak repair expenses as high-maintenance piping is eliminated."[239] The Safety Branch staff at the time recommended the replacements be accelerated to a 15-year program. But PG&E did not believe it was feasible to accelerate, primarily due to the need to coordinate trenching with parallel water and sewer replacement programs for the City and County of San Francisco.[240] The Commission approved a 20-year program, with the expectation that there would be close monitoring by the Safety Branch.

While the exact scope and cost of the program was modified somewhat throughout the fifteen years 1985-2000, primarily in response to evolving risk assessment and risk modeling, the general intent to replace approximately 500 miles of older transmission line remained.[241]

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[237] Exh. 1, p. 2-12:18-24, Hogenson, PG&E.
[238] Exh. 45, p. 18:4-14, Felts Report in I.11-02-016.
[239] See, D.86-12-095, 23 CPUC 2d 149, 198-199 (1986).
[240] *Id.* At 199. It is likely that the trenching issue was more relevant to the distribution portion of the GPRP, which was the bigger component of the program.
[241] D.86-12-095 ordered PG&E to submit annual GPRP progress reports. These reports detail the evolution of the work scope and costs, and are available on the CPUC website at http://www.cpuc.ca.gov/PUC/events/110208_docs.htm The first Report describes the scope of transmission replacement as follows: "Replacement of steel transmission lines with pipe joint configurations and girth welds that do not meet current standards." GPRP 1987 Annual Report, March 31, 1988, p. B-1.

In the 1993 GRC, the Commission authorized full funding for the GPRP, despite evidence that forecast costs were higher than actual for the first six years, due to the importance of this program for pipeline safety:

> On this program we must agree with PG&E as to both the importance and necessity of moving forward with the gas pipeline replacement program as quickly as possible. The 1989 Loma Prieta earthquake certainly showed us the importance of PG&E replacing its old pipes throughout the City of San Francisco. … By authorizing the dollars PG&E requests for all of the accounts that deal with the gas pipeline replacement program, it is our fervent hope that PG&E actually spends the money on this program. We agree that this program is an important element of seismic safety improvement and urge PG&E to exercise due diligence in not only keeping the program on its targeted time line, but where feasible speeding up the program.[242]

In the 1996 GRC, TURN recommended a $35 million penalty due to consistent underspending on the GPRP and failure to "keep this important safety program on track." [243] The Commission agreed that for the first decade PG&E consistently underspent its authorized funds, primarily due to workforce reductions. While the Commission did not adopt TURN's proposed penalty, it did reduce the amounts authorized for the GPRP from PG&E's forecast, and emphasized the need for PG&E to complete the scheduled work:

> Between the time we issued the last general rate case decision and the filing of this one, PG&E has fallen short of our stated expectations. Over a three-year period, it spent nearly $28 million less than it received in rates for program expenses and $56.2 million less than it received in rates for the program's capital costs.
>
> PG&E supports higher funding levels in 1996 because it states its intent to replace pipe in high-cost neighborhoods. PG&E made the same argument three years ago. We adopted its requested funding assuming that PG&E would undertake that work. If it has not, we are not inclined to require ratepayers to pay for the work a second time.
>
> …

[242] D.92-12-057, 47 CPUC 2d 143, 233-234. Admittedly, the focus in the 1993 GRC was on the distribution component of the GPRP; however, because this was a unique program that included distribution and transmission, as well as capital and expense, the Commission apparently did not distinguish in rate cases between distribution and transmission replacement when authorizing the program.

[243] D.95-12-055, 63 CPUC 2d 570, 606.

> Notwithstanding PG&E's underspending of budgeted funds in this program in every year since 1985, PG&E has kept the program on target: after 40% of the program's timeline has elapsed, PG&E has completed 39% of the program. Apparently, we have funded this program at levels that are higher than required to fulfill program goals. With this in mind, we believe PG&E should be able to continue its targeted level of construction with less funding. … **However, if at the end of any year, PG&E has failed to meet targeted goals, we will consider imposing penalties on PG&E, consistent with TURN's recommendation, for compromising the safety of its gas distribution system.**[244]

In its 1999 rate case, PG&E proposed continued capital spending of $33 million for 1998-1999 on transmission replacement.[245] The Commission found that by 1997 approximately 57% of the planned transmission pipeline had been replaced,[246] and that PG&E had replaced transmission pipe at an annual rate of 24.1 miles in 1985-1998. The Commission also found that PG&E needed to replace transmission pipe at an annual rate of 20.1 miles for the remainder of the program to complete the planned work.[247]

In its direct testimony in this proceeding, PG&E touted the work of its GRPR:

> PG&E continually refined the priority methodology, incorporating ongoing leak detection information, feedback from O&M personnel regarding leak repairs, and the knowledge and experience gained during the duration of the program. As a result of this continual improvement process, PG&E gained a broad understanding of the different risks posed to T&D pipeline, and recognized the need to develop a program to address those risks specific to transmission pipeline. Transmission pipe segments were removed from GPRP with the advent of the Risk Management Program in 1998.[248]

PG&E went on to discuss the risk management activities developed in the transition to the Risk Management Program. PG&E notes that in April 20, 2000, the CPUC Utilities Safety

[244] D.95-12-055, 63 CPUC 2d 570, 606 (emphasis added).
[245] D.00-02-046, FOF 106, *mimeo.* at 455.
[246] D.00-02-046, Sec. 8.3.4.2.1, *mimeo.* at 207.
[247] D.00-02-046 at 210, fn. 28.
[248] Exh. 1, p. 2-12:30 to 2-13:5, Hogenson, PG&E.

and Reliability Branch approved PG&E's Gas Transmission Management Program, and that as a result 212.3 miles of transmission main were removed from the GPRP and placed into the Risk Management Program.[249]

PG&E's recounting of what happened to the 212 miles remaining from the original 500 miles of transmission line in the GRPR ends with the 2000 transition to the Risk Management Program. What happened with this pipeline?

Apparently, not much. The data provided by PG&E indicate that rather than continuing with the forecast replacement of about 20 miles per year, PG&E's transmission replacements decreased dramatically to an average of 4.4 miles per year in 2000-2010,[250] resulting in a ten-year deficit of approximately 160 miles of pipeline replacements originally included in the GPRP.[251] This deficit is remarkably close to the 185 miles PG&E now proposes to replace.[252] The scheduled replacement of Lines 109 and 132 never happened as planned.[253]

Apparently, the pipeline work planned under the GPRP was replaced by a new risk management priority assessment under the Risk Management Program, which then morphed into the Transmission Integrity Management Program.[254] Eventually, PG&E focused on using direct assessment to comply with federal integrity management regulations. In the process the original

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[249] Exh. 1, p. 2-14:1-8, Hogenson, PG&E.
[250] Exh. 131, p. 80, Kuprewicz, TURN. See, also, Exh. 133, Attachment 2. TURN notes that based on PG&E data responses, we calculated an annual replacement of 18 miles per year in 1985-1999. The discrepancy between this number and the 24 miles per year discussed in D.00-02-046 is not explained on the record. PG&E did not address this issue in its rebuttal testimony, despite the lengthy explanation of GRPR in its direct testimony.
[251] Calculated approximately as: (20-4) fewer miles replaced per year * 10 years (2000-2009) = 160 miles.
[252] There is no specific data in this record detailing the extent of overlap between the pipeline originally planned for replacement in the GPRP, versus the pipeline scheduled for replacement in the PSEP.
[253] Exh. 45, p. 21:17 to 22:6, Felts Report in I.11-02-016.
[254] Exh. 1, p. 2-14 to 2-16, Hogenson, PG&E.

goals of the GPRP were sacrificed to cost cutting considerations. The Overland Report quotes internal PG&E documents touting the cost cutting benefits of the RMP:

> Avoided $6 million in capital GPRP in 1999 (over previous years spending), sustainable in future years. Over the life of originally planned GPRP program (to 2009), will yield a total of $60 million dollars in savings.
>
> Presenting Risk Management Program to CPUC in May to gain approval to replace the GPRP program with Risk Management Program. Targeting an additional $3 million savings in GPRP ….[255]

The Overland Report concludes that "PG&E replaced the transmission portion of the GPRP with the RMP in 2000. The RMP was viewed internally as a cost reduction measure."[256]

PG&E has characterized its cost responsibility Principle 2 as warranting shareholder payment for work that PG&E was "obligated to pursue" even if D.11-06-017 had not been issued. Although pipeline replacement under the GPRP was not mandated by any specific regulations, PG&E's past representations to the Commission show that the program was needed to meet PG&E's obligations under Sections 451, 463 and general prudence principles. PG&E consistently testified to this Commission that the program was required for safety and work efficiency in every rate cases from 1985 through 1999. The Commission consistently authorized expenditures, and consistently urged PG&E to continue the work.

PG&E's failure to complete the replacement of the additional 160 miles planned for replacement in the GPRP, including Lines 109 and 132, represents a failure by PG&E to do work it was obligated to pursue as a prudent operator. The reduction in pipeline replacement constitutes another example of how PG&E management prioritized cost cutting over safety investments in 2000-2010. Under PG&E's own principle, the Commission should hold PG&E

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255 Overland Audit Report, p. 7-1 to 7-2.
256 Overland Audit Report, p. 7-1.

shareholders responsible for the costs of replacing the 160 miles of pipeline that PG&E should have replaced previously, a capital cost of $720 million.

At a minimum, the Commission should take the history of the GPRP into account in determining the level of an appropriate disallowance or reduction in the return on equity for capital expenditures, as discussed in Section 7.1.

6.3 The MAOP Validation Project Is Needed to Remedy PG&E's Imprudence and Its Costs Should Be Disallowed In Full

The first part of PG&E's "Pipeline Records Integration Program" is what it calls its MAOP Validation Project.[257] PG&E states that the purpose of this project is to validate the MAOP of its transmission pipelines based on the pipeline features.[258]

PG&E has forecast expenses for MAOP Validation in 2011 through 2013 totaling $162.3 million.[259] Of that amount, PG&E shareholders will absorb: (1) $55.2 million in 2011 expenses; and (2) $47.4 million in 2012 and 2013 expenses for post-1970 MAOP validation.[260]

For the reasons explained below, the MAOP Validation Project is necessary to remedy PG&E's imprudence and its costs should be disallowed in full.

6.3.1 The MAOP Validation Project Is Needed to Address the Demonstrated Inaccuracy in PG&E's Pipeline Records

In D.11-06-017, the Commission explained that the genesis of the MAOP Validation Project was the very serious problem of PG&E's inaccurate records:

> . . . this project to validate MAOP was set in motion by the NTSB's justifiable alarm at PG&E's records being inconsistent with the actual pipeline

[257] The second part, the Gas Transmission Asset Management ("GTAM") project will be discussed in the next section.
[258] Ex. 2 (PG&E Op. Test.), p. 5-1.
[259] Ex. 2 (PG&E Op. Test.), p 5-13, Table 5-2.
[260] Ex. 2 (PG&E Op. Test.), p. 1-14, Table 1-1.

> found in the ground in Line 132. The pipeline features data for Line 132 were not missing; the recorded data were factually inaccurate. Records containing inaccurate pipeline features are fundamentally different from simply missing records. Curing PG&E's unreliable natural pipeline records was the obvious goal of the NTSB's recommendation to obtain 'traceable, verifiable, and complete' records and, with reliably accurate data, create a dependable MAOP.[261]

Thus, the Commission has already determined that the MAOP Validation Project is a response to the demonstrated inaccuracy of PG&E's records and the resulting need to "cure" these unreliable records.

In response to questions from ALJ Bushey, PG&E's record-keeping witness James Howe acknowledged that the "worst possible outcome" is to not know that a record is inaccurate and to rely upon it.[262] He agreed that with missing records, in comparison, the operator at least knows that there is a gap in information.[263]

Accurate records are vitally important to threat identification and risk assessment under the Integrity Management Program, as the NTSB explained in its Accident Report:

> The foundation of risk assessment is accurate information. The NTSB is concerned that the PG&E GIS still has a large percentage of assumed, unknown, or erroneous information for Line 132 and likely its other transmission pipelines as well. As stated earlier in this section, in many cases, accurate information could have easily been obtained during ECDA digs, but the information was not obtained or not entered. The lack of complete and accurate pipeline information in the GIS prevented PG&E's integrity management program from being effective.[264]

The NTSB thus pointed out that PG&E's problem of inaccurate records likely extends to other transmission pipelines beyond Line 132 and that it needs to be fixed. Tragically, because of inaccurate records, PG&E's Integrity Management Program was ineffective.

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[261] D.11-06-017, p. 17 (emphasis added).
[262] Tr., vol. 10, p. 1218: 6-9 (Howe/PG&E).
[263] Tr., vol. 10, p. 1218: 10-12 (Howe/PG&E).
[264] NTSB Accident Report, p. 110 (emphasis added). The preceding two pages of the report, pp. 108-109, document and explain these conclusions and warrant the Commission's full attention.

Given the evident serious dangers posed by continuing uncertainty about the accuracy of PG&E's records, the Commission, implementing the NTSB recommendation, took the necessary step of ordering PG&E to gather all its records of pipeline features and to make sure that all of those records are "traceable, verifiable, and complete" – in other words, accurate and reliable. Thus, although this project has the ancillary purpose of serving to validate MAOP, in PG&E's case, its direct and urgent purpose is to ensure that inaccurate records do not contribute to another disaster.[265]

For this reason, the MAOP Validation Project is clearly remedial in nature, and all costs of this project should be disallowed from rate recovery.

6.3.2 The MAOP Validation Project Remedies Other PG&E Record-Keeping Deficiencies That PG&E Should Not Have Allowed to Happen

The MAOP Validation Project also remedies other deficiencies in PG&E's pipeline records. Even though the retention of specific pipeline features data has not always been required by detailed regulations, maintaining an accurate and reliable record of key pipeline features is, and has always been, necessary for the safe transport of natural gas through those pipelines, for a variety of reasons. In D.11-06-017, the Commission cited the testimony of PG&E's Vice President for Gas Engineering and Operations that accurate pipeline features information is a necessary prerequisite to avoid "unintended consequences" when conducting hydrotests.[266] In response to questions from the ALJ, PG&E's witness Howe recognized that

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[265] As PG&E's witness acknowledged in response to the ALJ, notwithstanding the name of the program, the information that is being developed will not actually be used to establish MAOP. Tr., vol. 13, pp. 1756:18-1757:7.
[266] D.11-06-017, pp. 8,18.

"good engineering practice" is to make and retain as-built drawings of pipelines.[267] Mr. Howe also agreed that quality information about "the inventory and characteristics" of the pipeline is key to a well-run risk management system.[268]

Having a basic understanding of pipeline features was and is also important to setting a safe MAOP. Particularly for pipeline installed pre-1970 for which PG&E set MAOP by reference to historical operating pressure from 1965 to 1970, a prudent operator needed to have a basic understanding of pipeline features to provide a reality check on the historical operating pressure. As Mr. Howe explained, even under the federal regulations enacted in 1970 -- which established the minimum safety standards (i.e., not the higher prudence standards) -- an operator considering using the grandfathering method was required to reduce MAOP below the five-year historic operating pressure if the operator had other information to determine that a lower pressure was appropriate.[269] Thus, the regulations presumed that the operator would consult its other records to serve an important validation function. Such a validation exercise would have been particularly important for PG&E in light of the alarming fact that up to 70 percent of its pre-1970 grandfathered MAOPs were not even based on actual pressure readings but rather on post-hoc affidavits from pipeline technicians.[270] Under these circumstances, PG&E should have exercised particular vigilance to ensure that affidavit-based historic operating pressures were consistent with PG&E's records about pipeline characteristics and other operating history.

[267] Tr., vol. 10, p. 1216: 14-17.
[268] Tr., vol. 10, p. 1170: 14-22.
[269] Tr., vol. 10, pp. 1219:18-1220:13 (Howe/PG&E) (referencing 49 C.F.R. Section 192.619(a)(1)(4)).
[270] Tr., vol. 13, p. 1714:1-13 (Singh/PG&E). In contrast, Mr. Howe testified that he expected most operators to need to resort to affidavits less than 10% of the time. Tr., vol.10, p. 1222:14-1223:8 (Howe/PG&E).

In sum, the MAOP validation work PG&E is now doing to develop accurate and accessible information about its pipeline features is record-keeping work that PG&E should have done all along to meet the prudence standard for a pipeline operator transporting a hazardous gas. This is another reason why ratepayers should not be required to pay for any costs of this remedial project, work that D.11-06-017 accurately describes as "remedial document management."[271]

6.3.3 The Expert Assessment of PG&E's Record-Keeping Practices Prepared by PwC Confirms the Long-Standing PG&E Deficiencies That Need to Be Fixed

At hearing, Mr. Stavropoulos testified that the final version of a report regarding PG&E's record-keeping practices by outside consultants from PwC (formerly PriceWaterhouse Coopers) would be available soon. Shortly after the close of hearings, PG&E provided the report to TURN as a supplemental data request response.[272] By showing the serious record-keeping problems that persist at PG&E, the PwC Report confirms the long-standing deficiencies that never should have been allowed to develop and that need to be fixed.

The PwC Report is a detailed assessment of records and information management ("RIM") for PG&E's gas operations. According to the Report, the assessment was initiated in response to IRP Report project and began on November 16, 2011 with information gathering ending in early February 2012.[273] Detailed findings are set forth throughout the Report; as summarized in the Executive Summary, they indicate inadequate attention paid to record-keeping, leading to records that are often incomplete, inaccurate, unreliable, and inaccessible. The verbatim findings are:

- There is little formal RIM Governance within Gas Operations

[271] D.11-06-017, p. 18.
[272] [Proposed] Ex. 155 (TURN Cross Exhibit), DR Response TURN 29-1 supplemental.
[273] [Proposed] Ex. 155 (TURN Cross Exhibit, Final PwC Report) p. 6.

- Information is often incomplete, unreliable, and not fully traceable
- Clearly defined RIM procedures and quality controls are lacking within key work processes
- Employees have challenges easily and efficiently identifying and accessing key records for their work
- There is a lack of clear standards, work procedures, and training for how staff should create, manage, transfer, store, and dispose of records and information
- Existing processes are very manual, heavily paper-based, and may differ between office locations
- There are numerous and disparate technology applications and systems where data is stored in parallel to paper-based records. Both paper and electronic populations contain gaps and errors
- Information is not managed throughout its lifecycle; nor is it managed as a corporate asset[274]

These serious problems echo and confirm the major deficiencies identified in the IRP and NTSB Reports.[275] The fact that PwC found the same type of records mismanagement over a year after the San Bruno explosion underscores that PG&E needs to do extensive remedial work to enable its pipeline records and information management systems to meet the requirements of a prudent pipeline operator. The MAOP Validation project and, as discussed below, the GTAM project, are part of that remedial effort.

[274] [Proposed] Ex. 155 (TURN Cross Exhibit, Final PwC Report) p. 8.
[275] NTSB Report, pp. 108-110; IRP Report, p. 62.

6.3.4 PG&E's Claim That the MAOP Validation Project Is Needed to Meet a New 'Traceable, Verifiable and Complete' Standard Is Without Merit

PG&E contends that it is not performing MAOP validation to compensate for past record-keeping deficiencies, but rather to comply with new "traceable, verifiable and complete" requirements imposed by the NTSB.[276] This argument is wholly without merit.

First, PG&E's argument ignores the Commission's finding in D.11-06-017, discussed above, that the MAOP Validation Project arises from the uncertainty regarding the accuracy of PG&E's records. PG&E's failure to maintain accurate records regarding Line 132 was, to say the least, a "deficiency." The fact that a main purpose of the project is to rectify this failure and the resulting doubts about all of PG&E's records is reason enough to reject PG&E's claim.

Moreover, PG&E's argument, once again, ignores the difference between specific regulatory requirements and the prudence standard. As discussed previously, even if PG&E was not required to accurately document its key pipeline features under the minimum requirements of specific regulations, its obligations under Section 451, 463 and general prudence principles required PG&E to maintain this basic information in order to ensure the safe operation of its pipelines. PG&E's witness Mr. Howe acknowledged that prudent management of a gas pipeline system may require more than just following specific regulations.[277] He further recognized that, even if regulations do not require retaining particular records, the operator needs to make its own decision as to what records are needed to operate the system safely.[278] Notwithstanding this recognition, Mr. Howe's opinion that the Commission has imposed a new record-keeping

[276] Ex. 21 (PG&E Rebuttal), pp. 11-3 to 11-4.
[277] Tr., vol. 10, p. 1119:7-11 (Howe/PG&E).
[278] Tr., vol. 10, pp. 1141:28-1142:25 (Howe/PG&E).

requirement was formed without consideration of prudence principles; he conceded that his testimony does not "deal[] with prudency."[279]

When the prudence obligation is considered, PG&E's contention that "traceable, verifiable and complete" imposes a new standard cannot be sustained. To meet its burden of proof, PG&E must show that, heretofore, it was not obliged to maintain its records to be traceable, verifiable and complete. This is an argument PG&E cannot credibly make. Traceable, verifiable, and complete are adjectives that give content to the overriding goal of accuracy. A record should not be viewed as accurate unless it is not the product of a record-keeping system that allows the operator to conclude with confidence that it knows the source of the record, the record's authenticity can be verified, and the record provides complete information that would not be contradicted if other missing information were known. This is Record-Keeping 101, not a new standard. As the PWC Report put it, pipeline information needs to be "managed as a corporate asset."[280]

Even Mr. Howe, PG&E's main advocate for the view that traceable, verifiable and complete imposes a new requirement, could not help but concede that these are basic standards that gas pipeline operators have always had to meet. In response to questions from the ALJ, he agreed that having traceable, verifiable and complete records "has always been very important."[281] He further agreed to the "general principle" that "as long as pipeline operators

[279] Tr., vol. 10, p. 1210:28-1211:7 (Howe/PG&E).
[280] [Proposed] Ex. 155 (TURN Cross Exhibit, Final PwC Report) p. 8.
[281] Tr., vol. 10, p. 1229:24-1230:3 (Howe/PG&E).

have been in existence," their record-keeping programs should have been constructed so the records "have a reasonable and suitable guarantee of authenticity and reliability."[282]

Mr. Howe placed great reliance on the 1970 grandfathering provision as supposed evidence of regulatory recognition of and acquiescence to record-keeping deficiencies among gas pipeline utilities.[283] However, as explained in Section 6.3.5, this position finds absolutely no support in DOT's explanation of its decision to allow the grandfathering provision. Rather, grandfathering was allowed to account for different historical hydrotesting standards. When given the opportunity on the witness stand to point to any passage in the DOT's explanation that supports his view, Mr. Howe could find nothing – a result that seemed to surprise and confound him.[284]

Finally, in the event that the Commission is nevertheless inclined to give any credit to Mr. Howe's testimony that traceable, verifiable and complete was not a previously applicable standard in the industry, it should consider two points about Mr. Howe. First, although he was presented as a record-keeping expert, Mr. Howe testified that he was not familiar with Generally Accepted Record-Keeping Principles ("GARP"), a source for key records and information management principles that PG&E's own PwC consultants applied in their review of PG&E's

[282] Tr., vol. 10, pp. 1192:19-1120:1 (Howe/PG&E). Mr. Howe went on to state that it would be unreasonable to expect perfection in record-keeping. TURN agrees that, even though gas pipeline operators need to be held to a high standard of prudence commensurate with the high risks of transporting natural gas, prudence does not require perfection. However, the NTSB Report and the IRP Report leave no doubt that PG&E's pre-San Bruno record-keeping was nowhere near perfection and closer to abysmal.

[283] Ex. 21 (PG&E Rebuttal), p. 10-9 (pre-1970 pipelines grandfathered "as acknowledgment that operators may not have construction, design and testing records sufficient to validate MAOP based upon the new standards").

[284] Ex. 52 (CCSF Cross Exhibit); Tr., vol. 10, p. 1197:17-24 (Howe/PG&E).

record-keeping program.[285] This is equivalent to a professed accounting expert testifying that she has never heard of Generally Accepted Accounting Principles ("GAAP"). Mr. Howe may be a fine engineer, but he is clearly not qualified to opine about standards that a prudent record-keeping program needed to meet.[286]

Second, Mr. Howe exhibited a strong pro-PG&E, pro-industry bias and should not be viewed as an independent expert. He is a former colleague of Mr. Stavropoulos, and the two continue to be friends.[287] In addition, shortly before Mr. Howe prepared his written testimony, he and his firm provided consulting services to PG&E's gas operations under a $120,000 contract.[288] Moreover, Mr. Howe seemed to be of the view that the gas pipeline operator perspective was determinative of whether "traceable, verifiable and complete" constituted a new requirement. To support his position, he cited exclusively to pleadings and papers from the American Gas Association ("AGA"), the Interstate Natural Gas Association of America ("INGAA"), and Sempra, all industry representatives.[289] In fact, Mr. Howe's only support for his patently incorrect assertion that the grandfathering provision was adopted because of a lack of historical records was an AGA paper, not the DOT decision.[290] At hearing, he had to be

[285] [Proposed] Ex. 155 (TURN Cross Exhibit, Final PwC Report), p. 14 (listing GARP as a source for records and information management principles); *see also* Ex. 46 (DRA Cross Exhibit, CPSD Report in I.11-02-016), p. 1-8 (stating that Report used GARP principles as the basis for assessing PG&E's record-keeping practices).
[286] Mr. Howe was clearly uncomfortable with the notion of being a "record-keeping expert." When asked if that label applied to him, he stated, "Yes, I guess." Tr., vol. 10, p. 1158:2-4 (Howe/PG&E).
[287] Tr., vol. 10, pp. 1137:12-1138:12 (Howe/PG&E).
[288] Tr., vol. 10, pp. 1136:11-1142:9 (Howe/PG&E); Ex. 47 (TURN Cross Exhibit).
[289] *See, e.g.,* Ex. 21 (PG&E Rebuttal/Howe), pp. 10-2 to 10-3.
[290] Ex. 21 (PG&E Rebuttal/Howe), pp. 7-17.

reminded that regulators may hold a different opinion from the industry.[291] For all these reasons, Mr. Howe should not be viewed as an independent expert on record-keeping standards.

6.3.5 The Grandfathering Provision Was Not Implemented as an Acknowledgement of Industry-Wide Lack of Records, but Rather to Account for the Fact that Historical Requirements for Strength Test Pressures Were More Lenient

PG&E claims that its lack of historical pressure test records for pipelines installed prior to 1970 reflect common industry practice. PG&E further maintains that the grandfathering provision of Part 192.619(c) was adopted specifically due to the general lack of historical pressure test records among gas operators. PG&E concludes that the PSEP is made necessary because this Commission decided to eliminate the grandfathering provision as an option for setting pipeline MAOP.

PG&E's "grandfathering defense" conflicts with historical evidence. Simply put, the original purpose of the grandfathering provision was *not* to excuse lack of records, *but* to account for different historical hydrotesting standards.

The industry standard for strength testing was first codified in B31.8 in 1935. The 1935 standards did not require post-installation pressure testing.[292] The 1942 version required post-installation pressure testing at pressure up to 1.5 times the maximum operating pressure within cities or villages, or up to 50 psi above the maximum operating pressure for other gas pipelines.[293] This "50 psi" requirement continued until adoption of the 1955 revision to B31.8,

[291] Tr., vol. 10, pp. 1168:14-1169:21 (Howe/PG&E).
[292] Exh. 143, Attach. A, p. 3, Pocta, DRA.
[293] *Id.* p. 5.

which adopted the more modern location classification with corresponding pressure test ratios ranging from 1.1 to 1.4 times the maximum operating pressure.[294]

The requirements adopted in the 1970 federal regulations extended on B31.8-1955 and required the strength test pressure to exceed the MAOP by a factor of 1.1, 1.25 or 1.5, depending on class location.[295] As an alternative to strength testing to the required pressure test levels, the regulations allowed an operator to set the MAOP based on the highest actual operating pressure during the five years 1965-1970. This is the so-called "grandfathering provision."

As discussed in Section 6.3.4 above, PG&E's primary outside witness on record-keeping maintains that "the problem of missing and incomplete records, including strength test pressure records, exists throughout the pipeline industry."[296] Mr. Howe opined that the grandfathering provision of 691(c) was adopted specifically due to the general lack of historical pressure test records among all gas operators.

The only evidence Mr. Howe presents for his explanation of the purpose of the grandfather clause is citations to industry statements made in 2011.[297] However, these *post-hoc* explanations conflict with the actual contemporaneous history of the federal regulations.

The original draft MAOP requirements proposed by the Department of Transportation did not include the grandfathering provision.[298] The text of the federal register from August 19, 1970 explains that the Federal Power Commission was concerned that the new regulations could cause pipeline operators to have to reduce pressure on thousands of miles of pipeline installed

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[294] *Id.* p. 11-12.
[295] 49 CFR 192.503(a)(1) and 192.619(a)(2)(ii).
[296] Exh. 21, p. 10-6, A7, Howe, PG&E.
[297] Exh. 21, p. 10-6 to 10-9, A7, Howe, PG&E.
[298] Exh. 52, 35 Federal Register 13248. The requirements for setting the MAOP and the grandfathering provision is the first substantive issue discussed in the federal register.

between 1935-1951.[299] The Department of Transportation recognized that since many pipelines "were tested to no more than 50 pounds above maximum allowable operating pressure, these proposed regulations would have required a reduction of operating pressures."[300] As a result, the DOT stated that "in view of the statements made by the Federal Power Commission, and the fact that this Department does not now have enough information to determine that existing operating pressures are unsafe, a 'grandfather' clause has been included in the final rule to permit continued operation of pipelines at the highest pressure to which the pipeline had been subjected during the 5 years preceding July 1, 1970."[301]

The extensive discussion from the Department of Transportation never mentions the lack of records as a rationale for implementing the grandfathering provision. Rather, it explains that the grandfathering provision allowed operators to maintain existing MAOP levels without retesting the pipelines to higher pressures. The grandfathering provision does not provide any evidence that the federal regulators condoned or even appreciated an industry-wide lack of pressure test or other pipeline records. PG&E's lack of test pressure records constitutes imprudence and is in no way excused by the existence of the grandfather clause in Part 192.619.

6.3.6 If the Commission Does Not Disallow All MAOP Validation Costs Now, It Should At Least Disallow Any MAOP Validation Costs for 1955-1969 Pipeline

The foregoing has shown that there are multiple reasons to disallow all MAOP Validation costs. If the Commission nevertheless decides not to do so at this time, the CPUC should at least

[299] For example, consider a high pressure transmission line with an MAOP of 400 psi. The '50 psi' test requirement means this line would have been tested to 450 psi. Depending on class location, the 1955 standards would have required testing to 440, 500 or 600 psi. Unless it were in a Class 1 location, the pipe would have to be retested. Similarly, any pipeline with an MAOP exceeding 500 psi would automatically have to be retested under modern strength test standards.
[300] Exh. 52, 35 Federal Register 13248.
[301] *Id.*

disallow all MAOP validation costs for pipeline installed from 1955-1969.[302] Beginning in 1961, GO 112 required PG&E to pressure test all pipeline before it went into service, and to retain records of those strength tests. Beginning in 1955, ASA B31.8 similarly called for pre-service strength testing and retention of test records. Because pressure test records are one way to establish MAOP,[303] PG&E should have already had the records to validate MAOP for all pipeline since ASA B31.8 was adopted in 1955. Accordingly, any costs PG&E needs to incur to validate 1955-1969 pipeline segments should be the responsibility of PG&E's shareholders.

6.4 PG&E Should Not Be Permitted to Recover in Rates Any Costs for GTAM

PG&E states that the GTAM project will "substantially enhance and improve" its record-keeping in several respects, including: "the amount and the types of information that PG&E collects and maintains electronically about its system; the business processes for collecting, validating, and retaining pipeline systems data; the traceability of materials used in the construction and maintenance of PG&E's gas pipelines . . .; and PG&E's ability to assess and mitigate potential public safety risks."[304] From 2012 through 2014, PG&E estimates that it will incur capital expenditures totaling $95.2 million and expenses in the amount of $20.5 million, for which it seeks rate recovery. For the reasons set forth below, the Commission should not allow any rate recovery for GTAM.

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302 PG&E concedes that its shareholders should be responsible for post-1970 MAOP validation costs. Ex. 21 (PG&E Rebuttal Testimony), pp. 1-11 to p. 1-12.
303 Tr., vol. 9, pp. 964:26-965:7
304 Ex. 2 (PG&E Open. Testimony), p. 5-2 (Overview of GTAM Project).

6.4.1 PG&E Has Failed to Satisfy Its Burden of Showing That GTAM Is Not Remedial In Nature

As explained in Sections 5.5 and 5.6 above, the Commission may not approve rate recovery for GTAM costs unless PG&E has demonstrated that GTAM is not needed to remedy PG&E's past imprudence. PG&E has failed to meet its burden, and, in any event, the Commission should await the completion of the record in the Record-Keeping OII (I.11-02-016) before reaching a conclusion that any portion of the GTAM is not remedial in nature.

The record to date already strongly suggests that much, if not all, of the GTAM is needed to remedy PG&E's serious record-keeping deficiencies. Even PG&E's own description, summarized above, of the ways in which PG&E's record-keeping program will be "improved" indicates a potential remedial purpose. For example, PG&E says that GTAM will improve PG&E's "business processes" regarding pipeline record-keeping. Those processes – including how old pipeline information is archived and new information is captured and how quality of data is assured -- have been roundly criticized as deficient by the Independent Panel Report,[305] the NTSB Report,[306] and the PG&E's own PwC Report,[307] as well as CPSD's testimony in I.11-02-016.[308] The findings of PG&E record-keeping problems in the IRP Report, NTSB Report, and the PwC Report are so deep-seated and sweeping that there is a strong likelihood that all of PG&E efforts to improve its records and information management are remedial in nature.

The hearing testimony of PG&E's GTAM witness supports this view. When presented with various findings of PG&E's record-keeping problems in the IRP and NTSB Reports, the

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[305] IRP Report, p. 62 (concluding that PG&E lacks robust data and document information management systems and processes).

[306] NTSB Report, pp. 108-110 (concluding that the lack of complete and accurate information in PG&E's GIS system prevented PG&E's integrity management program from being effective).

[307] [Proposed] Ex. 155 (TURN Cross Exhibit, Final PwC Report) p. 8.

[308] *See, e.g.,* Ex. 46 (CPSD Report), pp. 1-7 to 1-11 (concluding, "in lay terms", that PG&E's record-keeping "was in a mess and had been for years.")

witness confirmed that GTAM contained elements to address those problems. For example, regarding the IRP Report finding that PG&E lacked the necessary systems and processes to archive historical data and to capture emerging information, he testified that the MAOP project is building the component listing of pipeline as installed "and the GTAM project is really focused on maintaining that information on a going-forward basis to the traceable, verifiable and complete standard."[309] The witness continued:

> Q. So when the [IRP Report] says that there's a lack of robust data and document information management systems to archive historical data, is that something that's being addressed by either of the two programs that you are sponsoring?
>
> A. *As part of the GTAM project we do have a document management system that is being installed*, and that document management system will be part of the core systems. And so in order to maintain the traceable, verifiable and complete information, the characteristics of each of the components will be linked to essentially the source document that is located in the document management system.
>
> Q. And when the report says that there's a lack of processes to capture emerging information about the underground gas transmission system, is that an issue that either the MAOP Validation Project or the GTAM will address?
>
> A. *As part of the GTAM project we are remaking a lot of the business processes*. In order to collect that information to the traceable, verifiable and complete standard we are implementing the field collection of the data in electronic format. . . .[310]

In addition, when presented with the finding from the NTSB Report that "[t]here is no requirement to update pipeline records with data collected from the excavation and examination portions of the ECDA process,"[311] the witness stated that this issue is being addressed in GTAM by a new process called "electronic redlining of documentation" that will allow field personnel

[309] Tr., vol. 13, pp. 1696:4-1698:4 (Whelan/PG&E).
[310] Tr., vol. 13, pp. 1698:5-1699:4 (Whelan/PG&E) (emphasis added).
[311] NTSB Report, p. 109.

who observe something different from the records in the central databases to note the discrepancy to be validated by the mapping group."[312]

All of this testimony shows that the GTAM is fixing serious problems with PG&E's records management. It is ensuring that documented pipeline information remains traceable, verifiable, and complete; it is installing a document management system for archived historical information that will allow pipeline feature information to be traced to the source documentation; it will "remake business processes" to allow new information from the field to be incorporated into the master records; and it will create a process to allow field workers to recommend changes to the master records based on their observations. These are all fundamental functions and processes that were lacking in PG&E's pre-explosion records and information management system, to the extent it can be called a system at all. Ratepayers should not have to pay for PG&E to make these fundamental changes to remedy its serious deficiencies.

In response, PG&E reiterates its view that GTAM is designed to meet what PG&E claims is a new "traceable, verifiable and complete" standard.[313] For the reasons explained in Section 6.3.4 above, this is not a new standard; PG&E's prudence obligations under Section 451, 463 and general prudence principles required PG&E to meet this standard as long as it has been transporting natural gas. Therefore, this argument is not a reason to find that PG&E is entitled to rate recovery for GTAM costs.

If the Commission is not ready to disallow GTAM costs now, at a minimum the Commission must refrain from authorizing rate recovery of any GTAM costs at this time. In the Records-Keeping OII (I.11-02-016), the Commission will develop a full record on PG&E's past

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[312] Tr., vol. 13, pp. 1701:14-1702:8 (Whelan/PG&E).
[313] Tr., vol. 13, p. 1775:10-21 (Whelan/PG&E).

record-keeping practices. Until that record is complete, the Commission will not have all the information it needs to assess the extent to which the GTAM is remedial in nature and costs should be disallowed.[314]

6.4.2 The Commission Needs to Rigorously Audit the GTAM Work

Precisely because the GTAM project is addressing serious information management problems at PG&E, the Commission must rigorously audit the GTAM work to ensure that it is meeting all objectives.[315] To avoid allowing PG&E to have undue influence over the audit work and findings, the audit should be conducted (at PG&E's expense) by independent experts retained by either CPSD or the Energy Division.[316] Because of the demonstrated importance of records management to pipeline safety, the audit should be conducted regardless of whether any rate recovery for GTAM is authorized. In the event that, at a later point in this proceeding, the Commission approves rate recovery for any GTAM costs, the Commission should direct that no cost recovery be allowed until the audit finds that GTAM has met PG&E's recordkeeping needs.[317]

6.5 The Commission May Not Find That Any of PG&E's PSEP Costs Are Entitled to Rate Recovery Until the OIIs Are Resolved

During her questioning of TURN's witness Mr. Long, ALJ Bushey noted that the question of cost disallowances "has to be answered in fairly short order"[318] and encouraged TURN to be as detailed as possible in this brief regarding prudence-based disallowance

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[314] Ex. 121 (TURN Testimony/Long), pp. 15-16.
[315] Ex. 121 (TURN Testimony/Long), p. 16. PG&E's rebuttal testimony did not challenge or otherwise discuss TURN's recommendation.
[316] *Id.*
[317] *Id.*
[318] Tr., vol. 14, p. 2065:10-13.

arguments.[319] In response to the ALJ's direction, TURN has carefully analyzed the record and been as thorough and detailed as possible in this brief about the state of the record on prudence issues. Based on the record to date, TURN has demonstrated above that all of the PSEP costs are needed to remedy PG&E's past violations and imprudence and therefore should be disallowed from rate recovery. Alternatively, TURN has explained on an issue-by-issue basis why, at a minimum, substantial costs in the PSEP should be disallowed.

However, as TURN explained in its testimony, the current record is far from complete on the full scope of PG&E's imprudence and the extent to which the PSEP is needed to remedy such imprudence.[320] The three pipeline safety OIIs – I.11-02-016 (record-keeping), I.12-01-007 (San Bruno investigation) and I.11-11-009 (classification) – will examine PG&E's past pipeline management practices in much more depth and are sure to demonstrate many more ways that the PSEP and its constituent elements are remedial in nature. As contemplated in the OIR opening this docket, the Commission should take official notice in this proceeding of the record in those other dockets.[321] Until the record in those dockets is closed, TURN and other parties will not have had an opportunity to present their full case concerning the relationship of PG&E's past practices to the work and costs proposed in the PSEP.[322]

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319 Tr., vol. 14, p. 2074:17-2075:6.
320 Ex. 121 (TURN Testimony/Long), pp. 8-9.
321 In the OIR opening this docket, the Commission recognized the relevance of the record in "other proceedings," including I.11-02-016 (the only OII that had been opened at that time) to the ratemaking determinations in this case and expressly contemplated taking official notice of the records developed in those other dockets. R.11-02-019, pp. 11-12, fn. 6.
322 Mr. Long's testimony pointed out that even the three OIIs, as currently scoped, will not address the full scope of PG&E's violations and imprudence with respect to its Integrity Management Program and its installation of defective pipe and that the Commission needs to expand its investigative efforts. Ex. 121 (TURN Testimony/Long), pp. 8-9.

In addition, TURN notes that CPSD's Report in the San Bruno Investigation (I.12-01-007) seeks 41 remedies for alleged PG&E violations, several of which appear to overlap with PSEP work for which PG&E seeks ratepayer funding.[323] Such remedies for violations would be funded by shareholders. The requested remedies include: revising PG&E processes and procedures for data gathering and data verification (Recommendations ## 2, 5); ensuring PG&E's GIS database has all relevant leak history records (#6); recognizing manufacturing and construction threats as unstable due to PG&E's pressure-spiking practices (#8); using $39 million in unspent money for previously funded work to offset PSEP expenses (#31); using $95 million in unspent money for previously funded capital expenditures to offset PSEP capital costs (#32); and using $430 million in revenue collected above PG&E's authorized ROE to offset rate recovery for PSEP (#33). Commission approval of these, or other, proposed remedies in I.12-01-007 could significantly reduce any eligible PSEP cost recovery for PG&E.

For these reasons, based on the record to date, it would be premature – indeed legal error given the mandatory requirement of § 463 – for the Commission to make a final determination that any of PG&E's PSEP costs would be appropriate for rate recovery. Before final rate recovery for any PSEP costs can be allowed, at least two steps must happen: (1) the evidentiary record in each of the three OIIs has closed and parties in this docket have had an opportunity to present updated testimony and arguments about prudence and any other cost responsibility issues in a separate phase of this proceeding; and (2) in the OIIs, the Commission has determined the remedial measures that shareholders are required to fund and parties in this case have had an

[323] CPSD, Incident Investigation Report, I.12-01-007, released January 12, 2012, pp. 164-171. This Report is incorporated by reference in Ex. 121 (Long/TURN) at page 4. TURN notes that CPSD has not yet presented such a detailed list of recommendations in I.11-02-016 and has not yet presented its report in I.11-09-009, and that additional remedial measures that could affect PSEP rate recovery could be proposed in either of those dockets.

opportunity to provide argument about the impact of those adopted measures on the scope and cost of PSEP work. As TURN noted in both its written and oral testimony, in considering the record and outcomes of the OIIs, the Commission needs to be mindful of the different legal standards in the OIIs and this case.[324] In the OIIs, the Commission must determine whether PG&E committed violations of applicable legal requirements and, if so, what penalties and other remedies are appropriate. In this case, the Commission must apply the prudence principles discussed in this brief, recognizing that conduct that may not rise to the level of a violation may nevertheless be imprudent.[325]

TURN recognizes – as exemplified by the ALJ's questions of TURN's witness Mr. Long[326]– that the Commission is eager to resolve the PSEP rate recovery issues as quickly as possible. TURN further realizes that the two steps set forth above may take the better part of a year or more to conclude. To attempt to expedite the process, Mr. Long suggested at hearing that the Commission could address step (1) before a final decision in the OIIs. However, since providing that oral testimony, TURN has realized that, as just discussed, any remedial measures ordered in the OIIs may reduce any eligible PSEP cost recovery. With that recognition in mind, TURN now believes it would be more efficient to hold a single second phase of this proceeding, in which parties could address both the step (1) and step (2) issues. Such a single second phase would need to await the resolution of the OIIs. However, if the Commission deems it necessary, such a schedule could be expedited by sequencing Steps (1) and (2) serially, so that Step (1)

[324] Ex. 122 (TURN Rebuttal Testimony/Long), p. 4; Tr., vol. 14, p. 2070:8-23.
[325] Ex. 122 (TURN Rebuttal Testimony/Long), pp. 3-4.
[326] Tr., vol. 14, p. 2065:1-17 (Long/TURN).

testimony and briefing would occur upon the close of the OII records (as Mr. Long suggested at hearing), and Step (2) briefing[327] would take place after the OIIs are decided.

In any event, the important point is that, until steps (1) and (2) are concluded, the Commission will not have a complete record on the prudence and other cost responsibility issues that must be resolved before making a final determination that any PSEP costs are entitled to recovery in rates.

If the Commission nevertheless determines that it should approve any interim rate increase for PG&E before steps (1) and (2) are concluded, such rate increase must be made subject to refund, and such an increase should include only a fraction of PG&E's forecast costs, so as to minimize unreasonable revenue overcollections.[328]

7 Apart From Disallowances for Imprudence, Other Ratemaking Adjustments Are Appropriate to Reduce the Ratepayer Share of PSEP Costs

The IRP Report found that PG&E's top management was overly focused on financial performance and corporate image and insufficiently attentive to public safety, and that this corporate culture contributed to the serious failings in PG&E's operation of its gas transmission system.[329] Similarly, the NTSB Report characterized the San Bruno explosion as an "organizational accident" that reflected a "systemic problem."[330] And the CPSD San Bruno Incident Investigation Report discusses numerous ways in which fiscal priorities (including improved financial performance through cost cutting and workforce reductions) and corporate

[327] At this point, TURN does not anticipate that testimony would be needed in Step (2), but TURN reserves the right to offer a different view once the Step (2) issues become clearer.
[328] Ex. 121 (TURN/Long), p. 9.
[329] IRP Report, p. 16-17, 48, 52-53.
[330] NTSB Report, p. 117-118.

image took priority over safety expenditures or investments during the general time frame 1995-2010.

The net results are documented in the Overland Consulting audit report, which found, among other things, that:

- PG&E's actual transmission O&M expenses were five percent lower ($43 million) than amounts authorized in 1997-2010;
- PG&E's actual transmission and storage capital expenditures were six percent lower ($94 million) than authorized in 1997-2010;
- PG&E's gas transmission and storage revenues exceeded authorized revenue requirements by $224 million in 1999-2010, and exceeded the amounts necessary to earn authorized returns by $430 million; and
- PG&E's gas transmission and storage revenues exceeded the amounts necessary to earn authorized returns by $430 million in 1999-2010, and PG&E's resulting actual return on equity averaged 300 basis points above authorized for the twelve-year period.[331]

During the same time period as it was reducing O&M costs and limiting capital spending, PG&E spent money to enrich shareholders and corporate executives. PG&E authorized cash dividends of $2.7 billion in 2005-2009, authorized a stock repurchased of $2.3 billion, and spent over $50 million per year in 2008-2010 in stock incentives for top executives and managers.[332]

This history warrants significant modifications to any future cost recovery, separate from any disallowances based on findings of imprudence or deferred maintenance. Simply put, PG&E

[331] Overland Report, pp. 1-1, and 5-1 to 5-3.
[332] CSPD Report, pp. 140-142.

shareholders should not earn healthy profits and its managers should not receive incentive bonuses, resulting from any of the work done under the PSEP. In order to accomplish a measure of equity due to continued historical focus on profits and cost cutting, the Commission should adopt the following modifications to any future cost recovery of actual costs:

- The Commission should reduce the return on equity on PSEP capital expenditures to the present cost of debt, or at minimum to the low end of the reasonable range of ROEs already authorized by the Commission (Section 7.1);
- The Commission should remove amounts for incentive compensation from overheads applied to PSEP costs (Section 7.2);
- The Commission should order PG&E to first use certain internal sources of funding before raising rates, including bonus funds from accelerated depreciation, overearnings in GT&S, and executive bonuses already included in rates (Section 7.4).

Additionally, TURN recommends that the Commission order PG&E to apply a longer 65-year depreciable life for transmission mains (Section 7.3). Such a change is warranted based on available data and will simply result in a longer amortization of cost recovery, leading to reduced short term rate impacts.

Finally, TURN proposes a mechanism to incorporate any present or future findings regarding deferred maintenance. TURN also shows that available evidence warrants a disallowance of $720 million in capital costs due to the unreasonable deferral of 160 miles of pipeline replacement originally scheduled as part of the Gas Pipeline Replacement Program, which was touted by PG&E as essential for safe service over the course of at least fifteen years.

Likewise, the available evidence warrants a disallowance of the $70 million (estimated) spent on ECDA during 2004-2010.

7.1 The Commission Should Authorize a Reduced Return on Equity on Actual Capital Spending

Given PG&E's history of executive bonuses and high profits on its gas operations during a time of cost cutting and lack of spending on pipeline maintenance, integrity management or line replacement, the Commission should not allow PG&E shareholders to profit from implementing a plan designed to achieve the system safety that the company long neglected. In the event that the Commission ultimately finds that PG&E has met its burden of justifying cost recovery of any PSEP capital expenditures, PG&E's rate of return on such expenditures should be limited to no more than PG&E's cost of debt, currently 6.05%.[333] This recommendation reduces the present value of revenue requirements over the life of the equipment by 26.0% due to reductions in return and taxes.

If the Commission does not reduce the rate of return to the cost of debt, TURN alternatively recommends that the Commission adopt as an upper bound ROE for PSEP capital additions an ROE that is at the low end of the range of reasonableness that the Commission already adopted in the last cost of capital proceeding. Such an ROE level appropriately balances the factors that the Commission considers in setting the ROE.

In the last cost of capital proceeding, the Commission found that "a fair and reasonable ROE range" for PG&E was "from 10.30% to 11.50%."[334] The Commission authorized an ROE

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[333] See, Exh. 121, p. 16-17, Long, TURN; and Exh. 98, p. 9, Marcus, TURN.
[334] D.07-12-049, Sec. 5.6.2, p. 40. Please note that in his testimony Mr. Marcus inadvertently referred to 10.2% as the low end, based on the range specified for SCE.

of 11.35% for PG&E by adopting a rate of return "at the upper end of an ROE range found to be just and reasonable."[335]

Within the range of reasonableness, the Commission can consider issues of management effectiveness and efficiency when setting the ROE. The very need for PG&E to spend as much as $10 billion on gas pipeline safety to make up for problems that developed over decades suggests that management has not been effective or efficient in this important area. As a result, spending to correct the safety problem should not be rewarded with a rate of return "at the upper end of an ROE range found to be just and reasonable." The Commission should authorize for PSEP capital investments a return that in no circumstances exceeds the minimum reasonable return previously authorized by the Commission.

Reducing the ROE from 11.35% to 10.3% would reduce the revenue requirements over the life of the project by somewhat less than 5.65%.[336] When setting a maximum ROE in this way, in future cost of capital cases, the Commisison should continue to set the ROE for PSEP plant 105 basis points below the authorized ROE, unless the Commission finds a different relationship between the low end of the range of reasonableness and the authorized ROE.

PG&E and CCUE raise various arguments against an ROE reduction. None of these arguments are persuasive.

PG&E relied heavily on the testimony of Dr. Susan Tierney, an outside consultant who PG&E retained to rebut proposals for ROE reductions from TURN, DRA and Northern California Indicated Producers ("NCIP"). Dr. Tierney's rebuttal presented five ratemaking

[335] Exh. 98, p. 10, Marcus, TURN. See, also, Exh. 143, p. 19-20, Pocta, DRA.
[336] Mr. Marcus's calculations were based on a reduction to 10.2%. PG&E's RO model in the end will provide the proper reduction.

principles that the Commission should apply in this case.[337] She then showed that her principles supported PG&E's proposal for minimal shareholder responsibility for PSEP costs with no ROE reduction and that intervenors' proposals for ROE reduction violated her principles.[338]

A key problem with Dr. Tierney's analysis was that her assignment for PG&E did not include any review of PG&E's past practices or conduct with respect to pipeline safety.[339] She conceded that the extent of PG&E's mismanagement of its gas pipeline system was irrelevant to her analysis.[340] As a result, while her principles may make sense in an ordinary ratemaking setting, they fail to offer useful guidance to the Commission here where the utility has mismanaged its gas transmission pipelines on a grand scale for a long time. For example, one of Dr. Tierney's principles – that rates should fully reflect the costs of providing the service – does not account for the possibility that, under established prudence principles, PG&E should not be allowed to recover costs that are the result of its imprudence.[341] Similarly, Dr. Tierney would not agree to a basic principle that even PG&E seems to accept – that regulators should not make customers pay to remedy a utility's mistakes.[342]

In addition, her principles betray an evident bias toward minimizing the adverse financial impact of this proceeding on PG&E. Such a bias is understandable given her position on the Board of Directors of EnerNOC (she is Chair of the Nomination and Governance Committee), a demand-side management services company that receives substantial revenue from PG&E: $3.9

[337] Ex. 21 (PG&E Rebuttal/Tierney), pp. 2-7 to 2-11.
[338] Ex. 21 (PG&E Rebuttal/Tierney), pp. 2-11 to 2-30.
[339] Tr., vol. 9, p. 1019:23-27 (Tierney/PG&E).
[340] Tr., vol. 9, p. 1022:19-26 (Tierney/PG&E).
[341] Tr., vol. 9, pp. 1027: 4-1028:3 (Tierney/PG&E).
[342] Tr. vol. 9, pp. 1029:26-1030:11 (Tierney/PG&E).

million in 2009, $4.6 million in 2010, and $7.4 million in 2010.[343] In light of PG&E's status as a significant customer and EnerNOC's recent financial difficulties, one can surmise that Dr. Tierney would not be well-received in the EnerNOC Board room if her testimony in this case were to have any adverse financial effect on an important utility customer such as PG&E.

Dr. Tierney and CCUE's witness argued that a reduced ROE would be much worse than penalties or disallowances because it would reduce incentives for investment in safety improvements.[344] This argument overlooks the fact that shareholders invest in the whole company, not in a particular capital program. Given that the PSEP is a small part of overall investment in PG&E's gas operations and the gas operations are smaller than PG&E electric operations,[345] the impact of an ROE reduction on PG&E Corporation's overall return to investors will be significantly diluted. In any event, given the breadth and depth of PG&E's mismanagement, it is entirely appropriate – indeed desirable from the standpoint of deterring future mismanagement -- for the financial consequences to be noticeable to Wall Street.

In addition, the claim that ROE reductions have a worse financial impact on the company than one-time penalties or disallowances makes no sense from a financial perspective.[346] The present value impact of a prescribed ROE reduction applied to PSEP rate

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[343] Tr., vol. 9, pp. 1011:14-28, 1013:19-1014:17 (Tierney/PG&E). As an EnerNOC Board member, Dr. Tierney received 12,000 shares of stock in 2010 and 2011 and continues to receives 4,000 additional share for each year of service. (*Id.*, pp. 1014:27-1016:9). EnerNOC's stock price has tumbled in the last year in part because a recent FERC ruling that will significant diminish the company's future sales opportunities. (*Id.*, pp. 1016:14-1018:28).
[344] Ex. 21 (PG&E Rebuttal/Tierney), pp. 2-13 to 2-14 (Q&A 20).
[345] For example, the 2011 revenue requirements for GT&S are approximately $500 million, as compared to the 2011 revenue requirements for all other operations (all electric functions plus gas distribution) of over $6,000 million. Compare, D.11-04-031 with D.11-05-018.
[346] Notwithstanding Dr. Tierney's testimony, Mr. Bottorff testified that penalties would have a much worse financial impact on PG&E than either disallowances or an ROR reduction. Tr., vol. 9, pp. 955:3-957:28 (Bottorff/PG&E).

base can easily be calculated and thus made comparable to a one-time disallowance. In her written and oral testimony, Dr. Tierney did not and could not provide any studies supporting the counterintuitive notion that sophisticated investors view differently a one-time disallowance and an ROE reduction of the same present value. Contrary to the suggestion of Dr. Tierney, a focused ROE reduction predicated on PG&E's mismanagement and misplaced priorities would not send a general message about the CPUC's regulatory approach, but rather a pointed -- and appropriate -- message about PG&E's deep-seated failures that led to the San Bruno disaster.

Finally, arguments that ROE reductions or significant disallowances would create the wrong incentives for pipeline safety ignore history. In response to questions from ALJ Bushey, Mr. Bottorff acknowledged that, for the past 30 years, the Commission has generally authorized full cost recovery and full capital return.[347] Whatever incentives may have been created by such regulation were demonstrably insufficient to prevent PG&E from emphasizing profits over safety. Clearly, the Commission needs to try something different to get PG&E's attention. Disallowances and ROE reductions would serve an important deterrent function by sending a strong message that PG&E must not only comply with the letter of particular regulatory requirements, it must also exercise its independent judgment to take all steps necessary to operate its facilities in a safe and prudent manner.[348]

7.2 Incentive Compensation Should be Removed From PSEP

Ratepayer funding of performance incentives associated with PSEP costs would be a classic case of adding insult to injury. If, contrary to TURN's showing, PG&E is allowed any significant rate recovery for PSEP, those rates should not be augmented by bonus payments.

[347] Tr., vol. 9, pp. 959:25-960:20 (Bottorff/PG&E).
[348] Ex. 122 (TURN Rebuttal/Long), p. 4.

TURN therefore recommends that costs for the Short-Term Incentive Program included in standard labor and corporate overheads should be removed from PSEP capital expenditures, and costs for the Short-Term Incentive Program included in labor loaders should be removed from PSEP expenses. PG&E's company-wide forecast of capitalized short-term incentive bonuses for 2011 was $29,349,000,[349] but we do not know the precise impact on PSEP costs.

7.3 The Depreciable Life of Transmission Mains Should Be Increased to Better Align with Data on Useful Life and to Reduce Short Term Rate Impacts

TURN recommends that the Commission adopt a depreciable life of 65 years for PSEP pipeline replacements, rather than the 45 years PG&E currently uses for transmission mains. This recommendation does not impact cost recovery over the life of the plant, but reduces near term rate impacts. First year revenue requirements would be reduced by about 4.2%.[350]

PG&E responds that TURN has not performed a depreciation study, and that any such change should be made after considering a complete depreciation analysis in PG&E's next GT&S rate case.[351]

The Commission has enough evidence on the record to conclude that it is reasonable to create a separate subaccount for depreciation purposes solely for transmission mains installed as part of the PSEP program. The present depreciable life of 45 years was established in 1996 and

[349] Exh. 98, p. 8-9, Marcus, TURN.
[350] Exh. 98, p. 10-11, Marcus, TURN. PG&E corrected the depreciation numbers used by Mr. Marcus, so revenue requirement impacts would be slightly less than TURN calculated. See, Exh. 21, p. 17-10, A.19, Marre, PG&E.
[351] Exh. 21, p. 17-10, Marre, PG&E.

has not been reviewed since then.[352] PG&E's own data show that 68% of its transmission main is older than 40 years, and 47% is older than 50 years.[353]

SoCalGas proposed an increase in the service life of its transmission main from 55 to 57 years in its current rate case, while TURN proposed a 65-year depreciable life.[354]

Even though TURN prefers keeping old pipe when doing so is consistent with safety, new steel pipe manufacturing methods are improved[355] and should increase the useful life of steel transmission pipe. Likewise, improved compliance with requirements to strength test all new pipelines should better exclude defective new pipe from installation (at least as compared to the period pre-1970). These changes should increase the useful life of new pipe, especially as compared to older vintage pipe that is part of the basis for the 45-year life. TURN believes that it is entirely reasonable to adopt a much higher service life for depreciation purposes for the new pipeline that will be installed under the PSEP.

7.4 Certain Internal Sources of Funding Should be Used Before Ratepayer Funds to Finance PSEP Costs

Long-term equity between shareholders and ratepayers warrants the use of certain internal funds for the PSEP work before any ratepayer funds are used.

TURN has identified three internal PG&E sources of funding for gas safety work. In the event that a balancing account or memorandum account is adopted and regardless of what specific costs the Commission allows or disallows for recovery, the first dollars of revenue requirement for gas safety work should come from: (1) Resolution L-411 (deferred income taxes from 2011-12 bonus depreciation), (2) an earnings review that would identify any earnings in

352 Exh. 98, p. 10, Marcus, TURN.
353 Exh. 1, p. 2-4, using data from Table 2-2.
354 Exh. 98, p. 10, Marcus, TURN.
355 15 RT 2159, Kuprewicz, TURN.

excess of the authorized rate of return for Gas Transmission and Storage programs and use them for safety program funding; and (3) $23.5 million per year from shareholders, which effectively shifts the currently allowed ratepayer funding of executive and top manager bonuses throughout PG&E as a whole (and included in rates in other parts of PG&E's operations today) to gas pipeline safety.[356]

7.4.1 Bonus Depreciation Funds As Authorized in Resolution L-411 and L-411A

Resolution L-411A requires PG&E to track the revenue requirement impacts of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which provided for 100% bonus depreciation from September 9, 2010 through the end of 2011 and 50% bonus depreciation in 2012. The memorandum account tracks the revenue requirement going forward from April 14, 2011. PG&E can use the funds in this memorandum account to pay for pipeline safety work, consistent with the specific intent of the Resolution:

> For gas utilities, projects would include accelerating existing programs of distribution pipeline replacement, replacement of the riskiest or highest priority gas transmissions based on reasonable engineering assessments, and installing "smart pig" and associated plant in gas transmission lines.[357]

Consistent with this resolution, PG&E can spend money arising from deferred taxes for gas plant for PSEP projects.[358] Before requesting funding through any balancing or memorandum account, PG&E should first use this source of funding, which has already been approved for this purpose and requires no further Commission action. Any remaining gas-related

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[356] The details supporting these recommendations are provided in Mr. Marcus's testimony. See, Exh. 98, pp. 3-7.
[357] Resolution L-411A, page 6.
[358] The resolution states that at least 90% of the incremental investment amount must be attributable to the tax benefits associated with the particular service function (gas or electric).

money in the memorandum account when the account is closed should be used to pay for additional gas safety investments instead of being returned to ratepayers.

In its rebuttal, PG&E claims that using these funds for the PSEP is "inappropriate," but then fails to provide any legal or factual basis for this claim. In fact, PG&E's main argument is that "those benefits are already spoken for" because PG&E spent "roughly $17 million in additional GT [gas transmission] capital investments."[359] This argument simply proves TURN's point that this is a useful source of funding for gas transmission work. PG&E should use any remaining and future revenues in the Tax Act Memorandum Account to fund PSEP projects prior to using ratepayer revenues.

PG&E also claims that the memorandum account cannot be used to offset spending already included in rates. TURN agrees. That is why the Commission should order PG&E to use the balance in the Tax Act Memorandum Account for funding the PSEP work first, prior to recording any ratepayer revenues as credits.

7.4.2 Potential Future Overearnings from Gas Transmission and Storage Operations

Every year, the Commission should subject the gas transmission and storage ("GT&S") operations of PG&E (aside from the gas safety funding in this case) to an earnings review. The earnings review will determine the rate of return for GT&S operations from actual revenue, expenses, and rate base, with a limited number of pro forma adjustments.

According to the Overland Audit, GT&S has earned an average of about 300 basis points more than its authorized return on equity from 1999 through 2010.[360] The earnings review will

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[359] Exh. 21, p. 18-2, Jones, PG&E.
[360] Overland consulting, *Focused Audit of Pacific Gas & Electric Gas Transmission Pipeline Safety-Related Expenditures for the Period 1996 to 2010*, December 30, 2011, page 1-3.

assure that PG&E shareholders are not earning more than the authorized return on GT&S operations while PG&E ratepayers pay money to fund massive safety programs. One of the first sources of funding for the safety programs should be any such overearnings at GT&S.

The earnings review would also include any reductions in rate base from larger amounts of accumulated deferred income taxes than forecast, capturing remaining benefits from the bonus depreciation rules in effect from 2009-2012.

For purposes of this earnings review, three technical adjustments should to be made to GT&S balancing accounts. These adjustments are detailed in Mr. Marcus's testimony.[361] Two adjustments are necessary to address mechanical timing differences arising from certain balancing accounts, and to ensure that PG&E meets its commitment to fund certain incentive bonuses and severance costs for departing corporate officers. The third adjustment would remove the costs of *all* incentive compensation, not merely the reduction associated with the GRC settlement, out of the GT&S revenue requirement, in recognition that PG&E paid incentive compensation at levels well above target for a decade, while neglecting safety of gas distribution and transmission systems. Mr. Marcus explains how excess earnings would be calculated and that a review process should be developed to review the resulting calculations.

PG&E objects to TURN's proposal as reopening an aspect of the Gas Accord Settlement V and thus "cherry-picking."[362] PG&E has no right to talk about cherry-picking. Fundamentally, DRA is absolutely correct that this whole PSEP is cherry-picking.[363] If PG&E wishes to abide by the terms of the Gas Accord V Settlement, or even normal rate case principles, it should absorb all the additional costs of the PSEP until the next rate case. What would be inappropriate and

[361] Exh. 98, p. 5-6, Marcus, TURN.
[362] Exh. 21, p. 17-6, Marre, PG&E.
[363] See, Exh. 143, p. 5-13, Pocta, DRA.

grossly unfair would be increasing rates to fund the PSEP while at the same time allowing PG&E to overearn the GT&S revenue requirement.

PG&E also notes that the Gas Accord V Settlement provided a one-way balancing account for integrity management expenses and adopted reporting requirements concerning project completion and costs.[364] These are both very positive elements of the Gas Accord Settlement, but are essentially irrelevant to TURN's recommendation. PG&E appears to be implying that the one-way balancing account for integrity management might reduce overearning. PG&E's argument is without merit. The integrity management expenses constitute about 4% of the GT&S revenue requirement.[365] PG&E's ability to overearn its authorized ROE for the GT&S business will depend more on cost cutting of other elements, as well as on higher than forecast revenues from the unregulated storage business.[366]

TURN does not have an estimate for this source of funding, though we note that PG&E's surplus revenues from GT&S averaged about $35 million per year for 1999-2010.[367]

7.4.3 Executive and Top Manager Bonuses

PG&E has paid out large bonuses over the last five years despite poor performance in a number of areas.[368] If ratepayers are facing billions of dollars of gas safety expenses, then shareholders should make a further contribution toward these costs by paying for top manager and executive bonuses at least until the next General Rate Case. Essentially, the money currently collected from ratepayers for these bonuses would remain in rates under the GRC settlement, but the shareholders would make an equivalent dollar payment that would be applied to gas safety.

[364] Exh. 21, p. 17-7, Marre, PG&E.
[365] Exh. 115.
[366] See, Overland Report, p. 5-5.
[367] Overland Report, p. 5-2.
[368] See, for example, CPSD San Bruno Incident Investigation Report, p. 142.

As explained by Mr. Marcus, this recommendation would result in a shareholder contribution of $23,436,000 per year of allowable revenue requirements remaining after the earnings review.[369]

PG&E argues that TURN's proposal selectively amends one of the issues decided in PG&E's last GRC. We believe the facts on the record warrant offsetting the amounts ratepayers pay for top executive and manager bonuses. This change to the GRC settlement is trivial as compared to the change to the GT&S Settlement effectively proposed by PG&E.

7.5 PSEP Cost Recovery Should Be Reduced for Deferred or Ineffective Maintenance

7.5.1 The Record Concerning Deferred Maintenance Is Incomplete, and the Commission Should Provide a Mechanism for Future Adjustments Based on Additional Evidence

Deferred maintenance involves several different types of actions by which the utility postpones necessary maintenance work, resulting in higher future costs to ratepayers. The Commission has historically penalized utilities, primarily through disallowances on capital spending or reductions in expense forecasts, for certain types of deferred maintenance. Deferred maintenance which results in unsafe conditions is also an example of imprudent action in violation of Sections 451 and 463.

There are various examples of deferred maintenance on the record in this proceeding. However, the deferrals of needed pipeline hydrotesting, in-line inspections and replacements easily span at least the past decade, if not longer. The focus of this proceeding to date has not been on a detailed review and quantification of those activities. It is thus difficult to quantify the impact of "deferred maintenance," separate and apart from the imprudent operations and record-keeping spanning several decades.

[369] Exh. 98, p. 7, Marcus, TURN.

Notwithstanding the limited record, below TURN recommends potential disallowances based on specific deferrals of pipeline replacements and in-line inspections. However, TURN emphasizes this is yet another area where the Commission must leave any cost recovery subject to future adjustment in a reasonableness review.

TURN's witness Marcus provided analytical recommendations on how the Commission could implement any findings relating to deferred maintenance (expense or capital) that might flow from this or other cases.[370] To the extent that a finding is made in this proceeding or other proceedings regarding deferred maintenance, a pool of money should be created that becomes an offset to ratepayer funding for the pipeline safety program (along with the earnings review and incentive bonus dollars). Deferred maintenance reductions should be implemented at an aggregate level (instead of being tied to specific projects) so that incentives are not created to choose to skip specific types of projects to avoid a disallowance or reduction.

Mr. Marcus further explained that, for pipeline integrity capital projects, dollars that PG&E did not spend in the past were essentially trued up in later rate cases. However, shareholders gained from the underspending for a period of time until costs were trued up. Thus the full amount of capital dollars does not offset current capital. Instead, if the Commission finds deferred capital maintenance in 2007 or prior years, a reduction of 30% from current capital spending should be made. This amount approximates carrying costs multiplied by an average of 2 years prior to true-up in the next case. If there were to be a finding of deferred capitalized maintenance from 2008-2010, the reduction should be 43%. Beyond the 30% received by shareholders prior to true-up, there should be a 13% additional reduction. By deferring capital spending until 2013 or later, PG&E would have permanently given up bonus depreciation that

[370] Exh. 98, p. 12-13, Marcus, TURN.

reduces the present value of capital-related revenue requirements by 13% of the deferred maintenance capital amount.

Finally, if the Commission wishes to match the deferred maintenance funding by shareholders with long-term revenue requirements, a portion of this money could be treated as a rate base offset (to offset return and income taxes on new capital projects) amortized back to ratepayers (to offset depreciation on new capital projects) over a significant period of time (e.g., 20 years).

7.5.2 The Record Shows Evidence of Long-Term Cost Cutting, but Is Inconclusive Regarding "Double-Dipping"

Mr. Marcus explained that one type of deferred maintenance is where the utility collects revenues for pipeline safety projects but fails to perform the work. The utility should not recover this money a second time. This amounts to double-dipping, which the Commission has consistently denied.[371] Instead, PG&E should be required to provide shareholder funding for its program equal to the previous funding.

The Overland Report provides indirect evidence of this type of deferred maintenance. For the period 1997-2010, PG&E's overall actual transmission expenses were 5% lower than adopted revenue requirements, with a total deficit of $39,257,000.[372] PG&E's actual capital expenditures were 5.6% lower than forecasts used to set the revenue requirements, with a total

[371] See, for example, D.00-02-046, Conclusion of Law 15, p. 536 ("It would be unjust and unreasonable to make ratepayers responsible for expenses directly attributable to deficient or unreasonably deferred maintenance, or to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past."); D.04-07-022, Sec. 4.3.3, *mimeo.* at 98-99.

[372] Overland Report, p. 3-3, Table 3-2. The average annual level of underspending was $2.8 million.

deficit of $95,372,000.[373] On their own, these aggregate numbers do not distinguish whether PG&E deferred work included in rates, or accomplished the work at lower costs than forecast.

The Overland Report also found that a significant number of projects were delayed or cancelled. Out of a total of 65 projects included in the 2004 test year forecast for completion by the end of 2010, 18 projects related to integrity management or risk management were cancelled or delayed by over six months.[374] Six risk management projects were cancelled for financial reasons or due to reductions in risk scores. However, during the same time period of 2003-2010 PG&E actually overspent on capital projects related to reliability and integrity management.[375] The implication is that PG&E deferred capital work partly due to higher than forecast costs.

On the expense side, the Overland Report documents how during 2008, 2009 and 2010 the GT&S organization was under increasing pressures to cut expenses for integrity management.[376] The Overland Report describes considerable internal correspondence putting pressure on staff to reduce integrity management spending, as exemplified in the following conclusions concerning 2008 budgets:

> PG&E reduced 2008 Integrity Management expenses in two basic ways. It changed the assessment method for some projects from ILI to ECDA and it deferred some projects from 2008 to 2009.
>
> According to the 2008 Gas Transmission Program Review, "low funding drove many pigging projects to be changed to ECDA projects." Gas Engineering strongly preferred to smart pig PG&E's higher stress pipelines but doing so "was not financially viable at current funding rates." The documentation clearly indicates that resources constraints were the driving force behind the changes in assessment methods and project deferrals.[377]

Overland makes similar findings for 2009 and 2010. Indeed, in 2010:

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[373] Overland Report, p. 4-2, Table 4-1.
[374] Overland Report, p. 4-4.
[375] Overland Report, p. 4-3, Table 4-2.
[376] Overland Report, chapters 7 (for 2008), 8 (for 2009) and 9 (for 2010).
[377] Overland Report, p. 7-12.

PG&E adopted an initiative to change Integrity Management assessment methods from ILI to ECDA. That initiative created "headroom" in 2011 and 2012 to allow PG&E to defer integrity management projects from 2010 to those years. The assessment method changes and project deferrals were clearly driven by resource constraints.[378]

Thus, the record in this proceeding to date suggests that some PSEP costs constitute double dipping but does not allow us to make conclusive recommendations concerning deferred maintenance and double dipping.

7.5.3 The Commission Should Disallow the Historical Costs of ECDA, Which Represents a Waste of Ratepayer Money on Ineffective Inspection Work

Mr. Marcus explained that a second type of deferred maintenance results when the utility performs work using ineffective methods and has to redo the work using a different methodology. In such a case, the Commission should add the past costs of the ineffective work to the fund.[379]

The available evidence indicates that PG&E's expenses on ECDA may have constituted exactly this type of ineffective work, which must now be redone by performing testing or replacing on the same pipelines. Again, the data on the record here is limited. The Overland Report shows that PG&E spent $29,772,000 during 2008-2010 on ECDA.[380] The Commission could reasonably impute, based on an average of $10 million per year, total spending of $70 million for the period 2004-2010. This amount should be disallowed for deferred maintenance.

[378] Overland Report, p. 9-19.
[379] Exh. 98, p. 12-13, Marcus, TURN.
[380] Overland Audit Report, p. 3-5, Table 3-4.

7.5.4 The Unreasonable Deferral of Necessary Maintenance Work is Evidence of Imprudence and Separately Warrants a Disallowance

There is yet another type of deferred maintenance, based on the fact that not all dollars are earmarked for particular projects, and the utility has discretion in allocating funds to activities. Thus, deferred maintenance also includes an unreasonable deferral of needed maintenance work (even if the utility did not ask for the money for the work specifically), resulting in future costs that are higher than they should be. For example, the Commission reduced a test year cost forecast for facilities painting based on finding that the cost was excessive and resulted from years of neglecting to perform such painting:

> More to the point, SCE has not satisfactorily explained what events have occurred requiring the expenditure of an additional 12% each year to operate and maintain the hydro system. For example, SCE has not adequately explained why it did not paint certain hydro facilities for more than 20 years but must do so during the ratemaking test period.[381]
>
> We would expect a system most of whose components are 50 to 100 years old to have relatively high maintenance costs. However, during the recorded period from 1996 to 2000 the system was already old. SCE has not explained to our satisfaction why its test period maintenance costs should be so much higher than those of the same system were when those components were 45 to 95 years old. The fact that SCE did not apply paint for 20 years suggests inappropriate deferred maintenance as a possible answer.[382]

The record available in this proceeding provides compelling evidence of the deferral of needed work. The evidence indicates that PG&E's abrupt reduction in pipe replacement in 2000, PG&E's decision to entirely eliminate hydrotesting as an assessment alternative, and PG&E's limited use of ILI (and repeated reductions in planned ILI in favor of cheaper DA) for integrity management could all be construed as examples of deferred maintenance. These actions may

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[381] SCE's rebuttal testimony regarding the difficulty of painting penstocks does not overcome our concerns, nor does its rebuttal testimony regarding maintenance painting at Big Creek.

[382] D.04-07-022, Sec. 3.5.2, *mimeo.* at 74.

also have violated safety regulations, and would certainly be imprudent if they contributed to an unsafe system.

Quantifying the financial impact of this deferred maintenance is difficult, and was not the focus of this proceeding. However, the evidence indicates that if PG&E had continued its promised GPRP it would have orderly replaced an additional 160 miles of pipeline, including Line 132, during 2000-2009. Ratepayers would have paid the cost of that replacement over the past ten years. We do not know for certain whether costs would have been less than under the PSEP, though NCIP witness Beach provides one method of calculating the potential cost increase as a result of compressing the work into a three-year period.[383] More importantly, if PG&E had continued performing planned replacements, including those on Line 132, perhaps we could have avoided a tragic catastrophe and the need to test or replace some significant portion of PG&E's 6000 miles of transmission lines.

These are areas where additional evidence from the OIIs may be useful to evaluate whether PG&E unreasonably deferred necessary work.

If the Commission does not fully disallow PSEP costs based on prudence principles, then at a later point in this proceeding after the OII records have closed, parties should have an opportunity to make the case for cost disallowances for the three types of deferred maintenance discussed in this section.

[383] Exh. 123, p. 26, Beach, NCIP. TURN has not reviewed Mr. Beach's method and does not take a position at this time whether it is an appropriate quantification of deferred maintenance impacts.

8 Other Ratemaking Issues

8.1 If the Commission Does Not Disallow All PSEP Costs Now, A Memorandum Account May Be Appropriate

As explained in Section 6.5 above, if the Commission chooses not to disallow all PSEP costs now, then it should not make any final determination of whether any PSEP costs are entitled to rate recovery until the three enforcement proceedings are resolved. In this case and in the event the Commission does not approve DRA's separate proposal to postpone any cost recovery until the next rate case, then TURN would not be opposed to approving a memorandum account for PG&E. The memorandum account would allow PG&E to track for potential future cost recovery any non-disallowed PSEP costs it incurs after the date of the decision.

8.2 The Commission Should Reject PG&E's Proposal to Preclude a Future Reasonableness Review

PG&E asks the Commission to authorize revenue requirements going forward based on a forecast of expenses and actual capital costs of in-service projects. In addition, PG&E requests a balancing account, so that forecast and actual costs would be trued-up in the future. However, PG&E asks the Commission to find that any actual costs up to the forecast amounts are reasonable, so there would be no subsequent reasonableness review as long as costs are less than forecast.

The Commission should reject PG&E's proposal to preclude a future reasonableness review. TURN's witness Mr. Marcus gave two specific reasons why it would be inappropriate to forego a future reasonableness review. First, Mr. Marcus raised the possibility that, given the massive scale of PG&E's PSEP and the fact that the Sempra utilities may be implementing a similar large scale program at the same time, such a sudden crush of pipeline work in California could raise unit costs significantly.[384] Were such a price escalation to occur, it should be examined in a reasonableness review where TURN would be likely to contend that some increment of the unit cost increase should be borne by shareholders because the increase would have been avoidable had work been done over time rather than through a large crash program.[385] Second, there is a significant potential for cost-reducing technology that could reduce the need for both hydrotests and replacements. Mr. Marcus gave the example of the TIGRE robotic platform for inspection of unpiggable pipelines between 20-26 inches in diameter, an emerging technology discussed by Sempra in its pending rate case. Retaining the prospect of a reasonableness review would encourage PG&E to use this or other new technologies that reduce testing and replacement costs.[386]

8.3 If the Commission Authorizes the Use of Forecasts Costs, It Should Significantly Modify PG&E's Forecast Due to Inappropriate Inclusion of AFUDC and Due to Likely Reductions in the Scope of Work

PG&E seeks to collect revenues based on forecast expenses and actual capital-related costs, with annual true-ups to actual.[387] There is a significant likelihood that PG&E's cost forecasts are excessive. While TURN appreciates that annual true-ups minimize overearning on a long-term basis, PG&E would still get the benefit of the time value of money over the course of the year. The Commission should take steps to prevent this result. The best way is not to authorize any cost recovery prior to a reasonableness review, or alternatively to authorize cost recovery only based on actual costs.[388]

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[384] Ex. 75 (TURN/Marcus), pp. 14-15.
[385] *Id.*
[386] *Id.*, pp. 15-16 and Attachment 6.
[387] Exh. 1, p. 8-7, Marre, PG&E. See, also, Exh. 21, p. 1-25, Bottorff/Stavropoulos, PG&E.
[388] In other words, the Commission could adopt a balancing account that records actual costs versus revenues, with revenues amortized over some time period based on recorded costs.

However, if the Commission does allow any cost recovery based on forecast expenses, it should adopt the following modifications.

First, as discussed in Section 3.2 above, the scope of work for the pipeline modernization component will likely decrease when PG&E applies the results of the MAOP validation program to project engineering, due to the elimination of segments whose records might be found.[389] The forecast of the pipeline modernization program costs should be reduced by 33% to prevent unnecessary rate increases, followed by later refunds. The 33% reduction is based on the reduction in hydrotest mileage in 2011 due to MAOP validation. [390]

Second, as emphasized by the DRA,[391] PG&E's cost forecasts for both the pipeline modernization program and the valve automation program have a high degree of uncertainty and include an extremely large contingency. If the Commission authorizes any revenue requirement based on forecast costs, it should include only a portion – for example 50% - of PG&E's forecast costs.

Third, as detailed in Mr. Marcus's testimony,[392] PG&E's forecast of AFUDC for expenses must be eliminated and the forecast of AFUDC for capital must be reduced. PG&E has included AFUDC of 5.24% of all other costs in its estimates of overhead expenses for hydrotesting and 7.58% in its overhead estimates of capital projects.[393] These numbers are wrong. As Mr. Marcus explained, there is no AFUDC whatsoever on expensed projects. Thus

[389] Note that this is a separate impact from the issue of whether the proposed scope of work should be reduced based on a different prioritization (for example, eliminating much of the work in Class 2 locations).
[390] PG&E reduced the 152 miles of forecast hydrotest mileage in 2011 by 44.2 miles as a result of MAOP validation work. Exh. 131, p. 13-14, Kuprewicz, TURN.
[391] CITE
[392] Exh. 98, p. 11-12, Marcus, TURN.
[393] Exh. 98, p. 12, Marcus, TURN; and Exh. 99, Attachment 4.

all expenses for projects that are forecast using the PG&E estimating model must be reduced by about 5%.

Even for capital projects, the PG&E's AFUDC rate of 7.58% is too high, as it is the equivalent of assuming that the pipeline replacement project will take 10 months of financing *at its full cost* before it goes into service.[394] A typical project will have a period of engineering and design where a limited amount of money is spent and then will be built over a short period of time, be tested, and come into service. Mr. Marcus calculated that a more appropriate AFUDC rate for capital projects is 2.2%, resulting likewise in a 5% reduction in the average cost of all pipe replacement projects for forecasting purposes.[395]

PG&E did not rebut Mr. Marcus's analysis concerning AFUDC rates.

8.4 The Commission Cannot Allow PG&E to Defer Work Based on Cost Overruns, and Should Thus Reject PG&E's Proposal to Submit an Advice Letter for Additional Cost Recovery

In describing its proposed balancing account mechanism, PG&E at first implies that its cost forecast will be a cap on actual costs, so that "if PG&E spends more than the authorized amount, PG&E must seek Commission authorization to recover the difference in rates."[396] The implication is that PG&E will perform all the forecast work, and shareholders would absorb any cost overruns. That is precisely the point of the 20% contingency.

[394] *Id.* at 12, fn. 15. PG&E's data shows 8-50 direct crew-days for approximately 2 miles of work, depending on the size of the pipe and congestion.
[395] *Id.*
[396] Exh. 1, p. 8-1, Marre, PG&E.

However, what PG&E gives with one hand it taketh away with the other.[397] A few pages later, PG&E noted that "if circumstances lead to a change in the Phase 1 project scope, schedule or costs (e.g., changes in law, permitting processes by municipalities) that would cause the Phase 1 expenditures to exceed the approved forecast, PG&E would file a Tier 3 advice letter to request cost recovery of the amounts exceeding the approved forecast."[398] The implication of this statement is that cost overruns would be caused by some external event, not just an error in forecasting costs.

However, in its detailed explanation of the proposed Tier 3 advice letter, PG&E finally explains that the proposed 'cap' is no cap at all:

> However, if recorded costs are anticipated to exceed adopted forecast cost estimates, then PG&E may request recovery of additional costs through a Tier 3 advice letter. Should the Commission approve any increase in the forecast, the costs under the approved modified cost forecast shall be considered reasonable. Should the Commission not approve a request to modify the approved forecast, then PG&E would be authorized to modify the work scope to manage within the approved forecast.[399]

Mr. Marre agreed on the stand that this section means that PG&E would not carry out all the proposed work if there are cost overruns and its Tier 3 request for additional funding is rejected.[400] Moreover, Mr. Marre confirmed that this section is essentially seeking Commission authorization to modify the scope of work in the event the future advice letter is rejected.[401]

As explained by Mr. Beach for the Northern California Indicated Producers, PG&E's advice letter proposal:

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[397] In another example of such artifice, PG&E apparently hopes to take back any "PG&E shareholder responsibility" for PSEP costs as reductions to potential penalties in the enforcement proceedings. See, Exh. 21, p. 1-16, A 34, Bottorff/Stavropoulos, PG&E.
[398] Exh. 1, p. 8-7:4-11, Marre, PG&E.
[399] Exh. 1, p. 8-13:29 – 8-14:7, Marre, PG&E.
[400] 14 RT 1953:14-21, Marre, PG&E.
[401] 14 RT 1955:7-11, Marre, PG&E.

> Creates a significant loophole that compromises the value to ratepayers of the one-way balancing account protection and of Phase 1 cost controls. … Effectively, this places ratepayers at risk for Phase 1 cost overruns regardless of whether the Commission finds that such excess spending is reasonable.[402]

Moreover, as a procedural matter, the use of an Advice Letter to request a potentially unlimited amount of additional revenues due to cost increases is inappropriate. PG&E states that the advice letter "requires full review and approval by the Commission, and allows parties to protest and comment on any such request."[403] That is all true. However, commenting on an advice letter by filing one protest 20 days after submission of the advice letter is a far cry from protesting an application, having time to submit discovery requests, submitting expert testimony, potentially having hearings to explore contested material facts, and submitting briefs on factual, legal and policy issues. An Advice Letter is entirely inadequate to explore and contest the factual bases for a potentially large revenue request. And PG&E was unwilling to agree to an extension of the 20-day protest deadline or to commit to having evidentiary hearings on the advice letter request.[404]

The Commission should soundly reject PG&E's advice letter proposal if it adopts any variant of PG&E's cost recovery proposal.

8.5 The Commission Should Ensure Independent Inspection of Pipeline Excavations Conducted in the PSEP, and the Results Should be Incorporated into any Future Reasonableness Review of Actual Costs and Cost Responsibility

A complete record of evidence supporting a decision on shareholder responsibility for PSEP costs will not be available until after the records in the enforcement investigations are submitted. As explained in Section 6.2.3 above, if the Commission does not disallow all PSEP

[402] Exh. 123, p. 10, Beach, NCIP.
[403] Exh. 21, p. 17-20:27-29, Marre, PG&E.
[404] 14 RT 1956:3 – 1958:12, Marre, PG&E.

costs now, those records will need to be considered in a future phase as part of the evaluation of the prudence of PG&E's operations.

However, the impact of PG&E's past construction, testing, record-keeping and integrity management practices may not ever be fully known, given that the results of these practices are hidden in pipelines beneath the ground. The numerous excavations that PG&E will conduct as part of the PSEP testing and replacement work provide an important opportunity to collect key data concerning pipeline characteristics and potential defects. Significant useful information will be obtained from the actual physical inspection of pipelines exposed during the testing and replacement work.

For example, The NTSB Report reaches conclusions regarding the failure of Segment 180 from detailed physical inspection of the pipeline itself.[405] The CPSD Report concludes that *if* PG&E had strength tested Segment 181, it would likely have discovered that Segment 180 was a DSAW pipe, presumably as part of the physical inspection performed when excavating Segment 181 to perform hydrotesting.[406]

To ensure that relevant data concerning pipeline physical characteristics and conditions is properly collected and evaluated, TURN recommends that the Commission order the presence of qualified independent inspectors at excavations, require collection of vital information during excavations, and require independent corroboration of the results of a random sample of such data.

To this end, the Commission should require that PG&E hire, at shareholder expense, independent and qualified pipeline inspectors to be present to examine excavation sites to assess

[405] NTSB Report, Sec. 1.8, p. 39-50.
[406] CPSD Report, p. 47-48.

the condition of the pipeline. The presence of outside inspectors is vital not only to ensure unbiased inspection, but also because it appears that PG&E may not be properly capturing all relevant information during excavations.[407]

TURN recommends that independent inspectors be present for a random and statistically significant portion of the excavations. Additionally, for all excavations, the Commission should direct staff to develop a list of required data to be collected, including radiographic inspections of certain vintage welds. The Commission should direct independent experts to review the data collected from excavations.

The results of these inspections should be made public to parties in this proceeding, and should be incorporated in the Commission's ultimate determination of cost responsibility for PSEP work. Specifically, if the inspection results show that a particular pipe segment was defective at the time of installation, and that such a defect would have been found if prudently inspected during the time of construction or during integrity management, then the costs of replacing that particular segment should be paid by shareholders. Since this data will not be known until after completion of the pipeline modernization program, this review would need to be conducted after completion of the program.

9 Cost Allocation

9.1 PG&E's Allocation of Costs Based on the Methods Adopted in the Gas Accord Settlement is Appropriate for Most Pipeline Work

TURN has reviewed PG&E's proposed cost functionalization and allocation, which assigns safety-related costs to functions based on the type of pipeline being replaced or tested.

[407] The NTSB states the following concerning PG&E's ECDA procedure: "There is no requirement to update pipeline records with data collected from the excavation and examination portions of the ECDA process." NTSB Report, p. 109.

TURN generally agrees with PG&E that using the functionalization and allocation based on the type of pipe being addressed and the allocators adopted in the Gas Accord V settlement is appropriate, aside from one program element discussed below.

The Northern California Indicated Producers proposed an entirely new and novel cost allocation proposal that has no relationship to the type of work performed and is intended purely to shift costs to core (residential and small commercial) customers. TURN submitted rebuttal testimony, identified as Exhibit 100, explaining the basic fallacy of NCIP's proposal, which totally ignores fundamental cost allocation rules, that costs should be functionalized to the assets that cause the costs. TURN will address this issue in reply briefs if necessary.

9.2 However, the Gas Accord Cost Allocation Does not Apply to GTAM, Which Should Be Allocated Based on Total Pipeline Mileage

TURN's only concern concerning PG&E's cost allocation proposal relates to costs of information technology related to the Gas Transmission Asset Management (GTAM) project.[408] This program is designed to capture, validate, and retain large amounts of data related to all of PG&E's pipelines. PG&E appears to assign IT costs in proportion to the amount of work being done on the system – approximately 91.35% to local transmission, 8.65% to backbone and none to storage or customer-related service pipes.

The GTAM collects, validates, and stores data for all transmission pipelines on the PG&E system, not just segments being worked on under Phases 1 and 2 of the current program. Thus, it is inappropriate to use the mileage proposed in the PSEP Phase 1 as a proxy for cost allocation of the GTAM. Instead, TURN recommends that any GTAM costs allowed to be recovered in rates be assigned to functions by total miles of pipeline. It is the total pipipeline

[408] Mr. Marcus addresses this issue in Exh. 98, at pages 16-17.

mileage that is more directly related to the number of paper records generated over time that must now be collected, validated and stored as part of GTAM work.

TURN's recommended allocation used PG&E's mileage data to assign about 35% of the costs to backbone transmission and about 62% to local transmission.[409] PG&E confirmed these numbers,[410] and provided data showing the rate impacts of this recommendation, which are on the record in Exhibit 119. The net impact of the change between local and backbone rates is a reduction in revenue requirements (2012-2014) allocated to core customers of about $59.015 million.

10 Conclusion

For all the reasons set forth above, the Commission should adopt the recommendations contained in TURN's Summary of Recommendations.

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Respectfully submitted,

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[409] Exh. 98, p. 17, Marcus, TURN.
[410] Exh. 119, PG&E Response to TURN 020-01.