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August 20, 2012

Commissioner Michel Florio
California Public Utilities Commission
505 Van Ness Ave., 5th Floor
San Francisco, CA 94102

Re: R.11-02-019 - Phase 1 Pipeline Safety Enhancement Plan

Dear Commissioner Florio:

On June 16, 2012, TURN met with you to discuss their view of PG&E's Phase 1 Pipeline Safety Enhancement Plan (PSEP) as parties await a proposed decision (PD). If approved, our plan to test, verify and upgrade the integrity of our gas transmission pipelines will achieve the rigorous standards set by the CPUC and meet the highest standards of safety, reliability and affordability. Phase 1 of the plan makes significant progress to ensure and improve the infrastructure of over 1200 miles of pipe, automate 228 valves, and modernize our pipeline records.

I cannot stress enough how much TURN's views and ours diverge. While TURN's focus is decreasing scope and spending for new safety enhancements, our PSEP provides a comprehensive and aggressive plan to address safety. TURN also attempts to muddy clarity the Commission provided: the investigations will address past errors or omissions. PSEP is our forward-looking plan aimed at meeting new standards for pipeline safety and is not designed to focus on punishment or remediation.

We, like the Commission when it created this rulemaking, see PSEP as the critical path for new Commission regulations that go beyond existing federal regulations. This is why PG&E proposed strong cost protections for ratepayers ensuring they: (1) do not pay twice for the same work; and (2) do not pay for remedial work that should have been done in the absence of D.11-06-017. We respond in detail to TURN's materials in the attached document.

We urge you to maintain focus on the intent of this case, namely, to achieve a gas transmission pipeline system that is built and operated to the highest safety standards. Your approval of PSEP will launch a new safety-focused regulatory model that will ensure California leads the nation in safety.

Sincerely,

Brian K. Cherry
VP, Regulatory Relations

cc: President Michael Peevey
Commissioner Timothy Simon
Commissioner Catherine Sandoval
Commissioner Mark Ferron
ALJ Maribeth Bushey

Attachment

PG&E Response to TURN's Summary of Issues on PG&E's PSEP Proposal

TURN's June 26, 2012 Ex Parte Handout	PG&E Response
Why are we here?	

• San Bruno 9/9/10 explosion: 8 dead, 58 injured, 38 homes destroyed, another 70 homes damaged
• Key NTSB findings
• Key Independent Review Panel findings
• D. 11-06-017
  ○ MAOP validation project was set in motion by NTSB's "justifiable alarm" at PG&E's inaccurate pipeline records (p. 17)
  ○ Curing unreliable 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 (p. 17)
	• PG&E's Pipeline Safety Enhancement Plan (PSEP) is an unprecedented, multi-year program to implement new gas transmission safety regulations established by the Commission that are unparalleled in the United States. Phase 1 of the PSEP includes several complementary initiatives that are intended to meet the Commission's new gas safety regulations.
	• PG&E has accepted the recommendations in the NTSB and IRP reports and is working to implement them. The PSEP is not intended to cure all alleged deficiencies noted in the NTSB and IRP reports, but instead was developed to comply with the Commission's Decision Determining MAOP Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans (D. 11-06-017).
	• One of the four main components of PSEP is the Pipeline Records Integration Program, which consists of two work streams. The MAOP validation project will validate the MAOP of transmission pipelines based on the pipeline features and the GTAM will substantially upgrade gas transmission processes and record management infrastructure, allowing a transition away from reliance on traditional paper records and consolidating data into integrated, core data management systems.
	• D. 11-06-017 required all California gas operators to submit a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan to: (1) comply with the requirement that all in-service natural gas transmission pipelines in California that have not been previously pressure tested be strength tested or replaced; (2) complete the MAOP determination based on pipeline features; (3) include interim safety enhancement measures that will enhance public safety

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	during the implementation period; (4) consider retrofitting pipelines to allow for in-line inspection ("ILI") tools; and (5) consider the use of automated shut-off valves. • Prior to the NTSB recommendation and CPUC order, operators could set the MAOP through one of four methods, including the highest operating pressure in the 5 years preceding July 1, 1970.
Key issues in the case	
• How should the costs of the PSEP be apportioned between shareholders and ratepayers?	• PSEP puts forth cost-sharing principles that ensure that ratepayers (1) do not pay twice for the same work; and (2) do not pay for remedial work that should have been done in the absence of D.11-06-017.
○ To what extent is PSEP remedying PG&E's serious mismanagement of its pipeline records and overall transmission system (i.e., the result of PG&E's imprudence)	○ PSEP is not remedial and was developed to comply with D.11-06-017. Regulations in place prior to D.11-06-017 did not require PG&E to: (1) hydrotest pipelines that were installed prior to July 1, 1961; (2) validate the Maximum Allowable Operating Pressure ("MAOP") of all gas transmission pipelines through traceable, verifiable, and complete records; or (3) install automated shut-off valves. However, in instances where hydrotesting or other work must be done to comply with pre-existing regulations, PG&E has committed that such work will be ineligible for cost recovery in the PSEP.
○ In light of PG&E management's excessive focus on profits and insufficient attention to safety, what other ratemaking adjustments are appropriate (e.g., rate of return reductions, use of other sources of funding)	○ The Commission should ask: (1) what conduct is PG&E being punished for through adoption of an ROE reduction and has this conduct already been taken into account by other actions taken in the OIIs or in this proceeding? (2) How much will the ROE reduction cost PG&E, i.e., what is the equivalent disallowance? (3) If a disallowance is implemented through an ROE reduction, will there be an impact on the utility's ability to attract debt and capital and should the Commission care if there is an adverse impact?

	Furthermore, PG&E's ROE is set in the Cost of Capital proceeding at a level that allows a utility to compete successfully in capital markets to obtain the funds required to meet needed investment and provide a sufficiently sound financial footing for the company to maintain its credit quality and take on debt at a reasonable price. Introducing ROE reductions in this proceeding would interfere with the Cost of Capital proceeding, discourage investment in California utilities, increase market risk premiums, and ultimately impede the Commission's goal of implementing significant new gas safety enhancements in a manner that is as affordable to customers as possible. It is unreasonable and without justification to use other sources of funding to offset PSEP costs. Bonus depreciation, "overearnings" from past GT&S rates (1999-2012), and incentive compensation authorized in the last GRC were authorized by prior Commission ratemaking decisions and are completely unrelated to PSEP. PG&E has addressed alleged "overearnings" from past GT&S cases in its June 26 testimony in the San Bruno OII.
○ In light of the pending enforcement investigations that are likely to further illuminate the scope of PG&E's past management, when should the Commission make a final cost responsibility determination?	○ Cost responsibility should be determined now so that the important safety work can proceed expeditiously. In this proceeding, the Commission should address the scope of the work to be approved, the reasonable cost estimate for the approved scope of work, the customer/shareholder allocation principles that will determine which costs are eligible for cost recovery, and the ratemaking and rate design features necessary to implement new PSEP rates. Allegations raised in the

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	OIIs and their appropriate fines, penalties, remedial actions and disallowances will be addressed in those proceedings. After the OIIs are decided, PG&E should be directed to adjust its PSEP rates to reflect the decisions in the OIIs that affect the PSEP, if any.
• How should the proposed scope of the PSEP be modified to achieve the necessary safety improvements in the most cost effective manner?	• As proposed, PSEP achieves the necessary safety improvements in the most cost effective manner. PSEP's scope prioritizes the most urgent work, while also capturing cost efficiencies among projects. This balance ensures that customers benefit in the long term.
• Are PG&E's cost estimates reliable? (DRA)	• PG&E's cost estimates were supported by PG&E's extensive experience constructing and operating gas transmission pipelines in California, and the supporting data is detailed in volumes of work papers. DRA's cost estimates are based on inappropriate industry averages and cost estimates from a consultant whose industry experience is derived primarily from off-shore, sub-sea pipelines. DRA's estimates also assume a reduced work scope that may compromise safety and does not take advantage of efficiencies.
• What ratemaking accounting mechanisms (e.g., memorandum accounts, balancing accounts, after-the-fact reasonableness review) should be used to ensure that, for any of the costs apportioned to ratepayers, only reasonably incurred costs are recovered in rates?	• In order to ensure that only reasonably incurred costs for 2012 to 2014 PSEP are recovered in rates, PG&E proposes to establish a new Gas Pipeline Expense Balancing Account to track the difference between the Phase 1 forecast expenses and actual Phase 1 recorded expenses. If PG&E spends less than the amount authorized by the Commission, PG&E will refund the balance to customers at the end of Phase 1. If PG&E spends more than the authorized amount, PG&E must seek Commission authorization to recover the difference in rates through an advice letter filing. PG&E will also establish two new Gas Pipeline Safety Balancing Accounts; one for core gas customers and another for noncore gas customers, with separate subaccounts to track the adopted forecast expenses, actual capital-related revenue requirements, and actual

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• For any costs apportioned to ratepayers, what cost allocation methodology should be used?	revenue collected. Together the balancing accounts will provide a "true up" to ensure that PG&E will only recover in rates costs that are actually expended on the PSEP. • PSEP's cost allocation and rate proposal apportions transmission, local transmission, and storage revenue requirements between core and noncore customers consistent with the core and noncore revenue responsibilities established for each respective revenue requirement in the Gas Accord V Settlement.
Cost Responsibility Issues: What cost responsibility principles should the Commission use?	
• TURN: PU Code Sections 451, 463, and general prudence principles, the Commission must disallow costs resulting from PG&E's imprudence.	• TURN misconstrues the applicable requirements under the statutes. The Commission must conduct a reasonableness review of the proposed PSEP program and associated costs. However, there is no legal obligation to conduct a retroactive, historical prudence review of PG&E's past gas operations over the past 75 years to determine if the proposed PSEP rates are just and reasonable. • Section 451 is a general statute that requires rates for services to be just and reasonable and utilities to provide services as are necessary to promote the safety, health and convenience of its customers and the public. The statute does not state that any past utility act or omission found to be imprudent by the Commission violates section 451. Contrary to TURN's argument, there is no legal obligation under PU Code Section 463 for the Commission to conduct a duplicative reasonableness review of PG&E's past recordkeeping "errors and omissions" in the PSEP proceeding. This review is already taking place in the OIIs. This statute requires the Commission to review the prudence of utility actions that are related to the "planning, construction, and operation" of a capital asset over $50 million. This provision applies to documents necessary to evaluate cost overruns or delays in the development or construction of a capital projects

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	to be completed under the PSEP that are over $50 million. PG&E's historic gas pipeline pressure test records are not relevant to the management of potential PSEP cost overruns or construction delays for future pipe replacements. In addition, as specified in the last sentence of this section, this subdivision does not apply if a reasonable person could not have anticipated the relevance of the documents to an evaluation of the costs of the project over $50 million. There is no evidence to suggest that a reasonable person in the 1930's, 1940's, and 1950's could have anticipated that historic gas transmission pressure test documents would need to be developed and maintained (when there was no requirement to do so) because the documents might be relevant to the review of the construction of gas transmission pipelines in 2012 and beyond. PG&E has proposed that the Commission adopt an "estimate of the reasonable costs" of the PSEP pursuant to Section 463.5, which eliminates any legal requirement for the Commission to conduct an after the fact reasonable review of PSEP construction overruns or delays under Section 463.
• PG&E's "incremental" principle: If D.11-06-017 had never been issued, would PG&E have been obligated to do the work?	• D.11-06-017 establishes new regulatory gas transmission safety standards that were not in place prior to the issuance of the decision. The cost of complying with these standards is incremental to current gas rates.
○ Applied too narrowly by PG&E, which ignores Section 451 and prudence principles in assessing what it was "obligated" to do. (However, PG&E's SVP Bottorf acknowledged at hearing that its obligations for this purpose should include Section 451 requirements – PG&E retracted this position in its reply brief.)	○ Section 451 is a general statute that requires rates for services to be just and reasonable and utilities to provide services as are necessary to promote the safety, health and convenience of its customers and the public. The statute does not state that any utility act or omission found to be imprudent by the Commission violates section 451.
○ Federal regulations and GO 112 established minimum requirements; as the operator of pipelines transporting highly combustible gas, PG&E was entrusted with exercising its informed judgment to go	○ GO 112 established minimum pressure test requirements in 1961. In response to the CPSD Report on PSEP, PG&E has agreed with the recommendation that shareholders should pay for hydrotesting on post-

beyond those regulations as necessary to ensure safety of the system.
 	
• PG&E bears the burden of proof to demonstrate that PSEP costs are not the result of its imprudence.
• The Commission has made clear that fines and disallowances for the same behavior are appropriate – fines are paid to the general fund and do not mitigate the harm to ratepayers.
• Other principles:
  ○ Ratepayers should not be made to pay twice for the same work (deferred maintenance)
  ○ As a matter of basic fairness and in light of PG&E's past emphasis on profits over safety, the PSEP should not become a profit center for PG&E
	1961 pipelines where PG&E was missing documentation of pressure tests as required at the time under GO 112.
	• This is a misstatement of utility ratemaking principles.
	  ○ PSEP has two cost sharing principles: 1) Incremental costs associated with complying with the new regulatory gas transmission safety standard adopted by D.11-06-017 or as part of a new safety program proposed in response to that decision should be recovered in rates; 2) to the extent an activity must be undertaken in the PSEP to comply with preexisting regulatory requirements, PG&E will not seek cost recovery for such activities in the PSEP.

Application of Prudence Principles to PG&E's PSEP	

• A <u>full disallowance</u> is warranted: because the PSEP is the result of PG&E's imprudence – or, put another way, remedial in nature.
  ○ The NTSB's January 2011 urgent recommendations and the Commission's follow-on directives on D.11-06-017 were necessitated by PG&E's inaccurate pipeline records and the grave doubts created by those records about whether PG&E's MAOPs and its integrity management practices were reliable.
	• TURN's assertion that a full disallowance is warranted is based on the inaccurate assumption that the PSEP is intended to bring PG&E into compliance with pre-existing regulations. However, D.11-06-017 adopts significant new safety standards to modernize and establish a safety margin for every gas transmission pipeline.
	  ○ The new requirements are unparalleled and a clear departure from grandfathering of pre-1970 pipelines under current federal regulations. In D.11-06-017, the Commission ordered that every untested gas transmission pipeline must be pressure tested or replaced. Under the prior regulatory requirements, MAOP could be determined by methods other than pressure testing for pipelines installed prior to 1970 (under federal grandfathering regulations) or 1961

	(under GO 112). D.11-06-017 has eliminated the use of methods other than pressure testing for determining MAOP—this is clearly a significant change in regulatory requirements and not something PG&E or any other California gas utility was previously required to do as part of its historic operations. D.11-06-017 also ordered PG&E and the other California gas utilities to have "traceable, verifiable and complete records readily available" for all gas transmission pipelines (HCA and non-HCA) at the completion of the implementation period. This change in standard (for HCA pipelines) is also being considered on a national level. As described below, this entails far more than having a pressure test record for a gas pipeline and requires a massive MAOP validation project to gather existing documents, verify them and fill in any data gaps. In addition, PG&E will require a new data management system and process to complete this validation effort effectively and ensure that records are managed to the traceable, verifiable, and complete records readily available standard on a going forward basis. The PSEP work scope is designed to meet these new safety standards. Where work is required due to PG&E's failure to comply with past regulations, PG&E has agreed in its customer/shareholder allocation principle number 2 that such costs are ineligible for recovery in the PSEP.
○ The record shows that, if D.11-06-017 had not been issued, to remedy its pipeline system, PG&E would have moved ahead with its "Pipeline 2020" program, a program that is virtually identical to the Pipeline Modernization and Valve Automation programs proposed in the PSEP. ○ When asked at the hearing what steps PG&E would	○ Pipeline 2020 was developed by PG&E to raise the bar on safety requirements in California, not to comply with pre-existing regulatory requirements. It was intended to be submitted to the Commission in an application for its consideration and was contingent upon Commission approval and ratemaking authorization. Pipeline 2020 became the starting point

have taken if D.11-06-017 had never been issued, PG&E's Stavropoulos evaded the question, claiming PG&E had never given any thought to that question.
 	
Issue-by-issue disallowances supported by the incomplete record to date
• The costs of the MAOP validation project should be disallowed in full ($162 million expense)
  ○ As D.11-06-017 states, this project is the result of the NTSB's alarm at PG&E's incorrect records and the need to ensure that PG&E's MAOPs are based on accurate information
  ○ Contrary to PG&E's contention, the obligation to have "traceable, verifiable, and complete" records is not a new standard but rather a more precise articulation of the requirement to maintain accurate and reliable records
	for the PSEP after D.11-06-017 was issued.
	
	• Prior to January 3, 2011, federal regulations allowed operators to establish MAOP using any one of four possible methods. The January 3, 2011 NTSB recommendation and subsequent Commission order materially altered how an operator could establish the MAOP of its pipelines. Now, a strength test is the only permitted means to establish the MAOP of a pipeline. In addition, although the only permitted means for establishing MAOP is through strength testing, the Commission has nonetheless ordered PG&E to complete its MAOP Validation Project to validate the MAOP of its pipelines as an interim measure, until pipelines without a documented pressure test can be pressure tested or replaced. On May 7, 2012, the PHMSA issued an Advisory Bulletin (ADB-2012-06) informing gas operators of anticipated changes in annual reporting requirements to document the confirmation of MAOP. The PHMSA Advisory Bulletin includes a lengthy discussion of the terms "traceable," "verifiable," and "complete."

• Pipeline testing or replacement costs for pipeline installed from 1955 on should be disallowed ($241 million capital, $94 million expense)
  ○ Industry standards (later adopted by GO 112 and federal regulations) required pre-service pressure testing of all pipeline installed from 1955 on, and retention of test records for the life of the pipeline. PG&E helped formulate the 1955 standard and voluntarily followed the standard.
  ○ PG&E's failure to retain records of such pressure tests is imprudent and ratepayers should not be required to
	• When the Commission adopted GO 112 it did not apply the hydrotest requirements retroactively; the Commission expressly decided that the GO 112 hydrotest requirements to establish maximum allowable operating pressure would not apply to pipelines installed prior to 1961. Starting in 1955 the ASA guidelines recommended post-installation hydrotesting technical standards that are close to modern requirements and included requirements to retain documentation of such pressure test records. PG&E began to follow the guidelines on a voluntary basis in 1955. However, the ASA standards remained voluntary until 1961 when they were largely

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pay to remedy such imprudence
 	
• Pipeline testing or replacement costs for PSEP pipeline that PG&E improperly inspected under integrity management requirements should be disallowed ($89-$279 million capital, $16-$120 million expense)
  ○ PG&E used the wrong – and less costly – method (external corrosion direct assessment, instead of in-line inspection or pressure testing) to assess manufacturing threats
  ○ PG&E should have conducted a pressure test on segments with manufacturing threats where PG&E spiked the pressure
	incorporated in GO 112. There is no pre-existing legal or regulatory requirement to hydrotest pipelines installed from 1955 to 1960. The ASA standards were voluntary guidelines.
	• PG&E was transparent in filings to the Commission about how it intended to assess pipelines under TIMP. Direct assessment and ILI, two legally authorized assessment methods under Part 192 Subpart O regulations, were identified as the primary means of assessment in PG&E's TIMP Plan. PG&E clearly notified the Commission and parties of its TIMP implementation strategies and its rate authorization in the GT&S rate cases reflected the costs of implementing these approaches. The Commission approved PG&E's TIMP implementation strategies and funding request in the GT&S rate cases.
	• PG&E has identified some transmission pipelines that need to be hydrotested as part of TIMP. These hydrotests will not be eligible for cost recovery under the PSEP.

• Pipeline testing or replacement costs for PSEP pipeline that was negligently constructed or installed should be disallowed (unknown $ amount at this time)
  ○ NTSB found PG&E's inadequate quality control allowed defective Segment 180 to be installed.
  ○ It is likely that other PSEP pipeline was defective and should never have been installed. Ratepayers should not pay to remedy such imprudence.
  ○ The Commission should direct PG&E to have independent inspectors at excavation sites to assess whether pipe segments were defective.
	• There is no evidence to suggest that pipelines to be tested or replaced under the PSEP were negligently constructed or installed.

• The costs of the Gas Transmission Asset Management (GTAM) project should be disallowed in full ($95 million capital, $21 million expense) ○ The record shows that the GTAM is needed to remedy PG&E's serious record-keeping deficiencies, as identified by the outside PwC report commissioned by	• In addition to the MAOP Validation project, GTAM is necessary to meet the Commission's mandate to validate the MAOP of all gas transmission pipelines using traceable, verifiable, and complete records. MAOP Validation is necessary to allow PG&E to meet that standard today; GTAM will provide an efficient means for PG&E to meet that standard going forward. GTAM

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PG&E, as well as the NTSB and the Independent Review Panel.	will create a platform such that new information about pipeline components can be collected and maintained to a traceable, verifiable, and complete standard. GTAM will substantially improve existing natural gas pipeline information and asset management capabilities and will create a technology infrastructure that: supports enhanced and new business processes; improves data consistency and reliability; electronically maintains system data on a continuous and ongoing basis; supports improved decision making capabilities related to the risks and integrity of PG&E's gas transmission system; and consolidates multiple systems and adds capabilities to the existing systems and other critical technology components that interface with and complement PG&E's gas transmission system. While there may be other ways to comply with this new regulatory standard on an ongoing basis (e.g. an enhanced paper-based system), the GTAM Project is an efficient way to ensure compliance in the future by consolidating pipeline information into core enterprise electronic databases.
• It is premature to make any final decision that costs should be assigned to ratepayers. If any cost recovery is approved based on this limited record, rate increases should be interim and subject to refund. ○ The three pending enforcement dockets will further develop the record regarding deficient past practices of PG&E, particularly record-keeping and integrity management, and are likely to demonstrate other ways in which the PSEP is remedying PG&E's imprudence. The OII records should be particularly relevant to determining disallowances related to the GTAM, improper integrity management, and installing defective pipe segments. ○ Remedial measures ordered in the OIIs at shareholder expense are likely to include PSEP activities or affect	• Cost responsibility should be determined now in order to prevent uncertainty, delay, and wasted resources. In this proceeding, the Commission should address the scope of the work to be approved, the reasonable cost estimate for the approved scope of work, the customer/shareholder allocation principles that will determine which costs are eligible for cost recovery, and the ratemaking and rate design features necessary to implement new PSEP rates. Allegations raised in the OIIs and their appropriate fines, penalties, remedial actions and disallowances will be addressed in those proceedings. After the OIIs are decided, PG&E should be directed to adjust its PSEP rates to reflect the decisions in the OIIs that affect the PSEP.

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PSEP cost recovery. ○ The OIIs specifically contemplated taking notice of the records of those cases in this docket. Once those cases are concluded, this docket should re-visit the extent to which PSEP activities are remedying PG&E's imprudence. ○ The same cost responsibility issues will also need to be addressed for PG&E's Phase 2 PSEP, which PG&E estimates will cost between $6.9 and $9 billion.	○ This proceeding is limited to Phase 1 of PSEP. Project level detail for Phase 2 has not been planned and the cost estimate of $6.9-$9 billion is very high level. This broad estimate was developed using Phase 1 proxy costs and adjusting them to reflect the larger scope of work and the time value of money. Phase 2 timing has yet to be determined.
Recommendations Concerning Scope of Work	
Pipeline Modernization Program • Prioritization: Delay work in Class 2 non-HCA areas until later phase. Impacts about 500 miles of pipeline. • Test or Replace: PG&E should hydrotest rather than replace most pipelines with manufacturing threats operating above 30% of SMYS, rather than defaulting to replacement. Contrary to D.11-06-017, PG&E has failed to provide the criteria it will use to decide between testing and replacement. Impacts up to 124 miles of pipeline with manufacturing threats, reducing total costs by about $450 million.	Pipeline Modernization Program • Including Class 2 non-HCA is proper prioritization with the goal of enhancing safety; untested Class 2 pipeline segments operating above 30% SMYS have a greater probability of an uncontrolled rupture and public safety risk than untested Class 3 pipeline segments operating below 30% SMYS. As proposed, the inclusion of Class 2 segments represents a holistic approach that enhances safety, enhances project and program efficiency, increases pipeline piggability, reduces overall community impact from construction, and results in long-term cost savings. • Cost efficiencies can be gained by replacing pipelines with manufacturing threats as opposed to testing now and replacing later. Pipeline segments with manufacturing threats are good candidates for replacement because (1) the segments are susceptible to a higher probability of long-seam failure and less likely to pass a strength test than those not queried for replacement; (2) should these segments pass a hydrotest, their longitudinal joint efficiency factor is often the limiting variable in a pipeline that could otherwise be run at a higher pressure,

	allowing for a longer service life before a capacity upgrade is required; and (3) many of these pipeline segments have been in service for over 50 years.
• Hydrotesting Protocols: Hydrotest pressures should be at least 90% of SMYS on main lines. Low pressure strength testing just to validate the MAOP does not sufficiently assess pipeline integrity and may require duplicative future work.	• It is neither practical nor necessary to test in situ pipelines to 90% SMYS. To achieve 90% SMYS in all segments could mean that one of the pipe's segments may be stressed to well over 100% SMYS, which could potentially damage the pipe. To segment the pipelines and hydrotest for every unique pipeline segment so as to achieve this goal would dramatically increase costs, with no corresponding safety benefit. Also, no regulations require testing to 90% SMYS.
• The Commission should allow an exception from the "test or replace" requirement for pipelines operating below 30% of SMYS. Experts agree that defects on such pipelines would fail as a leak, not a rupture. Impacts over 300 miles of pipeline scheduled for hydrotesting, saving $150 million in expenses.	• PG&E submitted a PSEP that contemplates testing or replacing all previously untested DOT transmission pipeline, in compliance with Commission Decision 11-06-017. While PG&E agrees that pipelines operating below 30% SMYS are more likely to fail as a leak than a rupture, and has used the 30% SMYS level as a prioritization tool, not testing or replacing pipelines operating below 30% SMYS would not comply with Commission Decision 11-06-017 as currently crafted.
Valve Automation Program	Valve Automation Program
• Type of Valves: PG&E should install Automated Shut-off Valves ("ASV's") rather than Remote Control Valves on large diameter (above 24-inch) pipelines. Concerns about "false closure" ignore complex monitoring and programming options.	• Given the potential for false closures and PG&E's lack of experience with ASVs, PG&E proposes to install RCVs. The consequences of an inadvertent ASV closure can be significant because an ASV is likely to be falsely triggered when demand is at its peak, i.e., on a cold winter morning. Because the automated valves proposed in PSEP will be equipped with both ASV and RCV capability, the proposal to install RCVs is reasonable and appropriate.
• Prioritization: PG&E should prioritize valve automation by targeting pipelines greater than 24-inches in diameter, rather than by using the Potential Impact Radius.	• The industry standard of prioritizing valve automation by using the Potential Impact Radius (PIR) has proved to be an accurate predictor of an area within which the extent of property damage and the chance of serious or fatal injury would be expected to be significant in the event of an ignited rupture of

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• Prioritization: PG&E should closely consider automating valves in Class 1 and 2 HCA areas containing identified sites.	a gas transmission pipeline. PIR not only takes into account the pipe diameter, but also maximum allowable operating pressure, and therefore results in a more appropriate valve automation prioritization plan than TURN's proposal to consider only pipeline diameter. • Based on the clarification that automating all large pipelines in Class 1 and 2 HCA locations would require over 300 valves to sectionalize 150 segments, TURN recommended that PG&E provide additional information related to HCAs in Class 1 and Class 2. PG&E is not opposed to investigating automating Class 1 and Class 2 pipelines in HCAs as part of Phase 2 work. However, these pipeline segments are typically areas of localized population near a large diameter, high pressure pipeline.
Gas Transmission Asset Management • Independent Audit: The Commission should independently audit the GTAM project to ensure that it is meeting all objectives and requirements before allowing any rate recovery.	Gas Transmission Asset Management • PG&E agrees with TURN on the importance of measures to ensure the accuracy of information that is recorded in the Core enterprise systems (SAP and GIS). PG&E has created an Asset Knowledge Management organization that will maintain reliable records concerning installed assets and maintenance work. Within the Asset Knowledge Management organization is a Data Quality group that will test and sample the information recorded in the Core enterprise systems to continuously assess the quality of information. Creating separate groups for maintaining records and data quality provides the appropriate focus on maintaining highly reliable and accurate records.
Recommendations Regarding Ratemaking Adjustments and Accounting Mechanisms	
• The Commission should <u>reduce the ROE on PSEP capital investments</u> to prevent PG&E from turning the PSEP into a profit center.	• TURN fails to recognize the fundamental reality that investors need compensation for the use of their money. The fundamental pillar of cost-of-service regulation is that rates must include an allowed return on investment. TURN suggests that "profit" is somehow different from a return on

○ A full ROE is unwarranted in light of the IRP Report conclusion that PG&E top management was focused on financial performance and not operational safety, and the Overland Report findings that PG&E's shareholders benefitted from this insufficient regard for safety. (PG&E's average actual annual ROE for GT&S was over 3.00% higher than authorized in 1999-2010). ○ PG&E's large capital investments are necessary to fix problems of its own making and reflect decades of ineffective corporate management. The CPUC can consider these factors in reducing ROE for PSEP investments. ○ The Commission should set the authorized PSEP ROE at PG&E's cost of debt, currently 6.05%, which would reduce the present value of PG&E's revenue requirements for capital costs by 26%. ○ Alternatively, at a minimum, the Commission should reduce the ROE to 10.3%, the low end of the range of reasonable ROEs found in the last Cost of Capital proceeding.	investment. The proposed reduction in ROE would harm customers by increasing the cost of debt and capital that must be raised to finance PSEP safety improvements. ○ In considering what, if any, other ratemaking adjustments are necessary, the Commission should ask: (1) what conduct is PG&E being punished for through adoption of an ROE reduction and has this conduct already been accounted for in other actions taken in the OIIs or in this proceeding? (2) How much will the ROE reduction cost PG&E, i.e., what is the equivalent disallowance? (3) If a disallowance is implemented through an ROE reduction, will there be an impact on the utility's ability to attract debt and capital and should the Commission care if there is an adverse impact? Furthermore, PG&E's ROE is set in the Cost of Capital proceeding at a level that allows a utility to compete successfully in capital markets to obtain the funds required to meet needed investment and provide a sufficiently sound financial footing for the company to maintain its credit quality and take on debt at a reasonable price. Introducing ROE reductions in this proceeding would interfere with the Cost of capital proceeding, discourage investment in California utilities, increase market risk premiums, and ultimately impede the Commission's goal of implementing significant new gas safety enhancements in a manner that is as affordable to customers as possible.
• The Commission should require PG&E to <u>use existing internal funding sources</u> before using any ratepayer funding for PSEP as a matter of fairness and equity. ○ Bonus depreciation funds collected in authorized memorandum account pursuant to Resolution L-411	• It is unreasonable and without justification to use other sources of funding to offset PSEP costs. The external funding sources identified by TURN were authorized by prior Commission ratemaking decisions and are completely unrelated to PSEP. ○ The funds in Resolution L-411 have already been committed to incremental utility projects. Additionally,

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are appropriate to use on PSEP projects. ◦ Any future over-earnings from PG&E's gas transmission and storage (GT&S) operations in this GT&S rate case cycle should be used to offset PSEP costs, instead of being allocated to shareholders pursuant to revenue sharing mechanism. ◦ PG&E shareholders should match, via PSEP offsets, the approximately $23 million per year included in GRC rates to fund bonuses for top managers and executives.	PSEP already reflects bonus depreciation as applicable and would therefore be ineligible for tracking in the L-411 memo account. ◦ TURN's recommendation would modify the revenue sharing mechanism approved by the Commission in the Gas Accord V Settlement decision. The revenue sharing approach does not allow PG&E to "profit" by reducing spending on reliability investments. There is a balancing account for the Transmission Integrity Management Program that does not authorize PG&E to reallocate funds to other uses (and any unspent funds are returned to customers). ◦ TURN's recommendation would modify the 2011 GRC decision. Furthermore, PSEP is not the appropriate forum to adjust management compensation, since management compensation is decided in the GRC.
• The Commission should adopt a <u>longer depreciable life</u> of 60 years for PSEP pipeline replacements. ◦ The current 45-year service life was adopted by 1996 and does not reflect new testing standards or newer data. ◦ A longer service life reduces first-year capital-related revenue requirements by 4.2%, thus reducing near term rate shock without impacting total cost recovery.	• The 45-year service life was adopted in the Gas Accord V (D.11-04-031). Adopting a 60-year service life would result in a deviation from the depreciable life of transmission assets adopted in the GT&S rate case decision for non-PSEP pipe replacements. SDG&E in its current GRC has proposed a 45-year life for their gas transmission assets.
• PG&E should not fund <u>performance incentives</u> through PSEP rates. Thus, any recorded PSEP costs should *not* include costs for the Short-Term Incentive Program. The Commission should remove any STIP costs included in forecast capital expenditures (included in standard labor and corporate overheads) and expenses (included in labor loaders).	• The appropriate level of STIP is determined for the company in the GRC, not on a piecemeal basis.
• The Commission should disallow costs in recognition of <u>deferred or ineffective maintenance.</u>	• PG&E responded to the Overland Report in its June 26 testimony in the San Bruno OII.

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○ The Overland Report documents PG&E underspent by about $135 million in 1997-2010 as compared to GT&S rate case authorized revenues, indicating a strong probability of deferred maintenance. PG&E also delayed and postponed planned integrity management ILI projects in 2007-2010. ○ PG&E spent approximately $30 million in 2008-2010 on ECDA, an integrity assessment method that is of very limited value.	○ PG&E was transparent in filings to the Commission about how it intended to assess pipelines under TIMP. Direct assessment and ILI, two legally authorized assessment methods under Part 192 Subpart O regulations, were identified as the primary means of assessment in PG&E's TIMP Plan. PG&E clearly notified the Commission and parties of its TIMP implementation strategies and its rate authorization in the GT&S rate cases reflected the costs of implementing these approaches. The Commission approved PG&E's TIMP implementation strategies and funding request in the GT&S rate cases.
○ PG&E canceled previously planned pipeline replacement work (160 miles) in 2000-2010 by terminating the Gas Pipeline Replacement Program.	○ The Commission approved the reasonableness of the GPRP in numerous GRC decisions, rejected TURN's disallowance recommendations and did not find PG&E's implementation of the program to be imprudent; the transmission portion of the GPRP was transitioned to the Risk Management Program, which was a more sophisticated assessment program with a broader scope and that considered more threats and evaluated additional mitigative actions, such as assessment and testing of potential threats; the Commission Safety Branch reviewed and approved the transition of transmission pipes from the GPRP to the new Risk Management Program; and there is no evidence that PG&E received funding for transmission replacements that as of 14 years ago were not completed under the GPRP.
○ Because the record of the OIIs will further illuminate these issues, no final determinations about deferred maintenance should be made on this record.	○ There is no evidence of deferred maintenance that would result in disallowances in PSEP. Any issues found in the OIIs and their associated penalty will be addressed in the respective investigation proceeding.
• If the Commission authorizes any rate recovery based on PG&E's cost forecasts, it should reduce the forecasts and	• The proposed shareholder cost-sharing principles as set forth in PSEP ensure that ratepayers will not overpay for safety

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adopt safeguards to ensure ratepayers do not overpay. ◦ PG&E's forecast of AFUDC for expenses should be removed and its forecast of AFUDC for capital costs should be reduced, as TURN's unrebutted testimony demonstrated these forecasts are erroneous. ◦ 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.	work. ◦ As stated in PG&E's rebuttal testimony, PG&E made an error in the expense hydrotest project cost estimate detail sheets. AFUDC will not be included within the actual hydrotest project detail job estimates, and will not be included in actual rates. ◦ The objective of the proposed Tier 3 Advice letter process is not to allow PG&E to defer work or increase capital returns. Instead, it provides a timely mechanism to address the need for a mid-course correction if unanticipated circumstances make it impossible for PG&E to complete Phase 1 work at the adopted budget. This process provides a forum for collaborating with the Commission and stakeholders on a real time basis on how best to respond to the changed circumstances. The process by no means is a guarantee of cost recovery; parties will have a full opportunity to review and comment on the advice letter and the Commission may reject the request, modify it or set it for hearings if it determines that additional process is required to evaluate the request.
• The Commission should reserve the option of conducting a future <u>reasonableness review</u> of PG&E's recorded costs for PSEP work. Such a reasonableness review would be in addition to the retrospective prudence review (for a different purpose) that has already begun in this proceeding. The review should specifically analyze potential impacts on contractor costs of the need to conduct an expedited "crash program."	• As part of its ratemaking proposal, PG&E has proposed that the Commission adopt an upfront estimate of the reasonable cost to complete PSEP Phase 1. If the actual costs of the program are equal to or less than the estimate, there is no need to conduct an after the fact reasonableness review because PG&E has completed the project at or below the reasonable forecast. This ratemaking approach—adopting an upfront estimate of the reasonable costs of a project rather than conducting an after the fact prudence review of the recorded costs—is fully authorized and set out as an acceptable ratemaking approach in Public Utilities Code Section 463.5. This is the approach the Commission uses when

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<td>it adopts a “maximum reasonable cost” for utility projects requiring a Certificate of Public Convenience and Necessity under PU Code Section 1005.5. The Commission has also adopted this “upfront determination of reasonableness” approach for other large capital projects, such as PG&E’s Diablo Canyon steam generator replacement project and several of its new power plants. Under PG&E’s proposal, if it can deliver the project at the forecasted overall program cost, it has performed reasonably, customers have received what was promised and there is no need for another multi-year proceeding to review on an after the fact basis the construction and project management of the PSEP.</td>
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<td colspan="2">Recommendations Regarding Cost Allocation</td>
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The Commission should reject attempts by large noncore customers to allocate costs using the Equal Percent of Base Margin.

This method includes costs for distribution lines, service lines and customer services which are wholly unconnected to the work being done in the PSEP and thus have no basis in cost causation.
This method results in an unfair and arbitrary shift to core customers of $120 million in just the first three years of revenue requirements.
The proposal is based on the false premise that the goal of the PSEP is preventing property destruction rather than saving lives.

However, any costs for the GTAM project should be allocated separately based on total pipeline mileage.

The GTAM is a separate project wholly unrelated to the Pipeline Modernization, Valve Automation or MAOP Validation projects.
The GTAM adds IT capabilities to store data on all pipelines, not just the HCA pipelines addressed in Phase 1 of the PSEP. Its costs should thus be

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PG&E agrees with TURN; the Commission should reject proposals to use the Equal Percent of Base Margin. PG&E proposes to allocate the revenue requirement between core and noncore customers based upon their annual percentages of revenue requirement responsibility established in Gas Accord V. As TURN notes, the methodology supported by the large noncore customers is a new and novel cost allocation proposal that is “intended purely to shift costs to core (residential and small commercial) customers.”
TURN’s cost allocation proposal for GTAM intends to shift as much cost as possible to the non-residential or non-core customers. As proposed in PSEP, the cost allocation for GTAM is consistent with the manner in which common costs are allocated in the PSEP and is fair to all parties.

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functionalized differently to reflect the scope of the work performed.	