Exhibit No. ___________
Date: January 31, 2012
Witness: R. Thomas Beach

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	R.11-02-019 (Filed February 24, 2009)

PREPARED DIRECT TESTIMONY OF R. THOMAS BEACH

ON BEHALF OF

THE NORTHERN CALIFORNIA INDICATED PRODUCERS

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Crossborder Energy

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Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 316, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae*, which is **Attachment RTB-1** to this testimony.

Q: Have you testified previously before this Commission?

A: Yes, I have. A current list of the testimony that I have filed before this Commission is included in my CV.

Q: On whose behalf are you testifying today?

A: I am testifying on behalf of the Northern California Indicated Producers (NCIP). For the purposes of this proceeding, the members of NCIP include ConocoPhillips Company, Chevron U.S.A. Inc., Aera Energy LLC Inc., and Equilon Enterprises, LLC dba Shell Oil Product U.S. The NCIP consume natural gas at their oil and gas production and petroleum refining operations, and also engage in the marketing and transportation of natural gas in the PG&E service territory. These operations will be affected by the rate increases and potential service disruptions under PG&E's pipeline safety implementation plan (PSIP), which the Commission ordered PG&E to file in the aftermath of the tragic pipeline explosion on PG&E's gas pipeline system in San Bruno, California, in September 2010. As a result, NCIP members have a strong interest in PG&E's proposed PSIP.

I. SUMMARY AND RECOMMENDATIONS

Q: Please summarize the principal recommendations of your testimony.

A: Based on my review of the testimony and discovery, I recommend that the Commission:

1) **Ensure the Approved Revenue Requirements Are Spent Cost-Effectively on Safety Improvements.** In Phase 1 of PG&E's PSIP, the utility proposes to spend almost $2.2 billion in 2011-2014 to improve the safety of PG&E's gas pipeline system. The record shows that, in the past, PG&E has underspent its authorized budgets for its pipeline system. To prevent this from happening again, the Commission must approve a mechanism that requires PG&E to return to ratepayers all PSIP funds that are not used for pipeline safety projects. To ensure that the PSIP funds that are recovered from ratepayers are committed to the safety-related purposes approved by the Commission in this proceeding, the Commission should adopt a one-way balancing account as recommended by PG&E. This account will require PG&E to return funds back to ratepayers when they are not expended for approved pipeline safety purposes. In addition, the Commission should remove the loophole in PG&E's cost recovery proposal which, if PG&E is unable to complete all Phase 1 projects on budget, would allow PG&E to spend the full Phase 1 budget on a reduced scope of projects for Phase 1, and to shift the uncompleted Phase 1 projects into Phase 2 after 2014. This loophole weakens any incentive for PG&E to complete the full scope of all Phase 1 projects on time and on budget. At a minimum, PG&E should be required to obtain Commission approval for any change in either the scope or the costs for Phase 1 projects, or to fund cost or scope overruns at shareholder expense.

2) **Ensure a Reasonable Allocation of Pipeline Safety Costs Among Customer Classes:** By any measure, the utilities' implementation plans would result in substantial increases in their gas transportation rates. These rate increases for energy consumers are similar in magnitude to the anticipated new costs for these consumers in 2013 for the state's AB 32 program to regulate greenhouse (GHG) emissions. Unlike the GHG program, however, there will be no allowance value

to offset PSIP costs. I agree that all customers should bear a share of PG&E's implementation plan costs. However, the method of allocating these costs among customers should recognize, first, that core customer classes will receive almost all of the direct safety 1 benefits from the expenditures, and, second, that the proposed increases would have magnified impacts on noncore industrial customers, electric generators (EGs), electric ratepayers, and bypass of the gas system. Based on these factors, I believe allocating pipeline safety costs using an equal percent of authorized transportation margin (EPAM) methodology, a method also recommended by Southern California Gas and San Diego Gas & Electric, would be more appropriate than the allocation approach which PG&E proposes.

3) **Increase Shareholders' Responsibility for Pipeline Safety Costs.** Even before this rulemaking commenced and the legislature adopted Senate Bill 705, CPUC Section 454 and General Order 112 charged PG&E with the obligation to maintain pipeline integrity and safety. As such, the Commission must account for the failure of PG&E in the past to spend its authorized O&M expenses and capital budgets for its pipeline system. The Commission also must consider the extensive evidence of PG&E's poor record-keeping practices for its gas system. These factors support increasing the shareholders' share of PG&E's 2011-2014 pipeline safety costs beyond just the 2011 costs as proposed by PG&E. Shareholders also should bear the following amounts of 2012-2014 costs:

   - $39.3 million in unspent O&M costs and $95.4 million in unspent capital expenditures from 1999-2010.
   - The $40 million cost of pressure testing pipelines installed from July 1961 through 1970, for which the utility no longer has pressure test data.
   - The $107.1 million in PSIP costs for the maximum allowable operating pressure (MAOP) validation effort in 2012-2014 needed to update PG&E's records for its existing transmission pipelines.

In addition the Commission should reduce PG&E's return on equity for investments in its PSIP by 500 basis points (5%) from 2011 through 2014. Following this period, the Commission can review PG&E's progress in improving pipeline safety. If there are no safety incidents and PG&E's performance in implementing the PSIP has been reasonable, the Commission can consider an appropriate increase going forward in PG&E's return on equity on these investments.

Based on the above recommendations, the following table shows NCIP's overall revenue requirement recommendation for the PSIP from 2012-2015, compared to PG&E's proposal:

Table ES-1: *NCIP vs. PG&E PSIP Revenue Requirements ($ Millions)*

2012		2013	2014	Total
NCIP $111,069		$136,409	$212,140	$459,618
PG&E $247,279		$220,833	$300,641	$768,753
difference $(136,209)		$(84,424)	$(88,501)	$(309,135)
% change	-55%	-38%	-29%	-40%

4) **Limit the Operational Impacts of Pipeline Safety Disruptions.** PG&E's pipeline safety work can result in service disruptions which will have both operational and financial consequences for gas customers, particularly for large-volume noncore industrial and electric generation (EG) customers. Accordingly, as pipeline safety efforts are undertaken, PG&E should be required to provide 30 days' notice to noncore customers to warn them of minor service disruptions or reductions in pressure. Where PG&E has to curtail noncore service completely, PG&E should provide customers with six months' notice. In addition, when service disruptions or reductions do occur, PG&E should be required to provide firm backbone transportation-customers with credits to their reservation charges when customers are unable to utilize their full firm capacity due to a pressure reduction or other safety-related work. Finally, the Commission should approve a local transmission interruption credit (LTIC) mechanism under which PG&E shareholders will compensate noncore customers for local transmission service disruptions or reductions for which PG&E fails to provide adequate notice. The credit should be set at $0.25 per therm of reduced service.

II. BACKGROUND ON PURPOSE AND EVALUATION OF PSIP

Q: Please discuss the origin and purposes of this proceeding.

A: The Commission issued this order instituting investigation in response to the tragic gas pipeline explosion on the PG&E system on September 9, 2010 in San Bruno, California. This OIR is intended to be, in the Commission's words on the first page of the rulemaking, "a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines." Central to that effort is the validation of the maximum allowable operating pressure (MAOP) of existing natural gas transmission pipelines in the state, through either the testing or replacement of all lines for which there are no existing records definitively establishing the MAOP. The Commission also has announced its intent to review its own regulatory scheme for gas pipeline safety in California and to adopt changes to those regulations, particularly in the areas of construction standards, shut-off valves, inspections, operation and maintenance standards, record-keeping, ratemaking, and the application of penalties. Finally, this OIR provides a vehicle for Commission oversight of PG&E's compliance with the safety recommendations of the National Transportation Safety Board (NTSB), the Commission's Consumer Protection and Safety Division (CPSD), and the Independent Review Panel (IRP) on the San Bruno incident.

Outside of this proceeding, the Commission has instituted a companion OIR on issues concerning PG&E's record-keeping for its pipeline system (I. 11-02-016) and has established a safety phase of PG&E's most recent gas transmission and storage general rate case (GT&S GRC, A.09-09-013).

Q: What purpose is PG&E's pipeline safety plan meant to serve?

A: On June 9, 2011, the Commission issued D. 11-06-017 in this OIR. This order directed each of the state's regulated gas utilities, including PG&E, to file an Implementation Plan describing how the utility will "achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested." The Commission's goal is that, once the plans are implemented, the gas transmission lines of each gas utility will have been pressure tested, will have "traceable, complete, and verifiable records readily available," and if appropriate will be able to be inspected using in-line techniques.[1]

Q: What factors has the Commission identified to evaluate the gas utilities' pipeline safety plans?

A: D. 11-06-017 emphasizes that a "key question" is how the plans will be funded and how the costs will be recovered in rates. The Commission stressed that "obtaining the greatest amount of safety value, i.e. reducing safety risk, for ratepayer expenditures will be an overarching Commission goal in reviewing the plans."[2] In addition, the

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1 D. 11-06-017, at 19-20.
2 *Ibid.,*at 22.

Commission has required PG&E to present a proposal for how it proposes to allocate plan expenditures between ratepayers and shareholders, in recognition of the unique circumstances surrounding the San Bruno incident. PG&E's inadequate record-keeping, and the utility's past pipeline integrity programs.[3]

Q: Are there other factors that the Commission should consider in evaluating PG&E's pipeline safety plan?

A: Yes, it is important for the Commission to consider the impact of PG&E's pipeline safety plan on customers. In the aftermath of the tragic San Bruno pipeline explosion, the Commission's efforts to ensure pipeline safety are justified. At the same time, the plans provide PG&E and the other regulated gas utilities in California with an opportunity to add substantial rate base and to increase their transportation rates dramatically in a short period of time. These substantial rate increases can have adverse economic impacts on energy consumers, both gas and electric. Notably, even the recently adopted SB 705, which calls for the higher prioritization of safety, does not call for safety at any cost:

> *The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates."*[4]

Accordingly, the Commission should ensure that the magnitude, the priority, and the pace of the PG&E's proposed safety-related spending is reasonable.

In addition, it is important for the Commission to consider PG&E's pipeline safety plan in the context of both existing regulations and new legislation. California Public Utilities Code Section 451 provides that "every public utility shall…maintain such…equipment and facilities…as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." The Commission's General Order 112-E (GO 112-E) incorporates the federal rules of the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the United States Department of Transportation. The PHMSA rules regulate the design, construction, quality of

[3] *Ibid.*, at 22-23, citing R. 11-02-019, at 11-12.
[4] P.U. Code Section 963[b][4].

materials, locations, testing, operations and maintenance of natural gas pipeline facilities. In other words, even before this rulemaking commenced, PG&E was sufficiently charged with the obligation to maintain its facilities in a manner that promoted safety, and has historically included anticipated safety-related costs in its rates. As evidenced in PG&E's record-keeping proceeding (I.11-02-016), the Commission agrees that current regulations charge PG&E with the responsibility to ensure public safety:

> … the Commission's responsibilities for ensuring public safety further are defined by standards contained in the California Public Utilities Code, including in particular Section 451. PG&E's obligations to public safety are informed by federal standards, but they do not depend on federal safety rules alone.[5]

Thus, while SB 705 has elevated the priority to maintain safety,[6] PG&E's responsibility to maintain its system in a manner that ensures safety is not a new obligation. PG&E's historic spending on its pipeline system, or the lack thereof, must be viewed from this perspective.

Finally, the contemplated improvements will involve service disruptions, which can have both financial and operational impacts on customers. Service disruptions will have impacts on businesses, particularly those that are required to run 24 hours a day and seven days a week, or those, such as refineries and gas-fired power plants, for which natural gas is an essential input and a major cost. Disruptions also can have financial impacts on customers when they leave customers unable to use purchased transportation rights or unable to meet full contractual obligations to deliver electricity or other energy-intensive products. The Commission should ensure that these impacts can be minimized given the unprecedented magnitude and long-term nature of PG&E's pipeline safety efforts.

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5 I. 11-02-016, at 9.

6 Last year the Legislature enacted and Governor Brown signed SB 705 (Leno), which added Sections 961 and 963 to the Public Utilities Code. SB 705 states that "it is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority." Among other features, this new law requires each gas corporation to develop a plan for safe and reliable operation of its gas pipeline facilities, and mandates that the CPUC must accept, modify, or reject each plan by December 31, 2012.

III. ENSURING SAFETY IN A COST-EFFECTIVE MANNER

Q: Do you agree that there needs to be a new, forward-looking effort to address pipeline safety?

A: Yes. It is critical that California's natural gas infrastructure is designed, built, and operated to provide for the safe and reliable delivery of this essential fuel. The tragic San Bruno accident and its aftermath have demonstrated that there are shortcomings that must be remedied in record-keeping, in system design and operation, in the safety culture of the utilities, and in the Commission's enforcement program. I agree that additional immediate and long-term investments in the gas transmission system should be made. At the same time, however, the implementation plans provide the gas utilities with an opportunity to add substantial rate base and to increase their transportation rates dramatically, in a short period of time. The Commission's focus should not be on safety at any cost. I am heartened that the Commission has declared that the "overarching Commission goal" is "obtaining the greatest amount of safety value, i.e. reducing safety risk, for ratepayer expenditures." The Independent Review Panel (IRP) on the San Bruno incident has also emphasized the importance of considering tradeoffs that include ratepayer costs:

> We assume PG&E wants regulators to agree to hundreds of millions or billions of dollars in improvements to its system to assure public safety. The Panel believes for ratepayers to be responsible in the future for investments (some of which, arguably, should have been made already), PG&E must be prepared to support its request for rate recovery with a thorough delineation of its long-term capital program, including the specification of the alternatives considered and an appraisal of the tradeoffs among safety, effectiveness, and cost for each alternative approach.[7]

I discuss these tradeoffs in more detail below, with an emphasis on how the costs are allocated among customer classes and between ratepayers and shareholders.

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[7] "Report of the Independent Review Panel" (IRP Report) on the San Bruno incident, released June 9, 2011, at page 14. Available at http://www.cpuc.ca.gov/PUC/events/110609_sbpanel.htm .

A. Pipeline Safety Revenue Requirement

Q: How does PG&E's pipeline safety plan attempt to improve the safety of its gas pipeline system, including the replacement and/or testing of all natural gas transmission pipelines that have not been pressure tested or for which such records do not exist?

A: On August 26, 2011, PG&E and the other gas utilities filed their implementation plans in response to D. 11-06-017. PG&E's plan proposes to spend almost $2.2 billion in 2011-2014 to implement Phase 1 of its plan. As shown in Tables 1-2 and 1-3 of PG&E's testimony, PG&E's expenditures include $751 million in expenses and $1,433 million in capital. By 2014, the added capital would increase PG&E's rate base for its gas transmission and storage system by over 70%.[8] The bulk of the expenses ($500 million, including contingency) and capital ($1.1 billion, including contingency) would be spent on pipeline replacement and modernization. Smaller amounts will be spent on valve automation and on new record-keeping systems.

PG&E has asked the Commission to approve its proposed budget for these activities, and has proposed that, to the extent that it does not spend the authorized funds, those monies will be returned to ratepayers. PG&E also has proposed to obtain Commission approval to exceed its approved budget for specified plan activities. In essence, this is a "one-way" balancing account similar to the one established for pipeline integrity costs in PG&E's last GT&S general rate case, which resulted in the "Gas Accord V" settlement approved in D. 11-04-031. PG&E also proposes that, if it cannot complete the full scope of its Phase 1 activities at the Commission-authorized budget, it be authorized to move some Phase 1 projects to Phase 2 (i.e. to be performed after 2014).

Q: Do you have any concerns with PG&E's proposed pipeline safety revenue requirement?

A: Yes. As noted above, I agree that additional immediate and long-term investments in the safety of PG&E's gas transmission system should be made. At the same time,

[8] Based on a 2014 GT&S rate base of $2.006 billion approved in D. 11-04-031.

however, PG&E's PSIP proposal should be carefully scrutinized to ensure that it does not duplicate the transmission integrity management program (TIMP) activities funded through the Gas Accord V settlement and PG&E's current transmission rates. I have asked PG&E in discovery about a number of PSIP projects that appear to overlap with TIMP projects. To date, PG&E's responses appear to show that there is no duplication between PSIP and TIMP; these responses are included in **Attachment RTB-2**. I also recommend that TIMP projects should be subject to the same decision tree analysis used to evaluate PSIP projects, so that there is a consistent process used to justify the expenditures under both programs. In general, PG&E should not be permitted to recover duplicative funds for projects whose costs PG&E already has been authorized to recover in rates. In addition, to ensure that ratepayers are only responsible for those pipeline safety costs that PG&E actually incurs, all of PG&E's pipeline expenditures should be subject to one-way balancing account treatment as recommended by PG&E. This will ensure that where PG&E does not use safety-related revenues for pipeline safety projects, the money will be returned to ratepayers.

Finally, PG&E's proposal to move unfinished Phase 1 projects into Phase 2 if the approved Phase 1 budget is reached creates a significant loophole that compromises the value to ratepayers of the one-way balancing account protection and of Phase 1 cost controls. I find this proposal unreasonable. If there are cost overruns in Phase 1, even if the Commission does not allow the Phase 1 budget to be increased to cover such overruns, PG&E would retain the option simply to shift other work out of Phase 1 and into Phase 2. This would allow PG&E to recover the costs overruns in Phase 1 and expose ratepayers to higher costs in Phase 2 to complete the scope of work contemplated for Phase 1. Effectively, this places ratepayers at risk for Phase 1 cost overruns regardless of whether the Commission finds that such excess spending is reasonable. Accordingly, to close this loophole, I recommend that PG&E also be responsible for completing the full scope of Phase 1 in 2012-2014, unless the Commission explicitly approves such a scope change. If the Commission does not approve a change in the Phase 1 scope, the shareholders should be required to fund the Phase 1 projects that are delayed until Phase 2, i.e. until after 2014. PG&E also should be required to seek approval for any increases in its pipeline safety revenue requirement.

B. Pipeline Safety Cost Allocation Proposal

Q: How does PG&E propose to recover pipeline safety plan costs from ratepayers?

A: PG&E proposes to recover the costs of its plan through a separate Gas Pipeline Safety (GPS) charge included in the Customer Class Charge of the rates of PG&E's end-use customers. PG&E does not plan to modify the local and backbone transmission rates for 2011-2014 included in the Gas Accord V settlement filed with the Commission in August 2010 and approved in D. 11-04-031, even though the bulk of the costs of PG&E's plan would be spent to improve the safety of PG&E's local and backbone transmission systems. While PG&E proposes to recover the costs through a separate pipeline safety surcharge, it plans to use the same customer class allocation mechanism that applies to other local transmission, backbone transmission, and storage costs. For example, the bulk of PG&E's implementation plan costs are for enhancements to its local transmission system; thus, PG&E proposes to allocate these costs among its customer classes on the basis of January throughput.

To simplify the development of the pipeline safety surcharge, PG&E proposes two average GPS rates: one for the combined core customer classes and another for the combined noncore classes. PG&E's proposed core and noncore GPS rates are shown in **Table 1**. PG&E's cost allocation proposal reveals that the core and noncore classes would bear 60% and 40%, respectively, of the 2012-2014 revenue requirements for PG&E's plan.

Table 1: *PG&E PSIP Costs and Charges*

Market	2012-14 PSIP Revenue Requirements (millions)	%	GPS Charge ($/Dth)
Core	$449	60%	$0.51
Noncore (local T service)	$295	40%	$0.27

Source: PG&E PSIP workpapers for Chapter 10.

Q: What impacts will PG&E's allocation mechanism have on different customer classes?

A: By any measure, the utilities' implementation plans would result in substantial increases in their transportation rates. For example, PG&E is proposing an immediate 86% increase in the gas transportation rates applicable in 2012 to the EG customers on its system served from the local transmission system.[9] By 2014, PG&E's EG transportation rate for local transmission customers would more than double from its current level. Based on a January 2012 commodity cost of gas of $3.40 per MMBtu in the PG&E's City-gate market, plus the existing PG&E Schedule G-EG transportation rate (non-backbone) of $0.31 per Dth, PG&E's proposal represents an increase of 7% in the overall burner-tip cost of natural gas for large noncore customers. PG&E tries to minimize the impact of these rate increases by calculating noncore rate increase using the core commercial cost of gas as the proxy for the noncore commodity cost of gas. However, in these calculations PG&E's use of the core commercial cost of gas significantly overstates what noncore customers typically pay in gas commodity costs. PG&E's January 2012 core commercial cost of gas is $4.71 per MMBtu. In comparison, the PG&E city-gate price is more typical of the gas commodity costs that noncore customers pay, and is $3.40 per MMBtu in January 2012. Table 10-4 of PG&E's testimony thus significantly understates the impact of its plan on noncore customers, in terms of the percentage increase in the burner-tip cost of gas.

Table 9-2 of PG&E's testimony shows that the annual revenue requirement for PG&E's plan averages $256 million from 2012-2014, reaching $301 million in 2014. In 2014, this represents a 52% increase in the $579 million PG&E GT&S revenue

9 PG&E Testimony, at Tables 10-2 and 10-3.

requirement approved in D. 11-04-031. To put this in perspective, these new costs are similar in magnitude to PG&E's anticipated new costs in 2013 to purchase GHG allowances under the state's AB 32 program to regulate GHG emissions.[10] Importantly, concerns about GHG price increases and the resulting trade exposure of the California economy have caused the California Air Resources Board (CARB) to designate a number of California industries, including petroleum production and refining, as energy-intensive, trade-exposed (EITE) industries. As such, CARB has expressed concerns that significant California-specific rate increases for EITE entities as a result of its GHG regulations could lead to a significant loss (known as "leakage") in economic activity to competitors outside of the state. To forestall such leakage, CARB will allocate free emission allowances to certain EITE industries. Since the cost increases to many PG&E noncore customers from PG&E's proposed PSIP cost allocation are comparable to those from GHG regulation, the Commission should consider an alternative cost allocation mechanism that provides exposed entities with cost mitigation compared to PG&E's proposal.[11]

Q: Does PG&E explain its rationale for the allocation of pipeline safety costs in this manner?

A: No, PG&E's testimony does not offer any justification for the use of the existing cost allocation to distribute the costs of this extraordinary safety surcharge among its customer classes, other than that this is the allocation mechanism used in its current regular transmission and storage rates.

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[10] PG&E filed a detailed (but confidential) forecast of its expected 2012 GHG obligations in its June 2011 ERRA (A. 11-06-004). The starting date for those obligations has now been delayed until 2013. The public E3 GHG calculator projects PG&E's 2013 GHG obligations to be about 18 million metric tonnes under a scenario of a 33% RPS and aggressive energy efficiency goals. The most recent version 3c of the E3 GHG calculator is available at http://www.ethree.com/public_projects/cpuc2.php . Assuming an allowance price of $16 per tonne, PG&E would spend approximately $290 million in 2013 on GHG allowances. (Commission Resolution E-4442, at 8-13 and Appendix E, projects a statewide GHG allowance cost of $16.27 per ton in 2013.) This is very similar to the incremental annual cost from 2012-2014 of PG&E's proposed pipeline safety implementation plan.

[11] In addition, the Commission has an ongoing proceeding (R. 11-03-012) that is expected to mitigate GHG costs for retail electricity consumers, by allocating to consumers at least a portion of the revenues from the electric utilities' auction of free GHG allowances associated with retail electricity. In fact, in that case PG&E and the other electric utilities have stated that mitigating the costs of GHG regulation for electricity consumers is a "critical" policy goal, while preventing economic leakage is a "very important" objective. "Joint Proposal Of Pacific Gas And Electric Company, Southern California Edison Company, and San Diego Gas &Electric Company on the Appropriate Use of Allowance Auction Revenues," filed October 5, 2011 in R. 11-03-012, at 8-14.

Q: Do you believe that there is a preferable means to allocate these extraordinary costs among PG&E's customer classes?

A: Yes. I believe the equal percent of authorized margin (EPAM) methodology proposed by San Diego Gas & Electric and Southern California Gas (SDG&E/SoCalGas, or the Sempra utilities) is a more appropriate way to allocate PG&E's pipeline safety costs to customers. Like PG&E, SDG&E/SoCalGas propose to recover pipeline safety costs using a separate Pipeline Safety Enhancement Program (PSEP) surcharge. However, unlike PG&E, the Sempra utilities propose to allocate the costs to customer classes using an EPAM allocation methodology, which differs from the allocation mechanism used for its other backbone transmission, local transmission and storage costs. Under an EPAM allocation, all customers would bear rate increases that are an equal percentage increase in the base margin portion of their transportation rates. **Table 2** shows the Sempra utilities' proposed allocation of the costs of their plan between the core and noncore markets.

Table 2: *Sempra Utilities' PSEP Costs, 2012 - 2015*

SoCalGas / SDG&E	2012-15 PSEP Revenue Requirements (millions)	%
Core	$601	93%
Noncore	$43	7%
Total	644	100%

Source: SDG&E/SoCalGas PSEP workpapers.

Q: What is SDG&E/SoCalGas' rationale for allocating pipeline safety costs to customers using the EPAM method?

A: SDG&E/SoCalGas observe that an EPAM allocation mechanism would be appropriate because enhancing the safety of its gas transmission pipelines will benefit all customers equally. They note that an EPAM mechanism allocates costs in a manner that results in a percentage rate increase that is "relatively equitable across our different customer classes."[12] They also use this mechanism to allocate cost increases that occur between

[12] SDG&E/SoCalGas Testimony in R. 11-02-019, at 22.

cost allocation proceedings.[13] This mechanism, when compared to the methods with which other backbone transmission, local transmission, and storage costs are allocated, results in shifting less costs to noncore customers, but the Sempra utilities note that this result is justified. They observe that the Commission has committed to a gas pipeline safety program that goes well beyond current Federal safety standards for pipelines (including the interstate pipelines that compete with the California utilities for customers), and that the proposed improvements will not result in a significant improvement in CPUC-regulated transmission service for large noncore customers. On the other hand, the use of the existing transmission cost allocation would result in very large rate increases for noncore customers, which, the Sempra utilities state, "would likely encourage most, if not all, of these customers to eventually seek service from FERC-regulated transmission pipelines that are not required to recover the additional pipeline safety costs being ordered in this California proceeding."[14]

Q: Are there other reasons an EPAM methodology should be used to allocate pipeline safety costs?

A: Yes. First, data from SDG&E/SoCalGas clarifies that 97% of the premises structures found within the Potential Impact Radius (PIR) of their transmission pipelines are typically those associated with core residential and commercial customers.[15] Obviously, customers who live or work within the PIR of a gas transmission line will receive the direct benefits of enhanced safety, in terms of reducing their own risk of harm from a pipeline incident. PG&E's response to a comparable data request states that it does not record building types when surveying the PIRs surrounding its pipelines.[16] Nonetheless, I see no reason why the SoCalGas/SDG&E data should not be comparable to the circumstances on the PG&E system. This data demonstrates that almost all of the direct safety benefits of the utilities' plans will accrue to core customers. Thus, the EPAM methodology is more appropriate given that core customers will realize almost all of the direct safety benefits of a reduced likelihood of catastrophic harm from incidents such as

[13] *Ibid.,*at 22, footnote 17.
[14] *Ibid.*, at 23.
[15] *See* SCG-SDG&E response to Watson-SCIP Data Request No. 1, Questions 5-6, which are included in **Attachment RTB-2**.
[16] PG&E response to NCIP Data Request 003-Q01, included in **Attachment RTB-2**.

San Bruno. I do recognize that all customers will realize the indirect benefits of these safety improvements, which are principally the enhanced reliability of a more robust and resilient gas system that has a reduced risk of safety-related interruptions.

Second, a dramatic increase in noncore transportation rates is likely to increase bypass of the gas utilities' systems. Over the last ten years, about 4,300 MW of efficient gas-fired combined-cycle power plants connected to interstate pipelines or California production have been built in California,[17] and the percentage of statewide noncore (industrial / EOR / EG) gas use served from non-utility pipelines has increased, as shown by the *California Gas Report* data in **Table 3**.

Table 3: *Annual Noncore Gas Use in MMcf/d, from* ***California Gas Report*** *Data*

Serving Gas Utility / Pipeline	1999	2009
PG&E 1,265		1,337
SoCalGas-SDG&E 1,329		1,232
Non-utility pipeline	1,098	1,341
Total Noncore	3,692	3,910
> Non-utility as a % of Total	**29.7%**	**34.3%**

In short, the Commission should be concerned with the long-term impact on gas utility rates of such bypass, either physical bypass or "bypass by wire" as gas throughput shifts to electric generators supplied from non-utility pipelines.

Third, the significant noncore rate increase that PG&E proposes will have a significant impact on energy-intensive, trade-exposed industries in California. As noted above, the rate increases contemplated by pipeline safety efforts are similar in magnitude to rate increases associated with AB 32 implementation. These rate increases have caused regulators to be concerned about trade exposure. In fact regulators are in the process of addressing the distribution of allowance value to mitigate this threat of trade exposure. Stated differently, regulators are concerned that significant increases in

[17] *See* the California Energy Commission power plant licensing data base, at http://www.energy.ca.gov/sitingcases/all_projects.html#approved . Sunrise, LaPaloma, Elk Hills, Blythe, High Desert, Pastoria. Calpine also operates a proprietary pipeline system in northern California that can deliver significant amounts of California production to some of its power plants in PG&E's service territory.

energy costs will cause industries to move out of the state. That is something that also should be considered in this proceeding when cost allocation mechanisms are evaluated.

Fourth, PG&E's proposed allocation mechanism will significantly compromise the ability of EG customers on the PG&E system to compete. Natural gas comprises almost all of the variable costs of a gas-fired generator. PG&E's allocation would increase its EG transportation rate for the EG customers on its local transmission system by $0.25 per MMBtu in 2012 and $0.32 per MMBtu in 2014, amounting by 2014 to roughly doubling the current EG transportation rate.[18] Based on current gas commodity prices and transportation rates,[19] these surcharges will increase the burnertip gas costs of PG&E EG customers by 4% compared to an allocation based on EPAM. Such cost increases would put generators on the PG&E system at a corresponding disadvantage in the competitive wholesale electric market, and could result in a long-term shift in EG throughput to generators not served from the PG&E system who do not have to pay such surcharges. These competitors could be out-of-state producers or in-state generators who take direct service from interstate pipelines or California production.

Finally, higher gas transportation rates will lead to higher electric rates. Moreover, electric rates will increase by more than simply the increase in gas transportation costs. There are a number of reasons for this "multiplier effect":

- Wholesale electric market prices are based on the costs of the marginal generator, which is likely to be a higher-cost generator that pays the new PG&E or SDG&E/SoCalGas safety surcharges. Thus, the market-clearing wholesale electric prices in the state are likely to increase as a result of the new surcharges. All market generators receive the market-clearing price, even gas-fired EGs who receive gas from interstate pipelines or California production and thus who will not pay the new surcharges. Gas-fired generation is the largest single source of electricity in the state, producing 109,481 GWh of power in 2010 (38% of statewide generation).[20]

- The California electric utilities import significant amounts of power from out-of-

[18] PG&E Testimony, at Table 10-2.
[19] Based on a PG&E City-gate price of $4.00 per MMBtu, a PG&E G-EG rate of $0.31 per MMBtu, and the municipal surcharge of $0.03 per MMBtu.
[20] *See* detailed CEC electric generation data by source: http://energyalmanac.ca.gov/electricity/electricity_generation.html .

state sources. For example, according to CEC data, in recent years the state has imported about 30% of its power from out of state.[21] About 15% of the imports are associated with shares of out-of-state coal plants owned by California utilities. The pricing for the remaining 85% of imports (about 72,000 GWh in 2010)[22] – and in particular the imports of short-term energy – will be influenced both by electric market prices in California as well as by generation costs in the other western states where the imports are produced. Thus, increases in electric market prices in California as a result of higher gas transportation surcharges will raise the state's cost for a substantial portion of the imported electric energy on which California relies.

- Many electric resources that do not burn gas are priced with formulas that include the gas utilities' tariffed EG transportation rates. For example, the electric utilities purchase significant amounts of renewable generation at short-run avoided cost (SRAC) energy prices. CPUC Renewable Portfolio Standard (RPS) data shows that the three major electric utilities are purchasing about 15,000 GWh per year of renewable generation under qualifying facility (QF) contracts that predate the RPS program, and thus that are priced on SRAC-based energy prices.[23] The current SRAC energy pricing formulas explicitly include the PG&E and SoCalGas-SDG&E tariffed EG transportation rates.[24] These prices will rise as the new safety surcharges are implemented. Other electric procurement programs whose prices include EG transportation rates include the AB 1613 and AB 1969 feed-in tariff programs for combined heat and power and small renewable generators, respectively.

Q: Can you estimate the size of this EG rate "multiplier effect"?

A: Yes, I can approximate the size of this multiplier effect. Unless an EPAM allocation is adopted, the proposed PG&E and SoCalGas-SDG&E gas surcharges will increase EG transportation rates for local transmission-level EG customers by about $0.19 per MMBtu. EG throughput on the three gas utilities' local transmission systems is about 1,457 MDth per day, so the surcharges will increase direct EG gas costs by about $100 million per year.[25] An increase of $0.19 per MMBtu in the cost of marginal electric

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21 *Ibid.,* alsoCEC power source data, http://energyalmanac.ca.gov/overview/energy_sources.html .

22 *Ibid.*

23 This data is derived from the Commission's RPS data bases, at http://www.cpuc.ca.gov/PUC/energy/Renewables/compliance.htm , including the the utilities' individual August 2011 RPS compliance reports.

24 For example, see PG&E's monthly SRAC price posting at http://www.pge.com/b2b/energysupply/qualifyingfacilities/prices/index.shtml . The electric utilities periodically negotiate fixed prices with their renewable QFs, as an alternative to monthly SRAC prices. Obviously, the level of these fixed price offers (and whether QFs accept them) will be influenced by anticipated SRAC energy prices, including the impacts of any gas transportation surcharges included in SRAC prices.

25 PG&E's EG throughput forecast for 2011, at the local transmission level, is 429 MDth per day, from

generation with a market heat rate of 8,000 Btu per kWh will raise electric market prices by $1.50 per MWh. Assuming that such an increase will impact the cost for electric ratepayers of (1) in-state gas-fired generation (109,000 GWh), (2) 50% of electricity imports (36,000 GWh), and (3) SRAC-priced renewable generation (15,000 GWh), the increase in electricity costs is $1.50 per MWh times 160,000 GWh per year, or $240 million per year. This is about **2.4 times** the direct increase in gas costs for electric generators, and is the approximate magnitude of the "multiplier effect" on electric rates. An EPAM allocation will moderate the impact of the new safety costs on the gas transportation rates paid by electric generators, and thus will significantly reduce the impact of these new costs on electric ratepayers, compared to PG&E's proposal. As shown in **Table 4** below, an EPAM allocation will reduce the safety-related charge for electric generators served from P&&E's local transmission system by about $0.19 per MMBtu.

Q: Have you calculated an EPAM allocation of PG&E's pipeline safety costs?

A: Yes, I have. PG&E's distribution and local transmission costs are bundled together in PG&E's authorized margin for its end use transportation rates, so I have allocated the PSIP's local transmission costs to customer classes based on an equal percentage of PG&E's authorized margin for its end use transportation rates. I then have allocated safety-related backbone and storage costs based on an equal percentage share of the core's and noncore's respective backbone and storage costs, separately, as these services are unbundled. The result is that 76.5% of 2012-2014 pipeline safety costs are allocated to core customers, and 23.5% to noncore users. I note that this allocates a substantially lower share of pipeline safety costs to the core than does the SDG&E/SoCalGas EPAM allocation of its PSEP costs, and is a result of PG&E's unbundled backbone and storage costs.

I have performed this allocation separately for each PG&E customer class, instead of PG&E's allocation which averages costs across the entire core and noncore

PG&E's Chapter 10 workpapers. SoCalGas' EG throughput forecast for 2011 in the *2010 CGR*, at page 105, is 1,028 MDth per day.

markets and thus creates just two new safety charges, one for the core and another for the noncore. I have created a separate safety surcharge for each customer class because there are significant differences in the authorized margin for transportation service within the core and noncore markets. For example, residential and large commercial (G-NR2) core customers pay significantly different rates and have significantly different allocations of the authorized transportation margin. As a result, I recommend a distinct PSIP safety charge for each customer class. The results of my recommended EPAM allocation of PSIP costs are presented in **Table 4**, which shows average PSIP surcharges over the Phase 1 period of 2012-2014, and compares them to the PG&E proposed charges. **Table 5** is a breakdown of my proposed safety rates by year from 2012-2014, and **Table 6** shows the resulting rate changes.[26] The NCIP-proposed rates shown in Tables 4 and 5 also include the impacts of the sharing of PSIP costs between ratepayers and shareholders which I recommend in Section III.C below. As shown in Table 4, my recommended rates are lower than those proposed by PG&E for every customer class.

Table 4: *Proposed Average Safety Rates, 2012-2014 ($ per Dth)*

Average Safety Rates 2012-2014 *($ per Decatherm)*	**PG&E Proposal**	**NCIP Proposal**
Core	$ 0.513	$ 0.402
Residential		$ 0.419
Small commercial (G-NR1)		$ 0.373
Large commercial (G-NR2)		$ 0.231
Core NGV		$ 0.419
Noncore: Local Transmission/Distribution Level	$ 0.267	$ 0.092
Industrial distribution		$ 0.213
Industrial transmission		$ 0.084
Electric generation – Local T Level		$ 0.080
Noncore NGV		$ 0.077
Wholesale		$ 0.081
Noncore: Backbone Level	$ 0.062	$ 0.038

Sources: PG&E Errata Rate Model; NCIP modified RO and Rate Models.

[26] The Table 6 rate changes are relative to June 2011 class average transportation rates, but use January 2012 procurement rates, including the PG&E City-gate gas price for noncore customer classes.

Table 5

Summary of NCIP's Recommended Gas Pipeline Safety Rates

($ per Therm)

Line No.		2012	2013	2014	Average
1	**Core Customer Classes**				
2	Residential	$0.03056	$0.03781	$0.05720	**$0.041855**
3	Small Commercial	$0.02709	$0.03360	$0.05117	**$0.037288**
4	Large Commercial	$0.01665	$0.02049	$0.03210	**$0.023078**
5	Natural Gas Vehicle (Compressed)	$0.03026	$0.03775	$0.05755	**$0.041854**
6	Natural Gas Vehicle (Uncompressed)	$0.03026	$0.03775	$0.05755	**$0.041854**
	Noncore Customer Classes				
7	Industrial - Distribution	$0.01552	$0.01898	$0.02926	**$0.021253**
8	Industrial - Local Transmission	$0.00606	$0.00719	$0.01206	**$0.008437**
9	Industrial - Backbone Transmission	$0.00279	$0.00298	$0.00563	**$0.003800**
10	Electric Generation (Distribution/Local Transmission)	$0.00564	$0.00688	$0.01156	**$0.008030**
11	Electric Generation (Backbone Transmission)	$0.00279	$0.00298	$0.00563	**$0.003800**
12	Natural Gas Vehicle - Distribution (Uncompressed)	$0.00535	$0.00643	$0.01117	**$0.007651**
13	Natural Gas Vehicle - Transmission (Uncompressed)	$0.00535	$0.00643	$0.01117	**$0.007651**
14	Wholesale Customers				
15	Alpine Natural Gas	$0.00577	$0.00684	$0.01158	**$0.008065**
16	Coalinga	$0.00577	$0.00684	$0.01158	**$0.008065**
17	Island Energy	$0.00577	$0.00684	$0.01158	**$0.008065**
18	Palo Alto	$0.00577	$0.00684	$0.01158	**$0.008065**
19	West Coast Gas - Castle	$0.00577	$0.00684	$0.01158	**$0.008065**
20	West Coast Gas - Mather Distribution	$0.00577	$0.00684	$0.01158	**$0.008065**
21	West Coast Gas - Mather Transmission	$0.00577	$0.00684	$0.01158	**$0.008065**

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Table 6

Total Rate Change Summary

(Percentage Changes are Relative to Class Average Gas Transportation Rates Effective June 1, 2011, and use January 2012 Procurement Proxies)

Line No.		2011 Rate Change ($/Therm) (A)	2011 Rate Change (%) (B)	2012 Rate Change ($/Therm) (C)	2012 Rate Change (%) (D)	2013 Rate Change ($/Therm) (E)	2013 Rate Change (%) (F)	2014 Rate Change ($/Therm) (G)	2014 Rate Change (%) (H)
1	**Core Bundled Customer Classes**								
2	Residential	$0.00000	0.00%	$0.03056	2.73%	$0.03781	3.38%	$0.05720	5.11%
3	Small Commercial	$0.00000	0.00%	$0.02709	3.03%	$0.03360	3.76%	$0.05117	5.73%
4	Large Commercial	$0.00000	0.00%	$0.01665	2.32%	$0.02049	2.85%	$0.03210	4.47%
5	Natural Gas Vehicle (Uncompressed)	$0.00000	0.00%	$0.03026	4.99%	$0.03775	6.23%	$0.05755	9.49%
6	Natural Gas Vehicle (Compressed)	$0.00000	0.00%	$0.03026	1.63%	$0.03775	2.03%	$0.05755	3.10%
7	**Core Transport Only**								
8	Residential	$0.00000	0.00%	$0.03056	4.70%	$0.03781	5.81%	$0.05720	8.80%
9	Small Commercial	$0.00000	0.00%	$0.02709	6.48%	$0.03360	8.04%	$0.05117	12.24%
10	Large Commercial	$0.00000	0.00%	$0.01665	6.71%	$0.02049	8.26%	$0.03210	12.94%
11	**Noncore Transport Only**								
12	Industrial - Distribution	$0.00000	0.00%	$0.01552	9.07%	$0.01898	11.09%	$0.02926	17.10%
13	Industrial - Local Transmission	$0.00000	0.00%	$0.00606	8.74%	$0.00719	10.36%	$0.01206	17.39%
14	Industrial - Backbone Transmission	$0.00000	0.00%	$0.00279	6.60%	$0.00298	7.04%	$0.00563	13.31%
15	Electric Generation (Distribution/Local Transmission)	$0.00000	0.00%	$0.00564	19.45%	$0.00688	23.72%	$0.01156	39.86%
16	Electric Generation (Backbone Transmission)	$0.00000	0.00%	$0.00279	37.45%	$0.00298	40.00%	$0.00563	75.57%
17	Natural Gas Vehicle - Distribution (Uncompressed)	$0.00000	0.00%	$0.00535	3.46%	$0.00643	4.16%	$0.01117	7.22%
18	Natural Gas Vehicle - Local Transmission (Uncompressed)	$0.00000	0.00%	$0.00535	9.70%	$0.00643	11.66%	$0.01117	20.26%
19	**Noncore with PG&E City-gate Procurement Rate Proxy**								
20	Industrial - Distribution	$0.00000	0.00%	$0.01552	3.04%	$0.01898	3.71%	$0.02926	5.72%
21	Industrial - Local Transmission	$0.00000	0.00%	$0.00606	1.48%	$0.00719	1.76%	$0.01206	2.95%
22	Industrial - Backbone Transmission	$0.00000	0.00%	$0.00279	0.73%	$0.00298	0.78%	$0.00563	1.47%
23	Electric Generation (Distribution/Local Transmission)	$0.00000	0.00%	$0.00606	1.64%	$0.00719	1.95%	$0.01206	3.27%
24	Electric Generation (Backbone Transmission)	$0.00000	0.00%	$0.00279	0.80%	$0.00298	0.86%	$0.00563	1.62%
25	Natural Gas Vehicle - Distribution (Uncompressed)	$0.00000	0.00%	$0.00535	1.08%	$0.00643	1.30%	$0.01117	2.26%
26	Natural Gas Vehicle - Transmission (Uncompressed)	$0.00000	0.00%	$0.00535	1.35%	$0.00643	1.63%	$0.01117	2.83%
27	**Wholesale Transport Only**								
28	Alpine Natural Gas	$0.00000	0.00%	$0.00577	22.46%	$0.00684	26.63%	$0.01158	45.08%
29	Coalinga	$0.00000	0.00%	$0.00577	22.39%	$0.00684	26.54%	$0.01158	44.94%
30	Island Energy	$0.00000	0.00%	$0.00577	21.04%	$0.00684	24.94%	$0.01158	42.22%
31	Palo Alto	$0.00000	0.00%	$0.00577	22.81%	$0.00684	27.04%	$0.01158	45.77%
32	West Coast Gas - Castle	$0.00000	0.00%	$0.00577	5.77%	$0.00684	6.83%	$0.01158	11.57%
33	West Coast Gas - Mather Distribution	$0.00000	0.00%	$0.00577	4.68%	$0.00684	5.54%	$0.01158	9.38%
34	West Coast Gas - Mather Transmission	$0.00000	0.00%	$0.00577	22.20%	$0.00684	26.32%	$0.01158	44.56%
35	**Wholesale with PG&E City-gate Procurement Rate Proxy**								
36	Alpine Natural Gas	$0.00000	0.00%	$0.00577	1.58%	$0.00684	1.87%	$0.01158	3.17%
37	Coalinga	$0.00000	0.00%	$0.00577	1.58%	$0.00684	1.87%	$0.01158	3.17%
38	Island Energy	$0.00000	0.00%	$0.00577	1.57%	$0.00684	1.86%	$0.01158	3.15%
39	Palo Alto	$0.00000	0.00%	$0.00577	1.58%	$0.00684	1.87%	$0.01158	3.17%
40	West Coast Gas - Castle	$0.00000	0.00%	$0.00577	1.31%	$0.00684	1.55%	$0.01158	2.63%
41	West Coast Gas - Mather Distribution	$0.00000	0.00%	$0.00577	1.25%	$0.00684	1.48%	$0.01158	2.50%
42	West Coast Gas - Mather Transmission	$0.00000	0.00%	$0.00577	1.58%	$0.00684	1.87%	$0.01158	3.16%

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Q: Core customers and smaller noncore customers are served from the gas distribution system. The authorized transportation margin allocated to these customers includes significant distribution costs. An EPAM allocation based on a transportation margin that includes distribution costs will allocate more costs to core and smaller noncore customers whose transportation margin includes distribution costs. Why is it fair to use EPAM when the utilities' implementation plans do not involve significant distribution-related costs?

A: The purpose of this OIR, on its face, is to "to adopt new safety and reliability regulations for natural gas transmission **and distribution** pipelines" (emphasis added). Fundamentally, the purpose of this OIR is to create a new safety culture at the California gas utilities, and a new regulatory regime at the Commission, that will improve safety at all levels of the gas system. Many aspects of this OIR will impact safety at the distribution level, including improved record-keeping, possible changes to distribution-related portions of GO 112-E, a new system of Commission oversight and penalties, improved information for and coordination with first responders, increased information on the gas system for the public, and the development of more comprehensive catastrophic risk assessments.[27] As one example of such overlap, the PG&E implementation plan includes provisions for enhanced coordination with first responders.[28] In addition, as described above, smaller customers will realize most of the direct safety benefits of the implementation plans. I thus agree with SoCalGas and SDG&E that it is the total authorized margin for transportation service, including both transmission and distribution services, that best approximates the value of these safety improvements to each customer class. Using EPAM, each gas customer will pay a new safety surcharge that is approximately the same percentage of the base margin portion of their overall transportation rate. The base margin covers the fixed infrastructure costs of the gas utility's pipeline system, and thus is a reasonable measure of the value of the transportation service that each gas customer receives. EPAM provides that each customer will pay an equal percentage surcharge to enhance the safety of the gas infrastructure that serves them.

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27 R. 11-02-019, at 3-15.

28 PG&E Testimony, at 6-15 to 6-16.

C. Sharing of Safety Costs Between Ratepayers and Shareholders

Q: How does PG&E propose to split responsibility for pipeline safety expenditures between shareholders and ratepayers?

A: PG&E has proposed that its shareholders will fund 2011 costs, including $220 million in expenses and $1.6 million in capital, representing about 10% of the costs of PG&E's plan ($222 million out of $2,184 million). PG&E also proposes to have its shareholders cover the costs of MAOP validation and strength testing of post-1970 pipelines, about $97.7 million over 2011-2014, including $58.7 million in 2012-2014.

Q: Do you have any concerns with PG&E's proposal to share expenditures between shareholders and ratepayers?

A: Yes. As a preliminary matter, Public Utilities Code Section 451 provides that "every public utility shall…maintain such…equipment and facilities…as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." As PG&E's testimony acknowledges at page 2-9, the Commission's GO 112 adopted in July 1961 also includes requirements for the pressure testing of new pipelines. In short, the obligation to ensure pipeline integrity is not new. Accordingly, I recommend that PG&E's shareholders bear a greater share of PSIP costs than just the 2011 costs which PG&E proposes to absorb.

First, the CPSD has found that, from 1997-2010, PG&E has recovered in rates $39.3 million from ratepayers to cover gas transmission O&M costs that PG&E did not actually spend, as well as $95.4 million in unspent capital costs for its pipeline system.[29] Shareholders benefited from PG&E's failure to use these funds for pipeline maintenance, upgrading, and integrity purposes. Accordingly, PG&E's shareholders should be responsible for 2012-2014 PSIP costs equivalent to these unspent funds, with interest.[30]

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[29] CPUC CPSD "September 9, 2010 Pipeline Rupture in San Bruno, California," released January 12, 2012 (CPSD San Bruno Report), at page 168, CPSD Recommendations 31 and 32.

[30] My rate calculations presented in Tables 4, 5, and 6 do not include interest on these amounts, and are thus too high by the amount of that interest. I have modeled these as reductions to PG&E's direct expenses and capital

Second, since PG&E has been tasked with pipeline integrity since at least 1961, it should have maintained reasonable records. In the aftermath of San Bruno, ample evidence has emerged of the substantial shortcomings of PG&E's pipeline record-keeping and of the utility's lack of an adequate safety culture to ensure the safe operation of its pipeline system:

- The NTSB report on San Bruno includes findings that PG&E's pipeline integrity management program, which should have ensured the safety of the system, was deficient and ineffective because the PG&E program
  - Was based on incomplete and inaccurate pipeline information.
  - Did not consider the design and materials contribution to the risk of a pipeline failure.
  - Failed to consider the presence of previously identified welded seam cracks as part of its risk assessment.
  - Resulted in the selection of an examination method that could not detect welded seam defects.
  - Led to internal assessments of the program that were superficial and resulted in no improvements.[31]

- The CPUC's Independent Review Panel report on San Bruno makes the following findings, among others:
  - PG&E's risk management for pipeline safety has been inadequate given the extremely high percentage of older transmission pipeline miles located in high consequence areas in PG&E's service territory.
  - Pipeline system safety was not substantively tracked, benchmarked, or otherwise a center of focus for the management. There was no evidence of any intent to compromise public safety, but there is the lack of management focus on how system integrity would be managed and assured that has significant consequences.
  - PG&E provided erroneous data because of a lack of: (1) robust data and document information management systems to archive historical data, and (2) processes to capture emerging information about the underground gas transmission system. There is a lack of coordination between field resources and engineering management regarding which data are to be collected and where and how records are to be preserved.

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additions, using the PG&E results of operations (RO) model for 2012-2014.

[31] 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," released August 30, 2011 (NTSB Report), available at http://www.ntsb.gov/investigations/summary/PAR1101.html .

- The lack of an overarching effort to centralize diffuse sources of data hinders the collection, quality assurance and analysis of data to characterize threats to pipelines as well as to assess the risk posed by the threats on the likelihood of a pipeline's failure and consequences.[32]

Given these shortcomings, I recommend that shareholders bear the full costs of PG&E's proposed program to adequately characterize its existing gas transmission pipelines and to modernize its record-keeping for that system. "Traceable, verifiable, and complete" pipeline records, in the words of the NTSB, clearly are fundamental to the safe operation of gas pipelines and to an effective and cost-efficient pipeline integrity management program. As stated in the findings of both the NTSB and the IRP, PG&E clearly has not maintained its records in a manner that is capable of supporting a safe pipeline system. Ratepayers should not bear the costs of bringing PG&E's pipeline records for its existing system up to the point where the utility can support a state-of-the-art gas pipeline safety program that will meet current state and federal safety standards. Shareholders should bear the full $107.1 million in direct expenses in 2012-2014 of PG&E's proposed MAOP validation effort required to validate and modernize PG&E's records for the key variables associated with its gas transmission pipelines.

Third, as PG&E's testimony notes at page 2-9, the Commission's GO 112 adopted in July 1961 included requirements for the pressure testing of new pipelines. As a result, PG&E was required to pressure test pipelines beginning in July 1961, not when the federal standards took effect in 1970. PG&E has proposed that shareholders bear the cost of testing and MAOP validation for post-1970s pipelines for which testing records are not available. However, given CPUC Code Section 451 and GO 112, PG&E shareholders should pay not just for the strength testing of post-1970 pipelines for which the utility has no records (to which PG&E has agreed), but also for the strength testing of 1961-1969 pipelines for which PG&E lacks the original pressure testing records. PG&E indicates that the costs of this strength testing 1960's-vitange pipelines for which records do not exist comprise about $40 million of its Phase 1 implementation plan expenses.[33] I have assigned an additional $40 million in direct expenses to shareholders,

[32] *See* IRP Report, at 5 and 7-8..

[33] PG&E response to NCIP Data Request 004-Q01, included in **Attachment RTB-2**. PG&E estimates the

spread pro-rata based on PG&E's proposed expenses over the 2012-2014 period.

Finally, the Commission should reduce, at least temporarily, PG&E's return on equity for the Phase 1 PSIP investments in its pipeline program. Enhancing pipeline safety will require an unprecedented level of new investment over a short period of time. This should not be a mechanism to provide enhanced short-term shareholder returns, particularly given PG&E's past failings and the immediate major impacts which PSIP spending will have on ratepayers. As a result, I recommend that the Commission reduce PG&E's return on equity on its PSIP capital expenditures by 500 basis points (i.e. by 5%) during the initial three years (2012-2014) of PG&E's pipeline enhancement program. This would reduce PG&E's return on equity on these investments to approximately PG&E's cost of debt. I calculate that this recommendation would reduce the revenue requirements for PG&E's plan by a total of about $67.7 million over 2012-2014.[34] After this period is complete, if there are no safety incidents, the Commission can consider increasing PG&E's return on equity and at that time determine the appropriate amount of, and the timing for, this increase.

Q: What is your rationale for recommending a reduction in PG&E's rate of return?

A: There are two important policy reasons that support this reduction in PG&E's return. First, given the deficiencies in PG&E's pipeline safety program documented in the NTSB and IRP Reports, PG&E needs to work diligently and efficiently to improve pipeline safety and to implement the full scope of its pipeline modernization plan on schedule and on budget. As PG&E has proposed in its plan, ratepayers bear 100% of the risks that the utility will not be able to accomplish the scope of work presented in the plan in the time frame and at the costs it has proposed. PG&E has committed to a set budget for Phase 1 of its plan, a budget that can only be increased after a CPUC review of a PG&E request, but the utility has not committed that it will be able to accomplish the full scope of work proposed in its plan under this budget. As PG&E states at page 1-18 of its testimony:

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cost of testing these 1961-1969 pipelines to be $32 to $48 million; I have used the mid-point of this range.

[34] Based on the use of a 6.35% return on equity in PG&E's RO model. This revenue requirement reduction also includes the $95.4 million reduction in PSIP capital expenditures that I have recommended above.

> …if circumstances lead to a change in Phase 1 project scope, schedule or cost that would cause the program to exceed the Phase 1 forecast for expense or capital, PG&E would be required to submit an advice letter to the CPUC requesting a change in the project forecast. The public and interested parties would have an opportunity to comment on such a request. If the Commission decides not to modify the forecast in response to a request, PG&E would be required to manage and prioritize the remaining work scope within the approved forecast, **potentially resulting in a shift of some projects to Phase 2 of the program**. *(emphasis added)*[35]

Combined with my earlier recommendation to require PG&E to seek Commission authorization for Phase 1 scope changes (or to complete the full scope of Phase 1 after 2014 at shareholder expense if Phase 1 projects slip past 2014), I strongly believe that PG&E needs a continuing financial incentive to ensure that it effectively and efficiently implements its plan in a timely fashion. This is the goal of my proposed temporarily-reduced return on equity for Phase 1 capital investments.

Second, the Commission should recognize that ratepayers are being asked to assume an extraordinary burden, over a very short period of time, to bring the safety of the state's pipeline system up to a reasonable standard, after what appears to be years of under-investment in safety and an ineffective pipeline integrity program. The present value impact on current ratepayers of the large operating expenses and capital investments required in a short period of time under the PG&E plan is significantly higher than if the expenses and investments were implemented at a much more measured pace, over a much longer period of time, as might be characterized by a more consistent and pro-active approach to safety. For example, a simple calculation of the net present value of the 40-year revenue requirements for the capital investments of the PG&E plan is 19% higher than if the same investments were made over a 15-year period instead of a 3-year time frame.[36] The net present value to ratepayers of the 15-year investment plan is equivalent to the proposed 3-year plan with a return on equity reduced to 1% for the first three years. In sum, the impact of the need to put the PG&E implementation plan into place in a short period of time thus imposes a cost premium on

[35] PG&E has further explained its cost recovery proposal, and compared it to its Gas Accord V cost recovery provisions, in its response to NCIP Data Request 003-Q03, included in **Attachment RTB-2**.

[36] These calculations are in **Attachment RTB-3**.

ratepayers, compared to a consistent, long-term effort to improve pipeline safety. In this light, I submit that its proposed temporary reduction of 500 basis points in PG&E's return on equity in its PSIP investments is reasonable.

Q: Are you aware of other circumstances in which the Commission has adopted a temporarily-reduced return on equity for poor utility performance?

A: Yes. In D. 82-12-055, the Commission's decision in Southern California Edison's (SCE) 1983 GRC, the Commission imposed a 10 basis point reduction in SCE's return on equity over its entire rate base for two years as a result of SCE's failure to comply with CPUC policies that required electric utilities to pay QFs prices based on full avoided costs.[37]

IV. THE IMPORTANCE OF MINIMIZING IMPACTS OF SERVICE DISRUPTIONS

Q: What efforts does PG&E intend to undertake to minimize service disruptions?

A: PG&E acknowledges that "[t]his magnitude of pipeline modernization work requires extensive customer and community outreach to notify and educate affected customers of any work that may impact them and address any concerns they may have."[38] PG&E's longstanding Rule 14.A also provides generally as follows:

> PG&E may, in the exercise of reasonable judgment, reduce receipts or deliveries of natural gas in order to test, alter, modify, enlarge, or repair any part of the PG&E system or any facility or property related to the operation of the PG&E system. In all such cases, PG&E shall give Customers reasonable notice as circumstances will permit, and PG&E shall complete such repairs or improvements as soon as practicable and with minimal inconvenience to Customers.

Q: Are these assurances sufficient to mitigate the operational and financial impacts on customers of the service disruptions that may result from implementation plan work?

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[37] D. 82-12-055, mimeo at 133-142.

[38] PG&E Testimony, at pages 3-52 to 3-53.

A: No. Even service reductions or disruptions that take place over the weekend will still have financial and operational impacts on customers. It can prevent customers from using firm transportation rights. Service disruptions can also impair the ability of noncore customers to meet contractual obligations to deliver electricity or other energy-intensive products, or cause such customers to incur higher operating costs. These risks for customers will be increased significantly given the scope of the work on PG&E's pipeline system proposed in the PSIP.

Q: What can PG&E do to mitigate these operational and economic impacts?

A: PG&E can provide its customers with at least 30 days' notice of pipeline enhancement activities that may result in pressure reductions or minor service reductions or disruptions. If PG&E were to need to curtail service completely to a large transmission-level noncore customer who operates critical energy infrastructure such as a refinery or a large electric generator, PG&E should provide much lengthier notice – six months at a minimum. Such customers require this length of notice in order to safely wind down or change operations. PG&E also should provide credits to customers who are unable to use their backbone transportation rights or whose local transmission service is reduced unexpectedly as a result of pipeline safety work.

Q: Has PG&E, in the past, provided service credits to customers whose service has been disrupted?

A: Yes, since June 2011, PG&E has provided firm backbone transportation customers with credits to their reservation charges when customers have been unable to utilize their full firm capacity due to a pressure reduction or other related work. PG&E offered backbone reservation charge credits to impacted customers based on nominations cut due to reduced pipeline capacity. PG&E states that it has not made a determination as to whether or for what time period it will continue to offer backbone reservation charge credits to customers.[39] Under the Gas Accord V revenue-sharing structure, such credits are funded 50% by shareholders.[40]

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[39] PG&E response to NCIP Data Request 002-Q04, included in **Attachment RTB-2**.

[40] Under the Section 10.1.1.1 of the Gas Accord V settlement, as approved in D. 11-04-031, ratepayers and

Q: Should PG&E continue providing this type of reservation charge credit to customers when their backbone service is disrupted by pipeline safety enhancement work?

A: Yes, PG&E should continue to offer such credits at least through the 2012-2014 Phase 1 of the PG&E PSIP. Customers should not have to pay reservation charges for capacity which PG&E cannot make available to customers as a result of its implementation plan. As such credits are funded 50% by shareholders, this will provide PG&E with an incentive to minimize backbone service disruptions.

Q: Should PG&E also compensate a noncore customer if PG&E reduces the local transmission service available to that customer without providing adequate notice to the customer?

A: Yes. I recommend that the model for these rate credits should be the Service Interruption Credit (SIC) that has been a feature of SoCalGas' Rule 23.K for the last 20 years. The SIC provides as follows:

> **Rule 23.K. Service Interruption Credit**
>
> A qualifying service interruption of firm intrastate transmission service is defined as any curtailment which is not (1) the result of either force majeure or scheduled maintenance, as described below, or (2) a curtailment of Standby Procurement service. If a firm intrastate transmission customer experiences more than one qualifying interruption during the ten-year period beginning on the implementation date of the CPUC's Capacity Brokering Rules, the Utility shall provide such customer with a Service Interruption Credit (SIC) of $0.25 per therm of gas curtailed or diverted.

Attachment RTB-4 provides the full details of the SoCalGas SIC. In essence, the SIC represents a financial incentive for SoCalGas to meet its stated reliability standard for firm transportation service of one day of interruptions every ten years. The SIC does not apply to curtailments that result from scheduled maintenance for which the customer has been given at least 30 days' prior notice. SoCalGas' maximum exposure to SIC costs is $5 million per year, and SIC credits are pro-rated if they total more than $5 million in

shareholders will share 50%/50% in any revenue shortfalls from PG&E's backbone service.

any year.

Q: How would you modify the SIC for the circumstances of PG&E's implementation plan?

A: I recommend that the Commission direct PG&E to offer to noncore customers, at shareholder expense, a local transmission interruption credit (LTIC) with the following characteristics:

- The LTIC should apply to reductions in the noncore customer's nominated local transmission service due to pipeline integrity work (under either the PSIP or the GA V TIMP) for which the customer has not received at least 30 days' prior notice from PG&E for minor disruptions or pressure reductions, or 6 months' notice for complete curtailments of large transmission-level noncore customers.
- The dollar magnitude of the LTIC should be equal to the reduction in the noncore customer's nominated local transmission volumes times $0.25 per therm (i.e. $2.50 per Dth). The LTIC credit of $0.25 per therm is chosen both to provide PG&E with a consequential incentive and to recognize that unexpected reductions in natural gas service can result in significant additional costs to a noncore customer's operations.
- Due to the nature and potential cost of service reductions or interruptions to large users, and PG&E's ability to avoid such costs through adequate notice to affected customers, I would recommend that there be no cap on the amount of LTIC credits due to shippers.

Q: Does this complete your prepared direct testimony?

A: Yes, it does.

Attachment RTB-1

Qualifications and Experience of
R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar powerplants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

   - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

   - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

   - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

   - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

   - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

   - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    • *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    • *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    • *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    • *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

    - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

    - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the New Mexico Independent Power Producers, (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Standby rates for net-metered solar customers, and the cost-effectiveness of net metering.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment RTB-2

PG&E Responses to Selected Data Requests

PACIFIC GAS AND ELECTRIC COMPANY
GAS PIPELINE SAFETY OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	NCIP_001-10		
PG&E File Name:	GasPipelineSafetyOIR_DR_NCIP_001-Q10		
Request Date:	November 18, 2011	Requester DR No.:	001
Date Sent:	December 6, 2011	Requesting Party:	Northern California Indicated Producers
PG&E Witness:	Todd Hogenson	Requester:	Tom Beach

QUESTION 10

PG&E states at page 3-38 that its "Pipeline Program work plan specifically excludes work that was authorized by Gas Accord V." Please confirm that the pipeline modernization plan excludes work authorized by Gas Accord V, for the following projects:

a. PG&E indicates that it plans to replace about 21.4 miles of pipeline on Line 109, in the section from milepost 0.49 to 45.84. (See WP 3-2, Lines 22 to 26, and supporting project descriptions). The Gas Accord V included an ILI upgrade project for Line 109 (MP 0.00 to 43.47). Please confirm that the Pipeline Modernization Program work on Line 109 does not overlap with the work approved in GA V. Please also confirm that the work authorized in GAV (i.e. making L-109 piggable) is still needed if the work outlined in the Pipeline Modernization Program goes forward.

b. Line 108 at MP 38.1, replacement of 16" pipe with 24" pipe.

c. Line 118, at MP 5.62 to 12.55, installation of 24" pipe.

d. Line 131, at MP 42.35 to 57.47, replacement of 1.7 miles of 1944-vintage 24" pipe. MWC-75 included a project to replace 22,363 feet (i.e. 4.2 miles) of pipeline within MP 46.34 to 50.57 (see WP 6-44 of PG&E's 2011 GT&S rate case updated workpapers).

e. Line 132, at MP 31.9 to 38.4, upgrading of 7.48 miles of 24-36" pipeline to ensure an in-line inspection tool can pass through the pipeline. The 2011 GT&S rate case workpapers, at WP 6-80, described a L-132 project, at MP 0.00 to 32.93, which included replacement 2,138 feet of 34" pipe to "make the section piggable."

f. Line 300B, PG&E plans to hydrotest 12.35 miles of pipeline between MP 148.9 and MP 283.14. (See WP 3-998). PG&E's 2011 GT&S workpapers (at WP 6-86) described a project to "make piggable" Line 300B, from MP 256.64 to 299.00. Do these projects overlap (i.e. are both needed?) for the section from MP 256.64 to MP 283.14?

ANSWER 10

a. The proposed replacement of 21.4 miles of L-109 within the PSEP is in addition to the "L-109 MP 0.00-43.47 ILI Upgrade" project identified within the GAV, WP 6-81. Both projects are required and there is no overlap in project scope. However, The PSEP Valve Automation Program has expedited the replacement of five L-109 mainline gas valves and this will partially reduce the scope of the L-109 ILI Upgrade Project.

b. The proposed replacement of 6.7 miles of L-108 within the PSEP (WP 3-58 through WP 3-66) is in addition to the two L-108 pipeline replacement projects proposed within GAV on WP 6-48, "L-108 MP 38.00-40.27 Inst 24", and WP 6-52, "L-108 MP 61.66-63.5 Inst 9700' 24". There is no project overlap.

c. The proposed replacement of 6.87 miles of L-118 within in PSEP (WP 3-101) does include a portion of L-118 that was originally proposed for replacement in PG&E's 2011 GT&S Rate Case. However, the project of "L-118 - 9.5 Miles of 24 inch Capacity" was specifically excluded from GAV. (see Gas Accord Settlement Agreement dated August 20, 2010, Page 6, section 7.2.5), and therefore was not funded by GAV. The PSEP decision tree analysis identified many of the pipe segments of L-118 for replacement. PG&E proposes to install 24" diameter pipe to address pipeline safety, reliability and capacity.

d. The proposed replacement of 1.7 miles of L-131 within PSEP (WP 3-122) is in addition to the 22,363' replacement of "L-131 MP 46.34 to 50.57 Replc Fremont," GAV WP 6-44. There is no project overlap. PSEP is proposing to replace L-131 between MP 32.38 and 35.87, WP 3-125.

e. PSEP proposed to retrofit for ILI L-132 between MP 31.9 and 38.4, WP 3-563. GAV included a project to retrofit L-132 for ILI retrofit from MP 0.00 to 32.93, GAV WP 6-80. The ending milepoint identified in the GAV project was a forecast. The actual ending milepoint is 31.9. These are separate projects.

f. PSEP proposes to hydrotest 21.67 miles of L-300A between MP 230.32 – 490.59, (WP 3-985). The specific pipe segments by MP are noted on WP 3-987 and WP 3-988. Nine pipe segments are located within the GAV project to retrofit L-300A for ILI from MP 256.21 – 299.01, GAV WP 6-91. The pipeline ILI modifications funded by GAV were completed this year. These are separate projects and they both are needed. The CPUC directive ordered PG&E to strength test all untested pipelines. The ILI retrofits are being driven by both CPUC and DOT Pipeline Integrity Regulations mandating baseline pipeline integrity assessments.

PACIFIC GAS AND ELECTRIC COMPANY
GAS PIPELINE SAFETY OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	NCIP_003-03		
PG&E File Name:	GasPipelineSafetyOIR_DR_NCIP_003-Q03		
Request Date:	December 22, 2011	Requester DR No.:	003
Date Sent:	January 10, 2012	Requesting Party:	Northern California Indicated Producers
PG&E Witness:	Todd Hogenson	Requester:	Tom Beach

QUESTION 3

This question follows-up Q10 of NCIP's First Data Request. PG&E's response to Q10 – for example, part (e) -- indicates that PG&E can have two adjacent pipeline replacement projects on the same line, one funded by GAV and another by PSEP. Please respond to the following questions:

a. GAV set a budget for pipeline safety and integrity work for the 2011-2014 period. It is NCIP's understanding that PG&E retained the ability to decide which pipeline safety and integrity projects to undertake during the GAV period, subject to the one-way balancing account provided in GA V. Please explain in detail how PG&E will distinguish between GAV and PSEP projects, and GAV vs. PSEP spending on pipeline safety and integrity work. For example, could PG&E classify the retrofit for ILI on L-132 between MP 31.9 and 38.4 as a GAV project (and thus to be applied against the one-way GAV balancing account), instead of PSEP? What safeguards exist to make certain that this re-classification will not occur?

b. Please compare and contrast PG&E's ratemaking proposal for PSEP, as stated on pages 1-18 and 1-19 of PG&E's testimony, to the one-way balancing account for these costs used in GAV.

ANSWER 3

a. In compliance with Decision 11-04-031 in PG&E's 2011 GT&S Rate Case, which approved the Gas Accord V Settlement Agreement, Ordering Paragraph (OP) 5 of that decision directs PG&E to prepare, on a semi-annual basis, a "Gas Transmission and Storage Safety Report" (Safety Report) containing information provided in Appendix C of the decision.

   In OP 6 of Decision 11-04-031, the Commission directed the CPSD to review the Safety Report, establish procedures to monitor PG&E's storage and pipeline related activities set forth in the reports, assess whether the projects PG&E identified in the proceeding are at risk of not being carried out, and to track whether PG&E is spending its allocated funds on storage and pipeline related safety, reliability, and integrity activities.

PG&E's first Safety Report, covering the period from January 1 – June 30, 2011, was field with the CPUC on September 30, 2011. This report included a complete list of every Gas Transmission & Storage project (capital and expense), Major Work Category (MWC), Project Order Number, project description, status, expenditures incurred, and whether the project was described in any Rate Case Workpaper and year. These Safety Reports will provide the CPUC and other interested parties' transparency into PG&E's actual project expenditures. PG&E created new MWCs and Planning Orders for the Pipeline Safety Enhancement Plan (PSEP), which ensures PSEP and GT&S projects will not be comingled.

b. In Gas Accord V a one-way balancing account was specifically established to track the aggregate amount of integrity management expense during the term of the settlement. Any unspent accumulated balance (as compared to the approved forecast) at the end of the Settlement Period, plus interest, will be returned to customers. In Gas Accord V there are no one-way balancing accounts for other type costs.

In PSEP, PG&E's ratemaking proposal for the expense costs is similar to Gas Accord V. PG&E proposes the expense forecast be approved for the four year period. PG&E proposes to recover in rates its forecast of annual expense and that the forecast would be tracked in a balancing account and trued-up to reflect the actual incurred expenses each year as part of PG&E's Annual Gas True-up Advice Letter. As with the Gas Accord V one-way balancing account, this approach ensures that PG&E will only recover in rates its actual costs. Any authorized expense amounts not spent would be returned to customers, with interest, at the end of Phase 1. If circumstances lead to a change in Phase 1 scope, schedule or cost that would cause the program to exceed the Phase 1 forecast for expense, PG&E would submit an advice letter to the CPUC requesting a change in the forecast, with the public to have an opportunity to comment. If the Commission decides to not modify the request, PG&E would then manage and prioritize the remaining work scope within the approved forecast, potentially resulting in a shift of some projects to Phase 2.

For capital expenditures, PG&E also proposes the capital forecast to be approved for the four year period. In addition, PG&E propose to recover the capital costs of a project in rates only after that project has been placed into operation. As discussed (in more detail) with the expense forecasts, if circumstances cause the capital costs to increase above the approved forecast, PG&E would be required to submit an advice letter to the Commission requesting approval for a change in the forecast. If not approved by the Commission, PG&E would manage and prioritize the remaining work scope within the approved forecast, potentially shifting some project work into Phase 2.

Similar to the reporting procedures approved in Gas Accord V (Decision 11-04-031), PG&E proposes reporting requirements in the PSEP to make progress of the Phase 1 work transparent to the Commission and public.

PACIFIC GAS AND ELECTRIC COMPANY
GAS PIPELINE SAFETY OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	NCIP_003-04		
PG&E File Name:	GasPipelineSafetyOIR_DR_NCIP_003-Q04		
Request Date:	December 22, 2011	Requester DR No.:	003
Date Sent:	January 10, 2012	Requesting Party:	Northern California Indicated Producers
PG&E Responder:	Jennifer Mordini	Requester:	Tom Beach

QUESTION 4

NCIP is concerned that significant numbers of PG&E personnel that plan, oversee, and administer pipeline safety and integrity work will now be working on both GAV and PSEP projects. Prior to the San Bruno incident, R. 11-02-019, and PG&E's PSEP, NCIP expects that these PG&E employees would have worked 100% on GAV projects, with 100% funding from GAV rates. Please explain how PG&E segregates employee time between GAV and PSEP work, such that the costs spent in each area are properly assigned and accounted for.

ANSWER 4

In 2011, new Provider Cost Centers (PCC) in PG&E's SAP accounting system were created to house employees who are dedicated to the PSEP. Segregating these employees into separate cost centers ensures that their costs are charged only to PSEP work.

Individual contributor employees such as physical bargaining unit and general construction, technical staff such as engineering, estimating, mapping, survey, project management, and construction management direct charge their time to specific orders and projects through timecards. This ensures employees costs are charged directly to the project(s) they are working on, whether it be a GAV or PSEP project.

Management personnel not included in the above mentioned PSEP PCCs have their costs captured in the calculated standard rate of chargeable employees within their organization. Therefore, if their organization supports billable PSEP work, the cost of management employees is transferred to PSEP projects via the standard rate of time charging employees.

Members of the Business Finance organization (who do not sit in the PSEP specific PCCs mentioned above) typically do not charge out their time, but instead it is spread via a supervision and management cascade to the Line of Business that they support. However, Business Finance personnel who are supporting PSEP have been charging their time to the PSEP program, thus ensuring that it is not cascaded to GAV funded work and that it is captured as a cost of the PSEP program.

All GAV work that was contemplated as part of the GAV settlement will continue as planned. The PSEP does not alter the work that PG&E had planned for 2011-2014 as part of Gas Accord V.

QUESTION 5:

We understand that SoCalGas/SDG&E classify portions of their pipeline systems as High Consequence Areas (HCAs) pursuant to 49 CFR, Part 192, Subpart O. For all of the HCA miles on the SoCalGas/SDG&E systems, please provide data on the number of miles for which the primary type of buildings or sites within the Potential Impact Radius are (1) primarily residential, (2) primarily commercial, or (3) primarily industrial.

RESPONSE 5:

As discussed during the conference call on November 30, 2011, SoCalGas and SDG&E do not have readily available data responsive to this request. Per agreement reached on November 30, 2011, SoCalGas and SDG&E provide the following data that is available regarding the types of structures located within PIRs of HCAs:

Building % found within PIR of HCA		
Building Type	**SoCal Gas**	**SDG&E**
Single Family Residence / Townhouse	78%	73%
Duplex, Triplex, Quadplex	5%	3%
Apartment	4%	8%
Condominium	3%	6%
Commercial	7%	8%
Industrial	2%	1%
Utilities	<1%	<1%
Agricultural	<1%	<1%
Amusement-Recreation	<1%	<1%
Hospital (medical complex, clinic)	<1%	<1%
Commercial w/ Residential	<1%	<1%

QUESTION 6:

Please provide an estimate of the number of SoCalGas and SDG&E customers, by rate group, that are located within the Potential Impact Radius in the HCAs on the SoCalGas /SDG&E transmission pipeline systems.

RESPONSE 6:

As explained during the call on November 30, structures located within the PIR of a pipeline segment located in an HCA may or may not receive natural gas service from SoCalGas or SDG&E. As further explained during the conference call on November 30, 2011, SoCalGas and SDG&E do not have readily available data responsive to this request. Per agreement reached on November 30, 2011, SoCalGas and SDG&E provide data that is available regarding the types of structures located within PIRs of HCAs in Response 5 above.

Typical transportation rate(s) by types of building are provided in the table below. The rate group is identified first, followed by the possible tariff schedules they may apply (i.e. GR, G-CARE, etc). These tariffs are listed under: SoCalGas: http://socalgas.com/regulatory/tariffs/tariffs-rates.shtml and SDG&E: http://sdge.com/rates-regulations/current-and-effective-tariffs/current-and-effective-tariffs.

Typical Transportation Rate Tariff Serving Buildings found within PIR of HCA		
Building Type	**SoCal Gas**	**SDG&E**
Single Family Residence / Townhouse	Residential GR,G-CARE	Residential GR, G-CARE
Duplex, Triplex, Quadplex	Residential GR, GS, GM, G-CARE	Residential GR, G-CARE, GM, GS
Apartment	Residential GR, GS, GM, G-CARE	Residential GR, G-CARE, GM, GS

Typical Transportation Rate Tariff Serving Buildings found within PIR of HCA		
Building Type	**SoCal Gas**	**SDG&E**
Condominium	Residential GR, GS, GM, G-CARE	Residential GR, G-CARE, GM, GS
Commercial	Core C&I G-10	Core C&I GN-3,GTNC
Industrial	NonCore C&I GT-F, GT-I, GT-TLS	NonCore C&I GN-3,GTNC
Utilities	Wholesale or Electric Generation G-10, GT-F, GT-I, GT-TLS	Electric Generation GN-3, GTNC, EG, TLS
Agricultural	Core C&I or Gas Engine or NonCore C&I G-10 GT-F, GT-I G-EN	Core C&I or NonCore C&I GN-3, GT-NC
Amusement-Recreation	Core or NonCore C&I G-10, GT-F, GT-I	Core or NonCore C&I GN-3, GT-NC
Hospital (medical complex, clinic)	Core or NonCore C&I G-10, GT-F, GT-I,	Core or NonCore C&I GN-3, GT-NC

PACIFIC GAS AND ELECTRIC COMPANY
GAS PIPELINE SAFETY OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	NCIP_003-01		
PG&E File Name:	GasPipelineSafetyOIR_DR_NCIP_003-Q01		
Request Date:	December 22, 2011	Requester DR No.:	003
Date Sent:	January 10, 2012	Requesting Party:	Northern California Indicated Producers
PG&E Witness:	Todd Hogenson	Requester:	Tom Beach

QUESTION 1

This question follows-up Q8 and Q9 of NCIP's First Data Request. PG&E's responses to these questions indicate that the utility does not have the requested information. The same questions were asked of SoCalGas-SDG&E, which provided data on the types of buildings within the Potential Impact Radius of the transmission pipelines on its system, as well as an indication of the rate schedules under which the utility typically serves such building types. See attached response. In light of SoCalGas-SDG&E's ability to provide responsive information to the same requests, NCIP asks PG&E to re-consider whether it has information responsive to these requests.

ANSWER 1

PG&E does not have the requested information.

PG&E's High Consequence Area (HCA) identification process relies primarily on a foot by foot visual review, within the Company's geographic information system (GIS), of the pipeline alignment and the potential impact circles around the pipeline in conjunction with aerial photography, parcel data and care facility data. For HCAs, the results of the identification process document if the reviewer observes where there are a minimum of 20 habitable structures, or an identified site or both. The reviewer does not write down the actual number of structures within the HCA or whether the structures viewed are residential, commercial or industrial.

PACIFIC GAS AND ELECTRIC COMPANY
GAS PIPELINE SAFETY OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	NCIP_004-01		
PG&E File Name:	GasPipelineSafetyOIR_DR_NCIP_004-Q01		
Request Date:	January 5, 2011	Requester DR No.:	004
Date Sent:	January 19, 2012	Requesting Party:	Northern California Indicated Producers
PG&E Witness:	Todd Hogenson	Requester:	Tom Beach

QUESTION 1

PG&E has proposed that shareholders will bear the costs of strength testing for post-1970s pipelines (PG&E Testimony, at pp. 8-10, lines 8-14). The December 23, 2011 report of the Jacobs Consultancy for the CPUC's Consumer Protection and Safety Branch (Jacobs/CPSD Report) recommends at page 9 (Recommendation 5.4.2) that, for transmission pipe installed between 1961 and 1970 and for which PG&E lacks pressure-test data, utility shareholders should bear the costs for this testing. Please provide data on the costs (expenses and capital for each year from 2012-2014) that PG&E's Implementation Plan proposes to expend for the strength testing of transmission pipe operating at or above 20% of its SMYS and installed between 1961 and 1970 for which PG&E lacks pressure-test data.

ANSWER 1

On January 13, 2011, PG&E responded to the CPUC concerning Jacobs Consultancy recommendation 5.4.2. PG&E supports this recommendation for pressure testing conducted as part of Phase 1 of the Pipeline Safety Enhancement Plan (PSEP), with clarification on pressure testing documentation requirements under General Order (GO) 112, effective July 1, 1961.

MAOP Records validation and the development of pipeline features lists (PFL) for HCA pipe segments is nearly complete; however, the majority of PFL development for non-HCA pipe is scheduled for Phase 3 PFL Build (to date, only small amounts of non-HCA PFL has been completed) and will not be complete until 2013 (as shown in Table 6-2 of Chapter 6) so PG&E's mileage figures provided below are preliminary and subject to change.

For gas transmission pipelines operating above 20% Specified Minimum Yield Strength (SMYS) installed between 7/1/61 and 12/31/70, PG&E has identified 37.0 miles of pipe segments that may have incomplete pressure test documentation that are scheduled to be pressure tested in PSEP Phase 1, from 2011-2014. Approximately 4.6 miles were hydrotested in 2011 (at shareholder expense) and an additional 32.4 miles of pipe are scheduled to be pressure tested between 2012 and 2014. These 32.4 miles of pipe segments are located within 69 separate PSEP expense strength testing projects (Chapter 3 Workpapers, Table 3, page 3-753) so it would extremely difficult to quantify expense cost for each segment, or portion of a project, by year, given variability in project costs and the percentage of a strength testing project with pipe segments meeting these criteria. A preliminary, rough estimate for strength testing 32.4 miles of pipe segments could range from $32 to $48 million, based on a range of strength testing costs between $1 million/mile and $1.48 million/mile (PG&E's actual 2011 hydrotesting costs).

PACIFIC GAS AND ELECTRIC COMPANY
GAS PIPELINE SAFETY OIR
Rulemaking 11-02-019
Data Response

PG&E Data Request No.:	NCIP_002-04		
PG&E File Name:	GasPipelineSafetyOIR_DR_NCIP_002-Q04		
Request Date:	December 16, 2011	Requester DR No.:	002
Date Sent:	December 30, 2011	Requesting Party:	Northern California Indicated Producers
PG&E Witness: PG&E Responder:	Trista Berkovitz Prateek Chakravarty Roger Graham	Requester:	Seema Srinivasan

QUESTION 4

On page 3-34, lines 31-33, PG&E states that it "*will make reasonable efforts to schedule and sequence work in order to maintain customer service and minimize customer impact (outages).*"

4.1. Please list all efforts PG&E plans to undertake to minimize service disruptions.

4.2. Does PG&E intend to provide a rate credit to those customers who are unable to use transportation rights as a result of pipeline safety-related service disruptions?

4.2.1. If yes, please explain where the funds for such a credit will come from.

4.2.2. If no, please explain why not.

4.3. Has PG&E ever provided a credit to customers following an operational curtailment? If so, please clarify when and explain the circumstances under which a credit was or is provided.

4.4. In this proceeding, the Commission has ordered PG&E to reduce its maximum allowable operating pressure on several pipelines. Has PG&E provided credits to any customers or taken other efforts to compensate customers where they were unable to use firm capacity as a result of these pressure reductions? If yes, please clarify the nature of compensation provided. If no, please explain why not.

ANSWER 4

4.1 PG&E makes every reasonable effort to avoid customer outages when performing work on the gas system. These efforts include scheduling the outage to avoid customer impacts, performing critical work that could impact customer service during the evenings or weekends, developing operating strategies to avoid outages including opening valves, or adjusting system pressures within allowable margins to maintain service, and utilizing portable natural gas to supply systems or individual customers.

4.2 No.

4.2.1. N/A.

4.2.2. Under PG&E's CPUC-approved tariff, Gas Rule 14 (Capacity Allocation and Constraint of Natural Gas Service), PG&E does not guarantee continuity of service or sufficiency of quantity, and is therefore not required to provide credits to customers.

PG&E has not determined if credits will be offered to firm backbone transportation customers if such customers are impacted by work performed under the Pipeline Safety Enhancement Plan. If any credits are offered by PG&E, PG&E will determine at that time how to fund the credits.

4.3 To date, PG&E has not provided a reservation charge credit to customers following an operational curtailment.

4.4 Since June 2011, as conditions have warranted and as a result of CPUC-mandated pressure reductions, PG&E has elected to provide firm backbone transportation customers with a credit to reservation charges when a pressure reduction or other related work made it impossible for customers to utilize their full firm capacity. PG&E has not made a determination as to whether or for what time period it will continue to offer reservation charge credits to customers.

Reservation charge credits were offered to impacted customers based on nominations cut due to reduced pipeline capacity.

Attachment RTB-3

Ratepayer Impact of 3-years *versus*
15-years of Capital Investments

Ratepayer Impact of 3 years versus 15 years of Capital Investments

Taxes	
FIT	35.0%
SIT	8.8%

Capital Structure			
Debt	48%	6.0%	2.9%
Equity	52%	11.4%	5.9%
WACC			8.8%

Inflation:	3%

Depreciation:	40 years
	2.5% per year

CASE 1: **$1.32 biillion in Investments in 3 years, 1% RoE for first three years**

RoE for years	1.0%

	Total Investment	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Investment (BOY)	1,322	384	480	500														
Depreciation		10	22	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Rate Base		375	833	1,299	1,265	1,231	1,197	1,163	1,129	1,094	1,060	1,026	992	958	924	890	856	822
Return on Equity		2	4	7	75	73	71	69	67	65	63	61	59	57	55	53	51	48
Interest		11	24	37	36	35	34	33	33	32	31	30	29	28	27	26	25	24
Property Taxes @ 1%		4	8	13	13	12	12	12	11	11	11	10	10	10	9	9	9	8
SIT Taxable Income		-13	-28	-44	26	25	24	24	23	22	21	21	20	19	19	18	17	17
SIT		-1	-2	-4	2	2	2	2	2	2	2	2	2	2	2	2	2	1
FIT Taxable Income		-11	-26	-40	23	23	22	21	21	20	20	19	18	18	17	16	16	15
FIT		-4	-9	-14	8	8	8	8	7	7	7	7	6	6	6	6	6	5
Total Taxes		-1	-11	-18	10	10	10	10	9	9	9	8	8	8	8	7	7	7
Revenue Requirement		11	17	26	122	118	115	112	108	105	102	99	95	92	89	85	82	79
NPV (40-year)	805																	

CASE 2: **$1.32 biillion in Investments over 15 years, 11.4% RoE for all years**

	Total Investment	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Investment (BOY)	1,322	91	94	96	99	102	105	108	112	115	118	122	126	129	133	137		
Depreciation		2	5	7	9	12	15	17	20	23	26	29	32	35	39	42	42	42
Rate Base		89	177	267	356	447	537	628	720	811	904	997	1,090	1,184	1,279	1,374	1,332	1,289
Return on Equity		5	10	16	21	26	32	37	42	48	53	59	64	70	75	81	79	76
Interest		3	5	8	10	13	15	18	21	23	26	29	31	34	37	40	38	37
Property Taxes @ 1%		1	2	3	4	4	5	6	7	8	9	10	11	12	13	14	13	13
SIT Taxable Income		2	4	5	7	9	11	13	15	16	18	20	22	24	26	28	27	26
SIT		0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	2	2
FIT Taxable Income		2	3	5	7	8	10	12	13	15	17	18	20	22	24	25	25	24
FIT		1	1	2	2	3	3	4	5	5	6	6	7	8	8	9	9	8
Total Taxes		2	3	5	6	8	10	11	13	15	16	18	20	22	23	25	24	24
Revenue Requirement		9	19	28	38	47	57	67	76	86	96	106	116	126	136	146	141	137
NPV (40-year)	805																	
Net-to-gross		1.80																

CASE 1:

	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
Investment (BOY)																			
Depreciation	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Rate Base	787	753	719	685	651	617	583	549	515	480	446	412	378	344	310	276	242	208	173
Return on Equity	**46**	**44**	**42**	**40**	**38**	**36**	**34**	**32**	**30**	**28**	**26**	**24**	**22**	**20**	**18**	**16**	**14**	**12**	**10**
Interest	**23**	**22**	**21**	**20**	**19**	**18**	**17**	**16**	**15**	**14**	**13**	**12**	**11**	**10**	**9**	**8**	**7**	**6**	**5**
Property Taxes @ 1%	**8**	**8**	**7**	**7**	**7**	**6**	**6**	**5**	**5**	**5**	**4**	**4**	**4**	**3**	**3**	**3**	**2**	**2**	**2**
SIT Taxable Income	16	15	15	14	13	12	12	11	10	10	9	8	8	7	6	6	5	4	4
SIT	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**	**0**
FIT Taxable Income	15	14	13	13	12	11	11	10	9	9	8	8	7	6	6	5	4	4	3
FIT	**5**	**5**	**5**	**4**	**4**	**4**	**4**	**4**	**3**	**3**	**3**	**3**	**2**	**2**	**2**	**2**	**2**	**1**	**1**
Total Taxes	**6**	**6**	**6**	**6**	**5**	**5**	**5**	**5**	**4**	**4**	**4**	**3**	**3**	**3**	**3**	**2**	**2**	**2**	**1**
Revenue Requirement	**76**	**72**	**69**	**66**	**63**	**59**	**56**	**53**	**49**	**46**	**43**	**40**	**36**	**33**	**30**	**26**	**23**	**20**	**17**
NPV (40-year)																			

CASE 2:

	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
Investment (BOY)																			
Depreciation	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
Rate Base	1,247	1,205	1,163	1,121	1,078	1,036	994	952	910	867	825	783	741	699	656	614	572	530	488
Return on Equity	**74**	**71**	**69**	**66**	**64**	**61**	**59**	**56**	**54**	**51**	**49**	**46**	**44**	**41**	**39**	**36**	**34**	**31**	**29**
Interest	**36**	**35**	**33**	**32**	**31**	**30**	**29**	**27**	**26**	**25**	**24**	**23**	**21**	**20**	**19**	**18**	**16**	**15**	**14**
Property Taxes @ 1%	**12**	**12**	**12**	**11**	**11**	**10**	**10**	**10**	**9**	**9**	**8**	**8**	**7**	**7**	**7**	**6**	**6**	**5**	**5**
SIT Taxable Income	25	24	24	23	22	21	20	19	18	18	17	16	15	14	13	12	12	11	10
SIT	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
FIT Taxable Income	23	22	21	21	20	19	18	18	17	16	15	14	14	13	12	11	11	10	9
FIT	**8**	**8**	**8**	**7**	**7**	**7**	**6**	**6**	**6**	**6**	**5**	**5**	**5**	**5**	**4**	**4**	**4**	**3**	**3**
Total Taxes	**23**	**22**	**21**	**20**	**20**	**19**	**18**	**17**	**17**	**16**	**15**	**14**	**14**	**13**	**12**	**11**	**10**	**10**	**9**
Revenue Requirement	**132**	**128**	**123**	**119**	**114**	**110**	**105**	**101**	**96**	**92**	**88**	**83**	**79**	**74**	**70**	**65**	**61**	**56**	**52**
NPV (40-year)																			

Net-to-gross

CASE 1:

	37	38	39	40
Investment (BOY)				
Depreciation	34	34	34	34
Rate Base	139	105	71	37
Return on Equity	**8**	**6**	**4**	**2**
Interest	**4**	**3**	**2**	**1**
Property Taxes @ 1%	**1**	**1**	**1**	**0**
SIT Taxable Income	3	2	1	1
SIT	**0**	**0**	**0**	**0**
FIT Taxable Income	3	2	1	1
FIT	**1**	**1**	**0**	**0**
Total Taxes	**1**	**1**	**1**	**0**
Revenue Requirement	**13**	**10**	**7**	**4**
NPV (40-year)				

CASE 2:

	37	38	39	40
Investment (BOY)				
Depreciation	42	42	42	42
Rate Base	445	403	361	319
Return on Equity	**26**	**24**	**21**	**19**
Interest	**13**	**12**	**10**	**9**
Property Taxes @ 1%	**4**	**4**	**4**	**3**
SIT Taxable Income	9	8	7	6
SIT	**1**	**1**	**1**	**1**
FIT Taxable Income	8	7	7	6
FIT	**3**	**3**	**2**	**2**
Total Taxes	**8**	**7**	**7**	**6**
Revenue Requirement	**47**	**43**	**38**	**34**
NPV (40-year)				

Net-to-gross

Attachment RTB-4

SoCalGas Rule 23.K.
Service Interruption Credit

J. Curtailment Violations (Continued) T

3. Authorized Curtailment Quantity (Continued)

The customer's total authorized curtailment quantity for the applicable period of curtailment shall be equal to the sum of the authorized curtailment quantities for each of the customer's services which are not subject to curtailment during such period. For each such service, the authorized curtailment quantity shall be equal to the monthly contract quantity divided by the customer's actual number of operating days for such service during the month in which the curtailment occurs, multiplied by the customer's actual number of operating days during the curtailment period.

The customer's actual operating days for the month shall be determined based on the operating-day information set forth in the customer's contract. For service designated as operating seven days per week, the operating days shall be all calendar days in the month. For service designated as less than seven operating days per week, the operating days shall be all designated days in the month excluding national holidays. Customers with non-uniform operating schedules for any particular month shall be required to designate in the contract the actual operating-day schedule for such months. The customer may request a change to the operating schedule on a month-to-month basis. All operating schedules shall be subject to the Utility's acceptance and the Utility may adjust such schedules as it deems necessary based on the customer's operations.

K. Service Interruption Credit T

A qualifying service interruption of firm intrastate transmission service is defined as any curtailment which is not (1) the result of either force majeure or scheduled maintenance, as described below, or (2) a curtailment of Standby Procurement service. If a firm intrastate transmission customer experiences more than one qualifying interruption during the ten-year period beginning on the implementation date of the CPUC's Capacity Brokering Rules, the Utility shall provide such customer with a Service Interruption Credit (SIC) of $0.25 per therm of gas curtailed or diverted.

For the customer's first qualifying interruption during the ten-year period, the SIC shall only apply to the volume of curtailed or diverted gas over and above 72 consecutive hours of full curtailment or the volumetric equivalent thereof during a five day period. For subsequent qualifying interruptions during this period, the SIC shall apply to all of the customer's curtailed or diverted volumes resulting from the subsequent interruptions regardless of the duration or extent of the customer's initial interruption.

(Continued)

(Continued)

K. Service Interruption Credit (Continued) T

The maximum aggregate SIC obligation of the Utility in any calendar year shall be $5 million. To the extent such maximum aggregate obligation would be exceeded, the Utility shall provide the SIC on a pro rata basis to all applicable customers for the calendar year. Utility shall make payment of the SIC at the end of the applicable calendar year.

1. Force Majeure

For the purpose of SIC applicability, force majeure shall be defined as the occurrence of unforeseen events or conditions, not resulting from a negligent act or omission on the part of the Utility, that are beyond its reasonable control and that could not have been prevented by the exercise of due diligence on its part. The Utility shall use all reasonable efforts to remedy such events or conditions and to remove the cause of same in an adequate manner and with reasonable dispatch. The occurrence of high demand for gas service due to weather conditions shall not constitute a force majeure event.

2. Scheduled Maintenance

For the purpose of SIC applicability, scheduled maintenance shall be considered the interruption of transmission service to the customer resulting from maintenance of the Utility's facilities which are directly relevant to providing such service to the customer's facilities when the customer has been given at least thirty (30) calendar days prior written notice of the scheduled date of the maintenance and service interruption.

The Utility shall take all reasonable steps to minimize the duration of such scheduled maintenance interruptions and to reroute the flow of natural gas to eliminate any service interruptions that would otherwise occur due to such maintenance.

The Utility shall consult with the customer in scheduling any such maintenance interruptions and shall use reasonable efforts to schedule such maintenance to accommodate the customer's operating needs and to continue same only for such time as is necessary, including any agreed upon adjustments to the scheduled date for maintenance as reasonably necessary in light of unforeseen occurrences affecting the customer and/or the Utility.