ORA Attachments

ATTACHMENT A

ORA EXHIBIT 20 IN A.13-12-012

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Decision 14-06-007 June 12, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for Authority To Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding	Application 11-11-002 (Filed November 1, 2011)

DECISION IMPLEMENTING A SAFETY ENHANCEMENT PLAN AND APPROVAL PROCESS FOR SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY; DENYING THE PROPOSED COST ALLOCATION FOR SAFETY ENHANCEMENT COSTS; AND ADOPTING A RATEMAKING SETTLEMENT

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1. Summary

1.1. Executive Summary

This decision addresses three issues: first it adopts a plan for pipeline Safety Enhancement, although it also finds that the proposed budget is too rudimentary to preapprove. However, we want the applicants to implement Safety Enhancement now. Therefore, we adopt the concepts embodied in the Decision Tree and authorize a Safety Enhancement Capital Cost Balancing Account and a Safety Enhancement Expense Balancing Account for San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) to record the costs incurred, subject to refund, after a reasonableness review. SDG&E and SoCalGas may file annually after December 31, 2015 for a reasonableness review of the completed projects recorded in the Phase 1 Safety Enhancement Capital Cost Balancing Account and annually for the expenses recorded in the Phase 1 Safety Enhancement Expense Balancing Account. SDG&E and SoCalGas may alternatively file for preapproval of specific projects seeking approval of a cap or for other specific guidance. These applications need detailed management, engineering, and accounting records to justify recovery of reasonable costs in rates. Second, this decision, in compliance with our settlement rules, adopts a reasonable all-party settlement for SDG&E and SoCalGas' Triennial Cost Allocation proceeding, which is a cost allocation, marginal cost, and rate design proceeding commonly referred to as a "phase 2" general rate case. Third, this decision rejects a specific cost allocation modification proposed to allocate the costs of Safety Enhancement based on human exposure to risk rather than the cost of providing service to all customer classes. The following decision discusses these issues in the above order.

1.2. Decision Overview

This decision finds that San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) have presented a reasonable, albeit conceptual plan to enhance the safety of their natural gas pipeline system (Safety Enhancement). The forecast costs include capital expenditures of $229 million for SDG&E and $1.2 billion for SoCalGas, and annual operating costs of $7 million for SDG&E and $255 million for SoCalGas. In this decision, we adopt a process to recover the Costs of Safety Enhancement by creating new balancing accounts which allow the companies to begin work and recover their costs subject to refund.[1] SDG&E) and SoCalGas) may file annually after December 31, 2015 for reasonableness review of the completed projects recorded in the Phase 1 Safety Enhancement Capital Cost Balancing Account and annually for the expenses recorded in the Phase 1 Safety Enhancement Expense Balancing Account. SDG&E and SoCalGas may alternatively file for preapproval of specific projects seeking approval of a cap or for other specific guidance. These applications need project specific management, engineering, and cost records that demonstrate the reasonableness of cost recovery of the detailed implementation plan as executed by the Companies.

[1] To be clear, the refund would be to adjust to balance in the account to reflect the outcome of a reasonableness review. If, hypothetically, $1,000 is recorded and the reasonableness review finds only $900 was prudently and reasonably incurred, the $100 difference would be removed from the account.

SDG&E and SoCalGas failed to maintain construction records or data for portions of the pipelines that would demonstrate the proper testing of these pipelines to the standards that the Commission has determined to be necessary in Decision 11-06-017. Although many of these pipelines operated for many years without failure, we can no longer assume or presume them to be safe. Because these pipelines can no longer be presumed to be safe, they can no longer be presumed to be used and useful to provide service to customers unless tested or replaced. Ratepayers should not pay twice to have a properly installed system in place, therefore, the cost of such tests for facilities installed after July 1, 1961, must be absorbed by the shareholders of SDG&E and SoCalGas in situations where the company has failed to maintain records of strength testing required at the time of installation of the pipeline.

Whenever SDG&E or SoCalGas cannot produce a record of a pressure test required at the time of installation of the pipeline and whenever the existing systems cannot be properly tested and proven to be safe, or for other reasons it is determined they should be replaced, then we will treat the remaining book value of these existing systems as abandoned plant and allocate those costs to the shareholders of SDG&E and SoCalGas. The ratepayers must however pay for the cost of the new system; the ratepayers clearly benefit by receiving a brand-new system, which will be safe, and which will safely serve them for decades.

The record developed in the proceeding showed that SDG&E and SoCalGas had, at the time[2], over 385 miles of pipeline segments which would

[2] SDG&E and SoCalGas indicate in their comments that they have since recovered some of these records.

require pressure testing or replacement because documentation could not be found that those segments sufficiently met modern requirements or did not demonstrate that at the time of construction, the pipeline segments were properly strength tested in compliance with industry best practices or mandatory regulations in place at the time of installation to support their ongoing safety operations.[3] The record also shows that SoCalGas has 23 miles of pipeline which has not been pressure tested through a static strength test, but the company has lowered this pipeline's pressure to a level at which, the company states, the pre-reduction pressure provides for a "pressure-carrying" equivalent of 125% of Maximum Allowable Operating Pressure.

We cannot estimate the true magnitude of either the testing or replacement costs or the impact on either ratepayers or shareholders at this time. Although ratepayers will bear the costs of the new and safer pipeline systems as installed, we cannot reasonably forecast and preapprove Safety Enhancement costs at this time because SDG&E and SoCalGas do not have reliable detailed cost estimates, nor can we adequately estimate the cost for testing pipelines or the remaining book value of abandoned pipelines that will be absorbed by the shareholders. This must be resolved later.

We cannot quantify the change in the degree or level of safety achieved by these anticipated projects as a part of Safety Enhancement. There is simply no metric for potential lives to be saved, avoidance of personal injury, avoidance of property loss or damages, or disruptions to the economy that would result if the

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[3] *See* the Decision Tree: Where the pipeline is operated in a class 3 or 4 location or high Consequence Area and not documented for pressure testing to 1.25 times Maximum Allowable Operating Pressure.

unmodified pipeline system remained in service as is. What we do know is that the system will be built to the best current practices, that there will be proper permanent documentation of the construction, and that the company will continue to operate the systems in a safe and reliable fashion with the capacity to do inspections and tests that may not be possible to perform on the current system.

This proceeding is closed.

2. Application Background

San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (collectively Applicants or SDG&E and SoCalGas) filed the required Triennial Cost Allocation Proceeding (Cost Allocation). In Rulemaking (R.) 11-02-019, the assigned Commissioner ruled that this Cost Allocation proceeding for both Applicants would be the most logical proceeding for the SDG&E and SoCalGas reasonableness and ratemaking review of the companies' Safety Enhancement Plans (Safety Enhancement) because this proceeding deals with all cost allocation and rate design. Therefore, Safety Enhancement was reassigned here to take advantage of the evidentiary record and policy decisions emerging on rate design and cost allocation. (*See* Ruling dated December 21, 2011.)

The Commission opened R.11-02-019 to review and establish a new model of natural gas pipeline safety regulation for California. Decision (D.) 11-06-017 ordered all California natural gas transmission pipeline operators to prepare Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans (Implementation Plans) to either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test. The Commission required that the Implementation Plans provide for testing or replacing all such pipelines as soon as practicable, and that at the completion of the implementation period, all California natural gas transmission pipeline segments would be (1) pressure tested, (2) have traceable, verifiable, and complete records readily available, and (3) where warranted, be capable of accommodating in-line inspection devices. In addition, the Commission required the operators to implement interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions, prioritization of pressure testing for critical pipelines that must run at or near Maximum Allowable Operating Pressure values which result in hoop stress levels at or above 30% Specified Minimum Yield Stress, and other such measures that will enhance public safety during the implementation period.

On December 2, 2011, SDG&E and SoCalGas filed their Safety Enhancement plans[4] in the rulemaking. Safety Enhancement, if adopted as filed, provides for hundreds of millions of dollars in annual investment over more than a decade beginning with capital forecasts for Phase 1A of $1.2 billion for SoCalGas and $229 million for SDG&E and operating and maintenance forecasts for Phase 1A of $255 million for SoCalGas and $7 million for SDG&E. SDG&E and SoCalGas also seek to include a Phase 1B. In Phase 1B, SoCalGas and SDG&E propose to abandon and replace all pre-1946 non-piggable transmission pipelines segments remaining in the system after the completion of Phase 1A. It

[4] The term "Pipeline Safety Enhancement Plan" is the personalized name used by both Applicants in their compliance filings for the "Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans" ordered in D.11-06-017 and we will use Applicants' name, contracted to Safety Enhancement, hereafter, unless specifically citing to the filing original requirement.

originally included new construction too, to maintain service by SoCalGas and SoCalGas.[5] Safety Enhancement also includes proposals to non-destructively examine, in lieu of testing, pipeline segments of 1,000 feet or less.

In addition to the testing or replacing pipeline, Safety Enhancement includes modifications of 541 valves, and the addition of 20 valves, to provide for automated shut-off capability in order to isolate, limit the flow of gas to no more than 30 minutes, and thereby facilitate timely access of "first responders" into the area surrounding a substantial section of ruptured pipe. Safety Enhancement also includes: 1) improvements to communications and data gathering to ascertain pipeline conditions; 2) installing backflow valves to prevent gas from flowing into sections intended to be isolated from other connected lines; 3) expand the coverage of SDG&E and SoCalGas' private radio networks to serve as back-up to other available means of communications with the newly installed valves to improve system reliability; 4) installing remote leak detection equipment; and 5) increasing physical patrols and leak survey activities.

Pursuant to Pub. Util. Code § 451, each public utility in California must "furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities, . . . as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." Ensuring that the management of investor-owned gas utility systems fully performs its duty of safe operations is a top priority of this Commission,

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[5] SoCalGas and SDG&E Opening Brief at 191.

and the California Legislature has recently confirmed this critical function of the Commission.[6]

As set forth in D.11-06-017,[7] the Commission found that 1970 federal and 1961 California regulations for gas pipeline safety established requirements for the pressure testing natural gas transmission pipeline facilities; however, these applied only to new pipeline facilities and exempted all pre-existing in-service pipeline from the pressure test requirement. Accordingly, all pipelines installed after those dates are expected to be pressure tested, with the result that some of the oldest in-service natural gas pipeline has not been subjected to post-construction pressure testing to determine its Maximum Allowable Operating Pressure. Instead, the Maximum Allowable Operating Pressure for these untested pipeline segments is set by the highest recorded operating pressure on that segment during a defined time period.[8] Consequently, the operational records for the exempted pipeline segments are critical to determining their Maximum Allowable Operating Pressure.

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[6] Pub. Util. Code § 963(b)(3) finds 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. 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.

[7] The Commission's General Order 112, which became effective on July 1, 1961, mandated pressure test requirements for new transmission pipelines (operating at 20% or more of Specified Minimum Yield Strength installed in California after the effective date. Similar federal regulations followed in 1970, but exempted pipeline installed prior to that time from the pressure test requirement. Such pipeline is often referred to as "grandfathered" pipeline, because pursuant to 49 CFR §192. 619(c), pressure testing was not mandated.

[8] 49CFR §192.619(c).

After review of the detailed record in R.11-02-019 and before the National Transportation Safety Board regarding the records and vintage pipeline, the Commission concluded that the historic exemption and the utilities' record-keeping deficiencies had resulted in circumstances inconsistent with the safety, health, comfort, and convenience of utility patrons, employees, and the public. The Commission ordered all natural gas transmission pipelines in service in California to be brought into compliance with modern standards for safety, and that all California natural system operators file and serve a proposed Implementation Plan to comply with the requirement that all in-service natural gas transmission pipelines in California have been pressure tested in accord with 49 CFR Part 192 §§ 192.505 and 192.507 excluding reliance solely on § 192.619(c).

The Commission required that the Implementation Plans include interim safety enhancement measures, and that the analytical focus be a list of all transmission pipeline segments that have not been previously pressure tested, with pipeline that must run at or near operating pressures that result in hoop stress levels at or above 30% of Specified Minimum Yield Strength to receive prioritized designations for replacement or pressure testing. The Commission required the operators to also give high priority to pipeline segments located in Class 3 and Class 4 locations and High Consequence Area pipelines in Class 1 and 2 locations, with pipeline segments in other locations given lower priority for pressure testing.[9] The operators were required to set forth the criteria on

[9] The Pipeline and Hazardous Materials Safety Administration regulations define the four class locations by number of human-occupied buildings located within 220 yards of the pipeline: Class 1, 10 or fewer buildings; Class 2, 10 to 45 buildings; Class 3, 46 or more buildings, or with a place of public assembly; and, Class 4, where buildings with four or more stories are prevalent. (49 CFR § 192.5.)

which pipeline segments were identified for replacement instead of pressure testing.

The Commission also required each operator to include in the Implementation Plan a priority-ranked schedule for pressure testing all pipeline not previously so tested, and to provide for pressure reductions where necessary. The Implementation Plan also must address retrofitting pipeline to allow for in-line inspection tools and the installation of, where appropriate, automated or remote-controlled shut-off valves in order to limit the flow of gas from a large breach or rupture to a pipeline segment located in a Class 3 and Class 4 locations and HCAs in Class 1 and 2 locations. The Commission, when adopting PG&E's safety enhancement plan in D.12-12-030, has already clearly articulated its philosophy and policy that natural gas pipelines must be made to be safe and reliable. We adhere here to that same commitment.[10]

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[10] Among all public utility facilities, natural gas transmission and distribution pipelines present the greatest public safety challenges. Unlike more common public utility facilities, gas pipelines carry flammable gas under pressure - in transmission lines, often at high pressure - and these pipelines are typically located in public right-of-ways, at times in densely populated areas. The dimensions of the threat to public safety from natural gas pipeline systems, including the pace at which death and life-altering injuries can occur, are far more extreme than other public utility systems. This unique feature requires that natural gas system operators and this Commission assume a different perspective when considering natural gas system operations. This perspective must include a planning horizon commensurate with that of the pipelines; that is, in perpetuity, as well as an immediate awareness of the extreme public safety consequences of neglecting safe system construction and operation.

In the context of an unending obligation to ensure safety, we must also realize that in practical terms safety is exacting, detailed, and repetitive. It is also expensive, so ensuring that high value safety improvements are prioritized and obtaining efficiencies wherever possible is also essential. And, in the end, if the goal of safe operations is met, the reward is that absolutely nothing bad happens. In short, safety is difficult, expensive and seemingly without reward. (D.12-12-030 at 43.)

While emphasizing the importance and need to make these safety improvements in California's natural gas transmission systems, the Commission also stressed that it will closely scrutinize the costs to be imposed on ratepayers. In D.11-06-017, the Commission required that the Implementation Plans explicitly analyze cost and demonstrate that the proposed expenditures obtain the greatest safety value for ratepayers. The Commission stated its commitment to ensuring that California's working families and businesses pay only for necessary safety improvements, and the Commission encouraged customers to participate in the process for reviewing the Implementation Plans.

3. Burden and Standard of Proof, and Record

3.1. Overview

Pursuant to Pub. Util. Code § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified." (§ 454.) The Commission requires that the public utility demonstrate with admissible evidence that the costs it seeks to include in revenue requirement are reasonable and prudent. The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable.

SDG&E and SoCalGas must meet the burden of proving that they are entitled to the relief sought in this proceeding, and SDG&E and SoCalGas have the burden of affirmatively establishing the reasonableness of all aspects of the application.[11]

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[11] *See* generally Application of Southern California Edison Company for Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2009,

Footnote continued on next page

With the burden of proof placed on SDG&E and SoCalGas, the Commission has held that the standard of proof SDG&E and SoCalGas must meet is that of a preponderance of evidence.[12] Preponderance of the evidence usually is defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth'"[13] In short; SDG&E and SoCalGas must present more evidence that supports the requested result than would support an alternative outcome.

We have analyzed the record in this proceeding within these parameters. These are the same parameter used for Pacific Gas & Electric Company (PG&E). (D.12-12-030 at 41.)

3.2. Application of Standard

It is thus quite clear that SDG&E and SoCalGas bear the burden of proof for the reasonableness of its past practices in building, maintaining, and operating the pipeline systems and for its ratesetting proposals in this proceeding. Parties have debated what standard to apply: clear and convincing or preponderance, a lower standard. The Commission's standard for reasonableness issues is the preponderance standard, and we find that at even the lower standard of preponderance of evidence, SDG&E and SoCalGas failed

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And to Reflect That Increase In Rates (D.09-03-025, *mimeo*. at 8) (March 12, 2009) and Decisions cited therein.

[12] *See* D. 12-12-030, at 44. "Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering."

[13] In the Matter of the Application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, D.08-12-058, *citing* Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184.

to have adequate and reliable records for significant segments of their system and must therefore bear some of the consequences that result from those inadequate records. We further find that SDG&E and SoCalGas's showing was inadequate in detail and thoroughness to approve Safety Enhancement as proposed thus failing the usual preponderance test. This has been one of the main challenges in this proceeding. Therefore, as discussed below, we will require further showing before approving any final cost recovery from the balancing accounts.

3.3. Record

The record for this proceeding consists of the documents filed and served and the testimony and exhibits admitted during the evidentiary hearings. This record is the sole basis for this decision.

4. SDG&E & SoCalGas' Safety Enhancement

4.1. Decision Tree

SDG&E and SoCalGas produced two exhibits, the first of which is a "Decision Tree" included here as Attachment I,[14] and a more complicated table that reconciled all the natural gas pipeline system into various classifications or risk factors, age, documentation, etc., referred to as a "Reconciliation" included here as Attachment II.[15]

The Decision Tree results in a first cut allocation of SDG&E and SoCalGas's pipelines into the proposed phases 1A, 1B, and Phase 2. It is the heart of SDG&E and SoCalGas's Safety Enhancement process.

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[14] Ex. SCG-33-R.

[15] Ex. SCG-34-R.

The Decision Tree and Reconciliation are works in progress, showing the first steps taken by SDG&E and SoCalGas to define the scope of work for Safety Enhancement. SDG&E and SoCalGas began by categorizing the existing system's condition and risk. Phase 1A is the first most critical grouping of pipeline facilities which need to be addressed. SDG&E and SoCalGas also proposed a Phase 1B.

In its January 17, 2012 Technical Report on SDG&E and SoCalGas's Pipeline Safety Enhancement Plan, the Commission's Safety and Enforcement Division (Safety Div.), then Consumer Protection and Safety Division, discussed its review of SDG&E and SoCalGas's Safety Enhancement process, including its Decision Tree (in an earlier form to the Decision Tree in Attachment I). The Safety Div. report stated: "The use of a documented pressure test of (125% of Maximum Allowable Operating Pressure) at the start of the … decision tree process, is a conservative, first cut, approach…" and that as shown by research, "…it can provide some level of assurance as to the stability of the longitudinal seams on a pipeline." The Safety Div. report went on to find that: "Overall, the … decision tree process for prioritization in Phase 1A, and the sub-prioritization process included therein, appears to result in reasonably prioritized segments."

In regard to automated valves, the Safety Div. report found that SDG&E and SoCalGas "…have used a sound approach towards determining where automated valves should be installed in order to reduce the consequences of a major breach. This approach appropriately considers pipeline diameter, the operating stress on the line, and geological threats as part of the determination process." Essentially, the Safety Div. found that the companies' proposal to use remote controlled valves to isolate (generally purged of gas) an 8-mile segment of pipeline of any diameter, within 15 minutes of the last valve necessary for isolation being closed, as reasonable. However, Safety Div. did recommend that fewer automated valves, instead of remote controlled valves included in Safety Enhancement, would provide similar protection, albeit with a slight increase in risk of gas loss due to false closures.

4.1.1. Decisions Made Under the Decision Tree

The Decision Tree starts with 3,885 total miles: 245 for SDG&E, and 3,630 for SoCalGas. By the end of the process it has allocated those miles into a variety of sub-categories: for immediate replacement; or testing and possible replacement; inspection and then either replacement or left in service; or those for which there is no further action. In fact the largest grouping of pipeline of 3,305 miles, falls into Boxes 8 and 9, no further action category, and only 385 miles fall into the most complex categories where they are Class 3 or 4 Locations, or High Consequence Areas, and not documented as ever having been strength tested to a level of 125% of Maximum Allowable Operating Pressure.

Some parties argue that Phase 1B should be considered later after the most critical portions of the system are resolved in Phase 1A. If we have learned one institutional lesson it would be that we need to look at safety generally, and Safety Enhancement in particular, as an integrated and ongoing commitment and that it is not a couple of quick fixes. Therefore, we approve the Decision Tree as it embodies the decision making processes for SDG&E and SoCalGas. The reasonableness review that we order should allow parties to address any concerns regarding Phase 1B. For example, whether every segment needs to be replaced or its safety concerns could be addressed in some other manner.

As noted, the Decision Tree is a management process, which is also a work in progress. For example, SDG&E and SoCalGas removed from Phase 1 their proposal to construct a new 36-inch line, Line 3602. (Exhibit SCG-22 at 7-8.) This and all other new construction must be addressed in either new applications for those projects or in the new application for Phase 2.

4.2. Positions of the Parties

4.2.1. Office of Ratepayer Advocates - Summary

The Office of Ratepayer Advocates[16] (ORA) argues that for the years 2012 through 2015, SDG&E and SoCalGas ask the Commission to order ratepayer funding of a total of approximately $1.7 billion in capital expenditures and Operations and Maintenance expenses for direct costs only; excluding carrying costs such as taxes, depreciation, rate of return or other costs necessary to support the investment. Even using this incomplete estimate, ORA is gravely concerned that this would be a 10% rate hike. (Opening Brief at 1.) Further, ORA notes the Commission has stated its "… primary efforts have been focused on ensuring that California's natural gas transmission system operators are properly calculating the Maximum Allowable Operating Pressure for each segment of the natural gas pipeline transmission system." (Citing to D.12-04-021, at 1.) ORA points out the Commission has ordered utilities to prepare Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans. According to , SDG&E and SoCalGas,the companies need $12 billion worth of revenue requirements to assure the Commission that it is properly calculating the Maximum Allowable Operating Pressure for its gas transmission system. In DRA's opinion "if that is indeed true, then something is

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16 Like Safety Div., ORA had a name-change during this proceeding. The exhibits in the record introduced by ORA are labeled with the old acronym "DRA" and therefore those citations will use "DRA" whereas we will use ORA for the entity in this decision.

very wrong here. Either the Sempra utilities' gas transmission system is in a terrible state of disrepair, or the utilities are using the opportunity to pad shareholder returns by proposing capital improvement projects that are well beyond the primary directive of the Commission. Clearly, Sempra's ratepayers should not be forced to pay for the remedial or excessive improvements Sempra proposes." (DRA Opening Brief at 2.)

ORA proposes that for the years 2012 through 2015:

- the Commission authorize ratepayer funding of no more than $69.75 million for the combined utilities (Ex. DRA-5 at 20);
- SDG&E and SoCalGas should pay for all pressure testing of natural gas transmission lines installed since 1935. If SDG&E and SoCalGas chooses to replace, rather than test, pipelines installed after 1935, the companies should bear the costs, and the Commission should adopt a rate of return adjustment for those replacement pipelines (DRA Opening Brief at 4);
- does not oppose ratepayer funding of hydrotesting costs for 12 miles of transmission pipeline installed prior to 1935, but not at the excessive cost level SDG&E and SoCalGas proposes (DRA Ex. 2 at 78);
- does not oppose ratepayer funding of some valve upgrade work, but recommends SDG&E and SoCalGas's $122 million request be reduced to $52 million for the years 2012-2015 (Ex. DRA-4 at 9); and
- opposes all of SDG&E and SoCalGas's other attempts to impose system enhancement costs on ratepayers. Specifically, inclusion of costs for testing or replacing segments of distribution pipelines and non-criteria miles of transmission pipelines, for "mitigation" of pre-1946 construction methods, and for system enhancement projects like methane detectors, fiber optic cables, information technology programs (Ex. DRA-2, at 29-42.)

4.2.2. Discussion

Because we adopt a balancing account approach to redress the inadequate budgets offered by SDG&E and SoCalGas, we need not address ORA's immediate concerns about forecasts; in fact we take a more conservative approach and we will use balancing accounts and reasonableness reviews. As discussed throughout, we are very concerned about costs imposed on ratepayers and we endeavor to strike a fair balance between ratepayers and shareholders. All of ORA's issues should be addressed in the reasonableness review for the balancing accounts.

4.2.3. The Utility Reform Network's (TURN) Summary

TURN was an active participant on Safety Enhancement and has raised some serious concerns in its Opening Brief as summarized below. Essentially TURN is concerned that SDG&E and SoCalGas has not provided a detailed well budgeted plan and that the Commission should not authorize rate recovery based on the level of detail in our record. TURN goes on to criticize, as vague and incomplete proposals, SDG&E and SoCalGas's specific requests for shut-off valves, and other related systems as a part of Safety Enhancement.

a) SDG&E and SoCalGas Safety Enhancement is based on preliminary cost estimates that the utilities themselves did not prepare and it reflects an incomplete analysis of which specific pipelines will be replaced rather than pressure-tested.

b) Under SDG&E and SoCalGas's proposal there would be no reasonableness review of the recorded costs associated with actual pressure tests or pipeline replacements.

c) The Commission should simultaneously begin a subset of pipeline safety programs while ensuring its ability to perform the "comprehensive analysis" called for in D.11-06-017 before approving SDG&E and SoCalGas's proposed estimate of $1.7 billion in direct costs.

d) No recovery of testing or replacement costs in Phase 1 for post-1955 pipe segments should be approved now because these costs would not have been necessary if the SDG&E and SoCalGas Utilities had retained the pressure test records for those segments as directed by applicable standards and regulations. TURN argues these records are necessary to validate the safe operating pressure of transmission pipelines and are therefore critical for public safety. TURN argues California law therefore requires shareholders to absorb all the costs resulting from SDG&E and SoCalGas's violations of these important pipeline safety laws and standards.

e) For those segments with an identified manufacturing threat that are slated for replacement or remediation under Safety Enhancement, SDG&E and SoCalGas should be required to demonstrate that any testing that should have been conducted under federal Integrity Management requirements would not obviate the need to address the segment in here.

f) The Commission should defer action on SDG&E and SoCalGas's proposed Decision Tree (the process summarized in Ex. SCG-33-R and Attachment I) at this time; the ultimate determination of whether to pressure test or replace a line is a key decision for each and every pipeline that is a subject of the plan. TURN argues that the decision tree relies on "promised-but-not-unveiled" criteria that are more in the nature of still-evolving "guidelines that provide direction."

g) The Commission should reject the SDG&E and SoCalGas proposal that the current review of Safety Enhancement can serve as the likely exclusive opportunity for the agency to address the utilities' decision-making process. TURN proposes as a substitute the actual review of the actual decisions rather than the last-minute proposal for an advisory board, etc.

h) The Commission should deny rate recovery for the vast majority of the costs labeled "interim safety enhancement measures," because they are in fact records search costs that should not be included in rates, arguing that recovery would be prohibited retroactive ratemaking, the costs are connected to past utility imprudence, and SDG&E and SoCalGas has failed to demonstrate the reasonableness of the costs.

i) The Commission should promote further exploration and development of in-line inspection technologies; because TURN believes the cost of an in-line inspection is substantially lower than the cost of a pressure test, if the Commission can determine that the results are similarly reliable for purposes of assessing the condition of an existing pipeline segment, the overall cost of the assessment would decline.

j) The Commission should adopt the principle that reliance on automatic shut-off valves is the preferred approach where feasible, and direct the Safety Division and the utilities to work together to reduce the number of remote controlled valves installed and thereby increase the potential cost-effectiveness of this element of Safety Enhancement.

k) The Commission should reject the utilities' proposal to include all pipeline segments designated "accelerated miles," and instead permit the SDG&E and SoCalGas Utilities to propose inclusion of "accelerated miles" on a project-specific basis once they have completed the engineering and planning for each project and seek Commission approval of that project.

l) The Commission should not adopt the SDG&E and SoCalGas proposals for "technology enhancements" due to their failure to present any evidence that the value to customers of the fiber optics and methane detection monitors warrants incurring the cost.

m) The Commission should not adopt the SDG&E and SoCalGas Utilities' proposal for pre-1956 pipeline "mitigation" measures at this time. The utilities have not demonstrated that these construction techniques are jeopardizing the safety of their pipeline systems, yet these measures represent the most expensive single component contained within the Proposed Case.

n) For the Enterprise Asset Management System the Commission should authorize the SDG&E and SoCalGas Utilities to track the related costs in their Pipeline Safety and Reliability Memorandum Accounts, subject to subsequent reasonableness review. In addition to cost-effectiveness and other more traditional reasonableness review issues, SDG&E and SoCalGas would need to demonstrate that the effort is incremental to the effort necessary to meet existing prudent record-keeping standards.

4.2.4. Discussion

Because we adopt a balancing account approach to redress the inadequate budgets offered by SDG&E and SoCalGas we need not address TURN's immediate concerns about forecasts and costs generally; in fact, we take a more conservative approach and we will use balancing accounts and reasonableness reviews. This is a greater protection than TURN's memorandum account proposal. We do discuss below and adopt the elimination of any incentive compensation for management employees. As discussed throughout, we are very concerned about costs imposed on ratepayers and we endeavor to strike a fair balance between ratepayers and shareholders. We do not agree that examining pre-1956 pipelines should be deferred. As discussed in the decision we adopt the intended scope of work as summarized by the Decision Tree instead.

We believe that we have addressed TURN's programmatic concerns with Safety Enhancement even though we authorize more work than TURN recommends; for example, we authorize the Phase 1B work to ensure it is performed in a timely manner. Likewise, by adopting the analytical approach embodied in the Decision Tree we address all pipelines to ensure the system as a whole can be relied upon to be safe, and not just complying with the safety rules of a bygone era.

4.2.5. Southern California Generation Coalition - Summary

The Southern California Generation Coalition (Coalition) in its opening brief argues that the application and testimony lacked the necessary detail needed before the Commission could adequately conduct a review of the proposed expenditures and authorize rate recovery. The Coalition proposed that the Commission should "review on a case-by-case basis" utilizing an existing tool used by this Commission, the Expedited Application Docket procedure, each pipeline segment as a specific project within Safety Enhancement. (Coalition Opening Brief at 1.) As discussed below, we find merit with this concept, which we expand on in our balancing account methodology, but we do not adopt a series of mini-reviews by project or groups of projects. Preapproval would unduly delay Safety Enhancement and relieve SDG&E and SoCalGas of their obligation to exercise expert and prudent management.

4.2.6. Discussion

Safety Enhancement will take years to complete and will encompass numerous individual projects. It is only fair that ratepayers should have the benefit of detailed plans for this Commission to consider before authorizing or preapproving the expenditure of many hundreds of millions of dollars.

As set forth below, we find that SDG&E and SoCalGas have presented an adequate justification for Safety Enhancement at a conceptual level and we approve their Decision Tree (Attachment I) analytical approach. We find, however, that the budgets offered in support of this billion-dollar proposal are not sufficiently detailed to justify ratemaking pre-approval at this time. We authorize SDG&E and SoCalGas to file Tier 2 advice letters to establish balancing accounts and, in time, subsequent applications to demonstrate the reasonableness of costs and recover those costs in rates. We authorize SDG&E and SoCalGas to proceed with Safety Enhancement projects that conform to the Decision Tree logic and track the costs of the work in a series of balancing accounts described below. This decision does not preclude SoCalGas or SDG&E from submitting additional applications for specific projects for further guidance or approval. For example, SDG&E and SoCalGas may prefer to file one or more applications before undertaking specific projects, asking for pre-approval for the related revenue requirement to be included in rates which would be subject to a cap. Or, simply use the balancing accounts authorized in this decision and rely on the reasonableness reviews to authorize subsequent rate recovery.

For the Safety Enhancement Capital Cost Balancing Account SDG&E and SoCalGas may file reasonableness review applications for the recorded balances which reflect completed projects. This might be every other year or whenever there is a large balance. For the Safety Enhancement Expense Balancing Account, SDG&E and SoCalGas may file annually for a reasonableness review of the account balance beginning after December 31, 2015. They may also choose to file less often.

5. Safety Enhancement – Applying Section 454 Standard

5.1. Decision Tree

The Decision Tree is consistent with the priorities we set forth in D.11-06-017 and reflects a reasoned and orderly approach to testing or replacing natural gas pipeline in the SDG&E and SoCalGas systems. We find that SDG&E and SoCalGas have justified this approach to prioritizing the testing and replacement of natural gas pipeline systems. Therefore, we approve the Decision Tree and the analytical processes shown therein.

5.2. Ratemaking Proposal

During the evidentiary hearings SDG&E and SoCalGas produced two exhibits, Decision Tree the Reconciliation which explain and document both the review process (Decision Tree) proposed by SDG&E and SoCalGas and demonstrated in table form that the planning counted for the entire system (Reconciliation). This involved discussion and input from the parties and directions from the Judge. SDG&E and SoCalGas were eventually able to demonstrate that the Decision Tree does constitute a comprehensive plan to fully review and where necessary replace the natural gas system. The Reconciliation, and the time it took for the company to prepare it, illustrates both the complexity of the problem and that neither SDG&E nor SoCalGas, as of serving testimony or the evidentiary hearings, had sufficient management systems and personnel in place to show that they fully understand the flaws and weaknesses in the implementation plan and they do not have a complete plan in place which would result in a safe and reliable natural gas system.

The witness for the applicants clearly demonstrated that the budget preparation performed for this proceeding by SDG&E and SoCalGas is rudimentary at best. The witness contrasted the company's proposal with the budget requirements used by the federal government for major procurement projects. The witness clearly showed that SDG&E and SoCalGas at best a "level 5" budget in a system where a level 5 budget is extremely preliminary, in fact rudimentary, and then only after careful planning and design does the budget progressively improve to levels 4, 3, 2, and finally level 1which is the most complete an advanced level of budgetary planning.[17]

In testimony, SDG&E and SoCalGas admitted:

> The estimates in our workpapers represent best available cost projections considering the nature and extent of projects that needed to be estimated for the PSEP, and the short timeframe available to develop them. SoCalGas and SDG&E acknowledge that these estimates are necessarily preliminary and often somewhat conceptual in nature. (Ex. SCG-21 at 1-2.)

The budget proposals of SDG&E and SoCalGas are clearly not sufficient to justify this Commission to authorize for ratemaking purposes. There are only two clear alternatives: authorize the program but make the companies fully liable for all risk of reasonableness review in an after-the-fact review of the final cost of the project; or require the companies to more fully develop budget proposals on a segment by segment basis for project construction, and seek commission approval based upon the level 1 quality of budgeting.

We therefore find that SDG&E and SoCalGas have not justified their proposed ratemaking for the costs of Safety Enhancement with their current showing. We direct SDG&E and SoCalGas to file new applications, consistent with today's decision, with detailed project descriptions and history and adequate cost records to justify recovery in rates.

5.3. Safety Enhancement Balancing Accounts

A balancing account is an appropriate regulatory tool where the scope of work is known and accepted as is here, Safety Enhancement as described by the

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[17] "Class 5 or slightly better" characterization is based on a "recommended practice" produced by the Association for the Advancement of Cost Engineering.

Decision Tree and elsewhere in testimony by SDG&E and SoCalGas, etc., and we find it to be a sufficient project scope; but there is not a reasonable forecast of cost. A memorandum account is an alternative regulatory tool that would only be appropriate here if we could not find that Safety Enhancement was necessary and defined. Note that SDG&E and SoCalGas already have a memorandum account for Safety Enhancement where we have not found a scope of work to be reasonable nor have we found those costs to be reasonable for rate recovery.

SDG&E and SoCalGas must file Tier 2 Advice Letters to establish two new balancing accounts for each company: a Safety Enhancement Capital Cost Balancing Account and a Safety Enhancement Expense Balancing Account. These accounts will record the revenue requirement for capitalized pipeline and other facilities and the actual expenses for Safety Enhancement that are not capitalized. SDG&E and SoCalGas must follow conventional utility accounting practices and separately record costs normally expensed in the expense-related balancing account and only record in the capital balancing account those Safety Enhancement costs which are typically capitalized as plant in service.[18] The companies have the discretion to file annual cost recovery applications to review the reasonableness of completed capital projects included in the accounts and annual (or multi-year) expenses.

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[18] Further, capitalized costs are those costs, which in a general rate case, are treated as plant in service for rate base purposes; and they are recovered not as a lump sum, but as annualized revenue requirements, over time, following the Commission's well established ratemaking practices. Nothing in the brevity of these descriptions here or elsewhere in the decision is intended to alter conventional and well-established ratemaking practices.

We believe that there is a major concern that we must not only ensure that the cost for these projects are reasonable based upon a competent and thorough analysis and design and budget process, but that also the project itself meets the overarching goal of enhancing the safety and reliability of the pipeline system.

We agree with TURN that SDG&E and SoCalGas's proposals as offered in this proceeding are incomplete and are an inadequate platform for authorizing construction or granting rate relief. We also recognize TURN's point that the Utilities have a financial incentive to favor pipeline replacement over testing, given that the former receives rate base treatment and a rate of return. Our requirement for a reasonableness review will allow parties to examine whether replacement has been favored over less costly but more prudent alternatives.

We are concerned however that TURN singles out pre-1946 pipeline mitigation because it is the most expensive i.e., extensive, component of SDG&E and SoCalGas's proposed mitigations. In fact, we are concerned that it is the oldest pipe, pre-1956, that might lack documentation; might be of the lowest quality of materials or construction, or even maintenance; and is least likely to meet current safety standards and therefore this pipe should be a focus of Safety Enhancement. Because we require SDG&E and SoCalGas to submit detailed records for all work performed for all testing and replacement, TURN's concerns can be addressed in the reasonableness review of the balancing accounts.

We also see no benefit to creating any oversight or advisory board to muddle the clear line of responsibility that rests solely with SDG&E and SoCalGas to competently manage and maintain the pipeline system. TURN is right to be concerned and we will not adopt such a board.

SDG&E and SoCalGas argues that ratepayers must bear all costs of compliance including testing and replacement of pipeline as a result of failing tests or lack of documentation. SDG&E and SoCalGas also asks for preapproval. ORA proposes an ex-post review, i.e., a reasonableness review after work is completed. SDG&E and SoCalGas argue:

> ex post reviews create an incentive for inefficient expenditure on the part of the utility. Rather than devoting resources to implementing an approved plan, the utility will focus on documenting the justification for each expenditure, and when forced to invest, will choose less-efficient systems with low capital costs (but possibly higher operating costs) to hedge the risk that they will not be able to recover the full capital cost of the investment. (SDG&E and SoCalGas Opening Brief at 56.)

We decline to adopt SDG&E and SoCalGas' inadequate cost forecasts and preapprove cost recovery. Instead our use of balancing accounts lets the companies exercise expert professional judgment and begin Safety Enhancement that is necessary to ensure a safe and reliable system.

5.4. Safety Division Oversight

The Commission's Safety Division (Safety Div.) has broad delegated authority to generally enforce the Commission's safety jurisdiction. Specific to SDG&E and SoCalGas's Safety Enhancement we delegate to Safety Div. the specific authority to directly observe and inspect the testing, maintenance and construction, and all other technical aspects of Safety Enhancement to ensure public safety both during the immediate maintenance or construction activity. and to ensure that the pipeline system and related equipment will be able to operate safely and efficiently for their service lives. Safety Div. may issue verbal requests for information which must be promptly answered, although Safety

Div. must subsequently reduce all requests to writing. SDG&E and SoCalGas may not delay responding or wait for the written confirmation.

The Director Safety Div. should be delegated the following specific authority to act in addition to all existing general authority delegated to staff in order to effectively protect the ratepayers and therefore may inspect, inquire, review, examine and participate in all activities of any kind related to Safety Enhancement SDG&E, SoCalGas, all of their contractors shall immediately provide any document, analysis, test result, plan, of any kind related to Safety Enhancement as requested by Safety Div.'s staff or its contractors. Safety Div. must subsequently confirm all requests in written form, however all responses to must be immediate. Safety Div. may issue immediate stop work orders to SDG&E and SoCalGas, and all of their contractors when necessary to protect public safety. SDG&E and SoCalGas must comply immediately. The Director of the Safety Div. is authorized to order SDG&E and SoCalGas to take such action as may be necessary to protect immediate public safety. Specifically, the Director is authorized to issue immediate stop work orders when necessary to immediately protect the public or to ensure public safety in the future from possible errors or flaws in design, testing, maintenance and construction related to Safety Enhancement.

The Safety Div. must file and serve a copy of any stop work order in this proceeding no later than close of business of the Commission's next business day following the issuance of a stop work order. The Commission's Executive Director, and the Chief Administrative Law Judge, together shall ensure that SDG&E and SoCalGas, and all other parties to this proceeding, shall have timely procedural opportunities for a review of any action or stop work orders issued by Safety Div. as may be feasible under the specific circumstances whenever Safety exercises its delegated authority.

6. Ratemaking Principles to be Applied in Reasonableness Applications

6.1. Summary

This decision does not propose or adopt any penalty for SDG&E or SoCalGas. We do however identify certain costs that should be absorbed by shareholders instead of ratepayers. Consistent with long-standing ratemaking principles, ratepayers will generally bear the reasonable costs for a safe and reliable natural gas transmission system. However, where imprudent actions by the gas system operator have led to unreasonable costs, we will assign those costs to shareholders.

6.2. Penalty, Disallowance or Consequences

California law, Commission practice and precedent, and common sense, all essentially require that before ratepayers bear any costs incurred by the utility, that those costs must be just and reasonable. That is, the costs must have been prudently incurred by competent management exercising the best practices of the era, and using well-trained, well-informed and conscientious employees and contractors who are performing their jobs properly. When that occurs, the commission can find the costs incurred by the utility to be just and reasonable and therefore, they can be recovered from ratepayers. When this is not the case however, the Commission can and must disallow those costs: that is unjust or unreasonable costs must not be recovered in rates from ratepayers.

SDG&E and SoCalGas presented an outside witness whose essential theme was that if the companies failed to recover any cost whatsoever this amounted to a penalty. We find this testimony completely unpersuasive and we accord it no weight. SDG&E and SoCalGas's witness would have us believe that any disallowance for unreasonable, imprudent costs, i.e., a regulatory disallowance, is a penalty. We do not believe that. A better descriptor would be "consequences" which can be defined as "a result or affect, typically one that is unwelcome or unpleasant," and the Oxford English Dictionary[19] uses the example "to bear the consequences," meaning "accept responsibility for the negative results or effects of one's choices or action." The Oxford English Dictionary also defines the word penalty as "a punishment imposed for breaking a law, rule, or contract."[20]

It is quite clear that any costs which may be disallowed in a subsequent proceeding are merely the proper consequences of imprudent actions by the utility and do not constitute a penalty. In addition to those consequences however, the Commission has the authority and may in fact impose a penalty when the act that was imprudent also breaks a law, a rule, or contract. As discussed elsewhere in this decision we find that SDG&E and SoCalGas must bear some costs of Safety Enhancement but we impose no fines here based on this record.

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19 http://oxforddictionaries.com/?region=uk

20 SDG&E and SoCalGas fare no better using the equally precise definitions found in Black's Law Dictionary, Sixth Edition, (1980). Penalty: "An elastic term with many shades of meaning; it involves the idea of punishment, corporeal or pecuniary, or civil or criminal, although its meaning is generally confined to pecuniary punishment." Disallowance: "To refuse to allow, to deny the need or validity of, to disown or reject." And, Consequence [singular not plural]: "The result following in natural sequence from an event which is adapted to produce, or to aid in producing, such result."

6.3. Disallowance or Consequences

We find that SDG&E and SoCalGas has over 385 miles of pipeline which do not have documentation of a strength test of at least 125% of Maximum Allowable Operating Pressure.

The Decision Tree shows that at the time SDG&E and SoCalGas filed this application 385 miles were operated in Class 3 or 4 locations or High Consequence Areas that lacked documentation of pressure testing to a carrying capacity of 125% of Maximum Allowable Operating Pressure

Beginning on January 1, 1956 industry standards adopted, and later in 1961, the CPUC adopted, the first strength-testing requirement for transmission pipelines. It is reasonable to require the shareholders of SDG&E and SoCalGas to absorb the costs of pressure testing Phase 1 facilities that were installed after July 1, 1961, but do not have an adequate pressure test record. In addition, if they are replaced without testing, the replacement cost should be reduced by the equivalent cost of testing. This is a reasonable consequence, consistent with ratemaking principles, of not having the otherwise necessary records to validate the testing to then-current standards when the pipeline was installed.

We find that no later than as of January 1, 1956, industry standards provided that all gas pipeline segments operating over 20% Specified Minimum Yield Strength to be strength tested to a level of 125% of Maximum Allowable Operating Pressure in Class 1 and 2 locations and 150% in Class 3 and 4 locations. The required test pressure had to be maintained for a period of no less than 1 hour after the pressure stabilized in all portions of the test sections (i.e., a static pressure test) prior to it entering service. Moreover, Section 841.417 of American Standard Gas Distribution and Transmission Piping System (ASA B31.8-1958), which was subsequently adopted by the Commission in General

Order 112 required operating companies to at a minimum maintain: "for the useful life of each pipeline and main, records showing the type of fluid used for test and the test pressure."

Beginning no later than January 1, 1956 according to industry standards, and then on July 1, 1961, by General Order 112, SDG&E and SoCalGas have been required to strength test all pipeline segments, with a Maximum Allowable Operating Pressure of 20% of Specified Minimum Yield Strength or greater installed beyond these dates, and maintain records to demonstrate compliance. Beginning in 1956 industry standards, and then after July 1, 1961, Commission record keeping requirements evolved to require more specific strength test data to be documented. A prudent system operator should have retained records of these pressure tests. We must decide whether the record for Phase 1 supports applying the 1956 industry standard or the 1961 General Order. The record for Phase 1 of Safety Enhancement shows that SDG&E and SoCalGas assert that they minimally complied with General Order and were not industry leaders adopting the industry standard in 1956. Therefore, for pipeline installed after July 1, 1961, where either SDG&E or SoCalGas cannot produce records that provide the minimum information required by these regulations to demonstrate compliance with the regulatory strength testing and record keeping requirements of General Order 112 and its revisions, as well the requirements of 49 CFR, Part 192 and its revisions beyond the effective date of Part 192, the shareholders must bear the costs of retesting these pipelines.[21] Where replacement of the pipeline is planned

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[21] 49 CFR §192.619(c).

The record shows that interim Federal standards were issued on November 7, 1968, as Part 190 of Title 49 of Code of Federal Regulations (CFR) and became effective on

Footnote continued on next page

rather than test existing pipelines, the system average cost of actual pressure testing should be an offset against the replacement costs of the pipelines for revenue requirement purposes. In this way shareholders bear the costs of remedial pressure tests and ratepayers pay for all other costs of testing or replacing a pipeline.

The mileage shown in the Decision Tree is not directly matched in the Reconciliation. We therefore prepared the following table using the reconciliation to illustrate our adopted ratemaking treatment.

December 13, 1968. The Part 190 adopted the then existing State safety standards for gas pipelines as interim regulations. Effective November 12, 1970, the minimum Federal standards were adopted as Part 192 of Title 49 of the CFR, except for those provisions applicable to design, installation, construction, initial inspection, and initial testing. These exceptions remained in effect in Part 190 until March 13, 1971, when it was adopted into Part 192 and the existing interim standards (Part 190 of Title 49 CFR) were completely revoked.

The 49 CFR §192.517, recordkeeping and retention states: "Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505 and 192.507. The record must contain at least the following information:

> (a) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
>
> (b) Test medium used.
>
> (c) Test pressure.
>
> (d) Test duration[.]
>
> (e) Pressure recording charts, or other record of pressure readings[.]
>
> (f) Elevation variations, whenever significant for the particular test[.]
>
> (g) Leaks and failures noted and their disposition."

SDG&E and SoCalGas	Pipeline Miles[i] Phase 1A/B	Pressure Testing & Replacement Cost Responsibility
Pre-1946 Pipeline	269	Ratepayers Pay for Pressure Testing and/or New Pipeline
1946 Through June 1961	511	Ratepayers Pay for Pressure Testing and/or New Pipeline
July 1961 Through November 1970	29	When SDG&E or SoCalGas Cannot Produce Records Shareholders Pay for Pressure Testing & Absorbs Undepreciated Balances; Ratepayers Pay for New Pipeline
November 1970 to Present	74	When SDG&E or SoCalGas Cannot Produce Records Shareholders Pay for Pressure Testing & Absorbs Undepreciated Balances; Ratepayers Pay for New Pipeline

(i) Reconciliation

As we discussed elsewhere, for any pipeline abandoned or replaced that was installed after July 1, 1961, shareholders must absorb the remaining undepreciated book value. And, as also discussed, ratepayers bear the revenue requirement of the net replacement costs as they benefit from having a new safe and reliable pipeline.

6.4. Safety Enhancement Reasonableness Applications

6.4.1. Minimum Filing Requirements

When SDG&E and SoCalGas file applications to demonstrate the reasonableness of Safety Enhancement they will bear the burden of proof that the companies used industry best practices and that their actions were prudent. This is not a "perfection" standard: it is a standard of care that demonstrates all actions were well planned, properly supervised and all necessary records are retained. At a minimum we would expect that SDG&E and SoCalGas could document and demonstrate an overview of the management of Safety Enhancement which might include: ongoing management approved updates to the Decision Tree and ongoing updates similar to the Reconciliation. The companies should be able to show work plans, organization charts, position descriptions, Mission Statements, etc., used to effectively and efficiently manage Safety Enhancement. There would likely be records of contractor selection controls, project cost control systems and reports, engineering design and review controls, and of course proper retention of constructions records, retention of pressure testing records, and retention of all other construction test and inspection records, and records of all other activities mandated to be performed and documented by state or federal regulations.

6.5. Incentive Compensation

SoCalGas proposes to apply an 18.17% incentive compensation plan overhead loader to its management and associated direct labor costs, and SDG&E proposes a 17.79% incentive compensation plan overhead loader to its management and other direct labor costs. (Ex SCG-10 at 122.)

TURN argues (Opening Brief at 82) that incentive compensation plans usually are designed to reward utility management and employees for meeting specific financial goals that contribute to the shareholders' earnings. TURN goes on that regardless of whether or not it is appropriate for ratepayers fund incentive compensation plans in the normal course of business, incentives for the pipeline safety enhancement plan is clearly not in the ratepayers' best interests.

We note, however, that the usual practice for determining total compensation in the general rate case process for SDG&E and SoCalGas includes not just direct salary, but also various health benefits, retirement contributions, and incentive components. We are concerned here that Safety Enhancement is in large part remediation and we are confronted with the problem of reasonably compensating the workers, who follow the orders of the executives. But ratepayers need not reward management for this remediation. After careful consideration we believe that no employee at or above the level of vice president in any position, directly or indirectly associated with Safety Enhancement, in either SDG&E and SoCalGas, or positions allocated from their parent companies, should receive any incentive compensation for Safety Enhancement to be paid by ratepayers. Any Safety Enhancement incentive compensation for executives should be borne solely by shareholders. We do this solely because we do not want rank and file employees to avoid assignment to Safety Enhancement positions. We expect incentives to be sensibly established: e.g., an incentive for safely meeting schedules, or ensuring all work is performed to industry standards, etc.

We agree with TURN that this is a concern, that this is a remediation program; we are reluctant to include any compensation termed "incentive" and we conclude that no incentive compensation for executives, who as a body manage the companies and made decisions which led us to having to have a remediation program is warranted.

6.6. Pipeline Safety and Reliability Memorandum Accounts

Ordering Paragraph 3 in Dec. 12-04-021 in R. 11-02-019 allowed that:

> San Diego Gas and Electric Company and Southern California Gas Company must file a Tier 2 Advice Letter creating a memorandum account to record for later Commission ratemaking consideration the escalated direct and incremental overhead costs of its Pipeline Safety Enhancement Plan, as described in Attachment A to their January 13, 2012, filing, and costs of document review and interim safety measures as set forth in Attachment B to the January 13, 2012, filing.

On April 20, 2012, SDG&E and SoCalGas submitted Tier 2 Advice Letters 2106-G and 4359 to establish Pipeline Safety and Reliability Memorandum Accounts. Those Advice Letters were approved on May 18, 2012, with an effective date of May 20, 2012. As adopted, these accounts allow SDG&E and SoCalGas to record the actual incremental costs (i.e., operating and maintenance and capital-related costs such as depreciation, income taxes, and return on investment.

7. Pipeline Safety and reliability Memorandum Account Recovery

SDG&E and SoCalGas along with the other respondents to R.11-02-019 were authorized to establish a Pipeline Safety and reliability Memorandum Account Recovery (Memo Account) in D.12-04-021:

> SDG&E and SoCalGas to create a memorandum account in which to record the incremental costs of implementing the Pipeline Safety Enhancement Plan. The Commission will consider whether such properly recorded costs are reasonable and incremental as well as which costs, if any, may be recovered from ratepayers in revenue requirement at a later time in the Triennial Cost Allocation Proceeding.

We believe that there is not a sufficient record on the costs recorded in the Memo Account to authorize recovery at this time. We find that the companies should not recover any management incentive compensation or any costs associated with searching for test records of pipeline testing.

SoCalGas should file an application with testimony and work papers to demonstrate the reasonableness of the costs incurred which would justify rate recovery.

8. Summary of Rate Design and Cost Allocation Issues

This application began as a conventional "phase 2" application to address rate design and cost allocation issues in a proceeding trailing the triennial general rate cases. As already noted Safety Enhancement issues were added to the scope of the proceeding and in addition, parties litigated the question of whether the Safety Enhancement costs required any variance to the existing cost allocation methodology – that is, not allocating the eventual new and higher costs of repaired or replaced pipeline components on the same methodology of the existing pipeline components but perhaps allocating them differently.

This section finds that parties reasonably entered into a settlement of the conventional issues and we therefore adopt it. However we are not persuaded that there is any merit to reallocating the costs of Safety Enhancement. Some parties suggest that safety is somehow a severable service from gas delivery: arguing in essence that the only reason we want the system to be safe is to not kill people if there is an explosion. We do of course want it to be safe and not kill people: but that is a prerequisite of having any pipeline. We therefore reject all proposed changes and find that the new costs of a safe system should be allocated exactly the same way the existing components to be repaired or replaced are allocated.

Additionally, a very limited scope settlement unopposed by any other party was offered between SDG&E and SoCalGas with Clean Energy Fuels Corporation on the appropriate Natural Gas Vehicle compression rate adder. It meets the same criteria that we discuss in detail for the comprehensive rate design settlement (Attachment 3) with all other active parties. The Natural Gas Vehicle compression rate adder settlement is attached to this decision as Attachment 5.

8.1. Customer Charge

The parties correctly noted the proposed decision omitted discussion of a customer charge proposal made by SDG&E. Parties commented on this and we clarify now that we did not adopt a customer charge at this time. We note TURN's concerns that customer charges have a significant impact on the lowest usage customers, and they offset incentives for conservation and energy efficiency by altering the price signals to customers. We find SDG&E's argument that a $5 per month charge sends a significant "cost causation" signal for fixed costs is not persuasive when weighed against the dilution of conservation and energy efficiency price signals. The rate tables attached to this decision did not include a customer charge.

8.2. Conventional Issues Settlement

The active parties of this proceeding followed a consistent trend for San Diego and SoCalGas for a "phase 2 general rate case" by settling the conventional rate design and cost allocation issues that were the core of this original application (before adding in the Safety Enhancement issues). As discussed below we accept the settlement between these experienced and competent parties. An additional issue was raised by parties addressing the cost allocation of Safety Enhancement costs. There is no settlement on that issue and we will consider it separately.

SoCalGas, San Diego, DRA, TURN, Southern California Edison Company (SCE), Coalition, Indicated Producers, California Manufacturers and Technology Association, the City of Long Beach (Long Beach), and Southwest Gas Corporation (collectively, Phase 2 Settling Parties) filed a motion on

March 27, 2013 asking the Commission to adopt the Phase 2 Settlement Agreement[22] (Settlement) attached as Attachment III.[23] As a part of the Settlement the Settling Parties made the necessary recitals to comply with the Commission's settlement rules and summarized the key issues resolved in the settlement and provided all the necessary documentation to fully support an implementable settlement. Due to the length and complexity of the settlement we provide only a brief summary here but defer to the actual settlement as agreed to by the parties. Nothing in this summary interprets or limits the meaning of the settlement itself.

In addition to the settled contested issues fully summarized in the settlement and discussed below, the parties did not contest 28 specific recommendations offered by the Utilities and ORA. These are included with this decision as Attachment 4 to assist the Energy Division with the advice letters needed to implement the final tariffs and rules.

8.3. Settlement Summary

8.3.1. Demand Forecast

Settling Parties use, for the most part, the Applicant's updated demand forecast, including a complete update of 2011 demand data. This reflects a compromise between the litigation positions of various parties.

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[22] On April 15, 2013 Long Beach there was a further motion following approval by the Long Beach City Council to add Long Beach as a party.

[23] The settlement can also be found here: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=62909608

8.3.2. Cost Allocation

8.3.2.1. Long Run Marginal Cost

Settling Parties acknowledge that there exist numerous methodologies proposed by parties to determine marginal unit costs for the customer cost function. Through the negotiation process, however, the Settling Parties were able to identify certain outcomes that, if adopted as a package, would represent an acceptable resolution for each party involved in the settlement discussions. Accordingly, the Settling Parties have taken a "black box" approach to reaching settlement and have agreed to certain modifications to their original cost allocation and rate proposals that are expressly intended to achieve these preferred outcomes.

8.3.2.2. Transition Adjustments

The Settling Parties agreed to a transition adjustment process to reduce the effect of "rate shock" as cost allocation moves towards fully cost-based rates.

8.3.3. Rate Design

8.3.3.1. Transmission Level Service

Settling Parties agree that, for customers who elect service under the Transmission Level Service Reservation Rate Option, quantities in excess of a customer's Daily Reservation Rate Quantity be billed at 115 percent of the Class Average Volumetric Rate. In addition, Settling Parties propose removal of the current requirement to exclude any subsequently allocated base margin portions of the Integrated Transmission Balancing Account from the Reservation Rate Usage Charge. Finally, Settling Parties propose that SoCalGas/SDG&E include in their next cost allocation application data on actual revenues from service provided under the Transmission Level Service Reservation Rate Option and actual volumes provided under that Option.

8.3.3.2. Throughput Risk

Settling Parties agree that noncore transportation revenue requirement continue to be subject to 100% balancing account treatment.

8.3.4. Backbone Operational Issues

8.3.4.1. Reservation Charge

Settling Parties agreed to a reservation charge to be adjusted annually in SoCalGas' Annual Regulatory Account Update filings.

8.3.4.2. Backbone Transmission Balancing Account Rate Adjustments

Settling Parties propose that the SDG&E and SoCalGas Backbone Transmission Service rates be subject to Backbone Transmission Balancing Account rate adjustments.

8.3.4.3. Volumetric Interruptible Backbone Transmission Service Rate

Settling Parties propose that SoCalGas' volumetric interruptible Backbone Transmission Service rate equal its reservation charge Straight Fixed Variable rate.

8.3.4.4. Functionalization of the SDG&E System

Settling Parties propose that the SDG&E transmission system continue to be classified as backbone.

8.3.4.5. Backbone-Only Rate

Settling Parties agree that SoCalGas withdraws its proposal for backbone-only rates from this proceeding, but it may address the question in later proceedings.

8.3.4.6. Modified Fixed Variable Rate Option

Settling Parties agree that SoCalGas' Modified Fixed Variable Rate Option be maintained with the Modified Fixed Variable volumetric rate designed so that 100% load factor Modified Fixed Variable rate equals the Straight Fixed Variable "100% Reservation" rate for Backbone Transmission Service.

8.3.5. Storage

8.3.5.1. Honor Rancho Cost Recovery

Settling Parties propose that SoCalGas receive full rate recovery of its Honor Rancho Expansion Project costs.

8.3.5.2. Extension of the 2009 Phase 1 Settlement Agreement

Settling Parties propose extending the 2009 Phase 1 Settlement Agreement through the end of 2015.

8.3.6. Southern System

Settling Parties propose all Southern System issues be considered in a separate application filed by SDG&E and SoCalGas.

8.4. Applying the Settlement Rules

We find as required by Rule 12.1 of the Commission's Rules of Practice and Procedure (Rules),[24] the proposed settlement is reasonable in light of the whole record, consistent with law, and in the public interest. The settled positions are a balance between the positions as otherwise litigated in the prepared testimony of San Diego and SoCalGas, DRA, and the other parties that served testimony or otherwise actively participated in phase 2. We therefore adopt the attached settlement (Attachment I) without further discussion of the

[24] http://docs.cpuc.ca.gov/WORD_PDF/AGENDA_DECISION/143256.PDF

merits of the individual components. No item settled in this proceeding is dispositive of the appropriate rate treatment in subsequent proceeds. (Rule 12.5.)

We find that the parties had a sound and thorough understanding of the application, and all of the underlying assumptions and data included in the record. This level of understanding of the application and development of an adequate record is necessary to meet our requirements for considering any settlement. These requirements are set forth in Rule 12.1(a)[25] which states:

> Parties may, by written motion any time after the first prehearing conference and within 30 days after the last day of hearing, propose settlements on the resolution of any material issue of law or fact or on a mutually agreeable outcome to the proceeding. Settlements need not be joined by all parties; however, settlements in applications must be signed by the applicant….
>
> When a settlement pertains to a proceeding under a Rate Case Plan or other proceeding in which a comparison exhibit would ordinarily be filed, the motion must be supported by a comparison exhibit indicating the impact of the settlement in relation to the utility's application and, if the participating staff supports the settlement, in relation to the issues staff contested, or would have contested, in a hearing.

Rule 12.1(d) provides that:

> The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

Rule 12.5 limits the future applicability of a settlement:

> Commission adoption of a settlement is binding on all parties to the proceeding in which the settlement is proposed. Unless

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[25] All referenced Rules are the Commission's Rules of Practice and Procedure. (http://docs.cpuc.ca.gov/published/RULES_PRAC_PROC/70731.htm)

> the Commission expressly provides otherwise, such adoption does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding.

The parties clearly demonstrated that they understood the issues, and engaged in a negotiated "give and take" which satisfied the needs of their respective constituents. We therefore find that the proposed "phase 2" settlement comports with Rule 12.1(d), and it is "reasonable in light of the whole record, consistent with law, and in the public interest."

9. A Ruptured Pipe Delivers No Gas – Allocating Safety Enhancement Costs

9.1. Summary of Cost Allocation for Safety Enhancement

Several parties suggest that the Safety Enhancement costs do not contribute to gas delivery service; the costs only reduce the risk of death and injury to people who live or work adjacent to a pipeline should that pipeline rupture or fail. We observe that a ruptured pipeline delivers no gas – to anyone, business or individual – and as we discuss in the Safety Enhancement portion of this decision enhanced safety is also, equally, enhanced reliability. An un-ruptured pipeline (properly constructed and tested) can usually be expected to deliver gas in a reliable fashion to businesses or individuals. We therefore decline to modify any cost allocation to shift Safety Enhancement costs from one customer class to another. The cost of the new safe component should be allocated just as its predecessor was allocated; SDG&E and SoCalGas have shown no persuasive justification to deviate from the existing cost allocation and rate design principles.

9.2. Options for Allocating Safety Enhancement

SDG&E and SoCalGas propose that costs should be allocated to customer classes based on cost causality; we should avoid rate shock (i.e. rapid or large increases) and keep a customer perspective; and we should maintain consistency with current practice whenever possible. (Ex. SCG-12.) SDG&E and SoCalGas's witness specifically argued that the fundamental principle to be followed in allocating costs among customer groups is cost causation which:

> Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs. It is therefore necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The essential element in the selection and development of a reasonable cost allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics, and the costs incurred by the utility in serving those requirements. (*Ibid.*)

As a general rule we would agree with SDG&E and SoCalGas, although we would list consistency ahead of avoiding rate shock as an allocation principle, which is more of a mitigation measure; i.e., we would always want to move to fully allocated costs even if we did so in incremental steps.

Settling Parties suggest that there are two basic ways of allocating Safety Enhancement program costs. In their briefs they argue for their preference of these two methods as we discussed below it is apparent the parties argued based upon how they perceive the cost of Safety Enhancement affecting their rates.

The first of these two approaches is the functionalized approach where the costs are allocated to a particular component of gas service and then in turn finally allocated to different customer class based upon that class's use of each particular component of service. TURN and DRA argue for the functional approach. Coalition argues for different methodology, it proposes that Safety Enhancement related are essentially a one-time remediation rather than an ongoing cost of providing service and should therefore be allocated differently. This party and others argue that the cost should be allocated on an Equal Percentage of Authorized Margin. They argue that Safety Enhancement is fundamentally different from SDG&E and SoCalGas's Transmission Integrity Management Program that they argue is an ongoing program and that Safety Enhancement should be allocated differently. The Coalition calls this an unintended negative consequence and further argues that a functional allocation leads to an inappropriate rate shock and anti-competitive result. (Coalition Opening Brief at 2.)

The Coalition also argues that some cost must be allocated to Backbone Transmission Service customers. It argues that the customers should receive an allocation regardless of whether we adopt a functional method or an equal percentage method because the Coalition believe that a significant portion of Safety Enhancement costs will be incurred on facilities that provide Backbone Transmission Service. (Coalition Opening Brief at 3.) They make a compelling point that this would benefit other customers regardless of the allocation methodology.

9.3. Retaining Existing Cost Allocation and Rate Design

Because no Safety Enhancement costs are directly incurred as a result of this decision, there is no immediate change to implement for cost allocation and rate design. However, we agree with the Coalition that Backbone Transmission Service customers should in the future be allocated Safety Enhancement-related costs to the extent that any pipeline components modified or replaced by Safety Enhancement are used to provide service to Backbone Service customers. Thus, any Safety Enhancement costs that are functionalized as backbone transmission costs are to be allocated to the Backbone Transmission Service customer class consistent with the allocation of the existing rate design.

We disagree with the Coalition's assumption that Safety Enhancement is somehow a one-time cost. As required by Pub. Util. Code § 451, safe operation of a natural gas system is the operator's long-standing and continuing responsibility, not a one-time event. Moreover, an unreliable or ruptured pipeline delivers no gas to any class of customer. No persuasive justification has been presented to apply different cost allocation or rate design principles to Safety Enhancement costs and we decline to adopt a different approach. The cost of these new facilities that replace existing pipeline facilities should be allocated in the same manner as the old facilities were allocated.

10. Categorization and Need for Hearing

This proceeding was categorized as ratesetting and evidentiary hearings were held on phase 1. Safety Enhancement and phase 3, cost allocation issues for the costs of Safety Enhancement. Phase 2 cost allocation, marginal cost and rate design was settled without the need for hearings.

11. Comments on Proposed Decision

The proposed decision of the Administrative Law Judge (Judge) in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. The active parties filed timely opening and reply comments. A number of corrections, clarifications, and revisions have been made to this decision based on those comments, however, where the parties merely reargued their litigation positions we accord those comments no weight.

Specific changes were made to the ratemaking treatment of pipeline segments built between 1956 and 1961. In the proposed decision, based on the available record, a discretionary choice was made to impose the industry standard for testing and record retention beginning in 1956 and not a minimally compliant standard to the Commission's General Order, which did not reflect the change in industry standards until 1961. Based on the comments and reflection on the record we will not impose the 1956 industry standard on Phase 1; we will use instead 1961.

All other changes are intended to improve the clarity of the decision and facilitate SDG&E and SoCalGas' compliance with this decision. One example is where we further clarify here that the application process for SDG&E and SoCalGas to recover the costs in the authorized balancing accounts is subject to a reasonableness review, no costs for Phase 1A/B are preapproved.

Further, based on comments we clarify here that except where we specifically rejected a component of the Decision Tree process to plan and manage Safety Enhancement, SDG&E and SoCalGas may choose to utilize Transverse Flux Imagingin Phase 1A of Safety Enhancement so that this technique may be considered by the Commission in the Test Year 2016 general rate case application as an ongoing alternative to pressure testing or replacing pipeline segments. (Coalition Comments at 13, citing to Ex. SCG-04.) SDG&E and SoCalGas' choice to use Transverse Flux Imaging in Phase 1A would be as a part of demonstrating its reasonable behavior and the applicants may justify its use to recover costs included in the Safety Enhancement balancing accounts. We cannot, however, preapprove the methodology here because we have no record to demonstrate its efficacy.

Edison suggests in its comments that the decision errs in describing the unsafe, and therefore unusable, pipeline that must be replaced as "abandoned" rather than "retired." Edison then compares the abandoned pipeline to electric poles that did not fulfill the forecast useful life. Further, Edison argues the only acceptable use of "abandoned" is when plant never quite enters service. We note that the Federal Energy Regulatory Commission's Uniform System of Accounts uses and defines certain words like retirement and abandonment for specific types of accounting transactions. But this proposed change is unneeded here: an unsafe pipeline must be abandoned and removed from service promptly and safely pursuant to the Safety Enhancement plan adopted herein. SDG&E and SoCalGas even refer to abandoning pipelines in-place, i.e., not digging them up and removing them, but leaving the steel in the ground. You "abandon" a sinking ship; you do not "retire" it. Nor is there a relevant distinction here based on whether utility plant is abandoned before or after it enters service. If Edison's concern is whether ratepayers or shareholders absorb remaining "abandoned" or "retired" plant costs (pipeline, poles, or other,) the concern is misplaced. The relevant facts, circumstances, and the law drive cost recovery applicable to the specific situation. Here, similar costs are recovered differently over time based on the relevant facts, circumstances, and the law.

12. Assignment of Proceeding

Michel Florio is the assigned Commissioner and Douglas Long is the assigned Judge and Presiding Officer in this proceeding.

Findings of Fact

1. SDG&E and SoCalGas are public utilities that operate natural gas pipeline transmission systems subject to the jurisdiction of this Commission.

2. There is an identified need to enhance the safety and reliability of the natural gas pipeline transmission systems operated by SDG&E and SoCalGas. This may include the testing and/or replacement of many segments of these systems.

3. In D.11-06-017, the Commission declared an end to historic exemptions from pressure testing for natural gas pipeline and ordered all California natural gas system operators to file Natural Gas Transmission Pipeline Testing Implementation Plans.

4. Decision 12-12-030 requires that natural gas pipelines must be made safe and reliable.

5. As of July 31, 2011 there were 385 miles identified in the Decision Tree that lack documentation of pressure testing.

6. Industry standards for testing and record retention changed as of January 1956.

7. The Commission's General Order did not adopt the industry standard until 1961.

8. SDG&E and SoCalGas did not consistently follow industry standards until General Order 112 was revised.

9. SDG&E and SoCalGas did not present sufficient project details and cost justification for their proposed ratemaking treatment of Safety Enhancement costs.

10. The Safety Enhancement cost forecasts are inadequate for cost recovery preapproval.

11. The proposed ratemaking to allocate all Safety Enhancement costs to ratepayers was not justified.

12. Balancing accounts will allow SDG&E and SoCalGas to begin Safety Enhancement testing, maintenance, and new construction.

13. Balancing accounts will allow SDG&E and SoCalGas an opportunity to recover reasonable costs for Safety Enhancement.

14. The companies proposed inclusion of incentive compensation in the costs of Safety Enhancement.

15. Incentive compensation is an integral part of employee compensation for SDG&E and SoCalGas.

16. Executive incentive compensation for Safety Enhancement paid by ratepayers is not justified.

Rate Design Settlement

17. The active parties in phase 2 have reached a settlement on all outstanding disputed rate design issues except the rate design proposals for Safety Enhancement costs and SDG&E's customer charge proposal.

18. There is an unopposed related settlement that resolves the Natural gas vehicle Compression rate adder.

19. The rate design settlements comport with the Commission's settlement rules and resolve all issues except the rate design proposals for Safety Enhancement costs and SDG&E's customer charge proposal.

20. The parties memorialized 28 specific uncontested issues.

21. SDG&E proposed a customer charge for recovery of some fixed costs.

22. A customer charge dilutes the price signals for conservation and energy efficiency.

Cost Allocation for Safety Enhancement

23. The proposed allocation of costs of the new pipeline, which replaces the existing pipeline, would reallocate costs between customer classes with no change in service.

24. The existing cost allocation, as settled, allocates costs to customer classes based upon the costs incurred to serve those customers.

25. Safety Enhancement does not change the service provided to customers although it does likely improve reliability by replacing existing pipelines with new pipelines that meet industry and Commission required safety standards.

26. The ratepayers will be served by a safe and reliable system with new components that will operate for decades.

Conclusions of Law

1. As required by § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified," as provided in § 454.

2. Pub. Util. Code § 451 requires safe operation of a natural gas system. It is a long-standing and continuing responsibility, not a one-time obligation.

3. The burden of proof is on SDG&E and SoCalGas to demonstrate that it is entitled to the relief sought in this proceeding, including affirmatively establishing the reasonableness of all aspects of the application.

4. The standard of proof that SDG&E and SoCalGas must meet is that of a preponderance of evidence, which means such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.

5. The Decision Tree analysis used to evaluate the existing pipeline network for safety, documentation, and reliability, is a reasonable but not final process.

6. Although industry best practices had changed by January 1, 1956, the Commission only adopted those standards in 1961.

7. The record for Phase 1 of Safety Enhancement supports the application of the July 1, 1961 adoption of the Commission's General Order 112 for testing and record-retention.

8. The analytical approach for Phase 1 in the Decision Tree management process, as fully described in testimony by SDG&E and SoCalGas, should be approved.

9. The Safety Div. should oversee Safety Enhancement to ensure public safety during the design, maintenance and construction phase as well as ensure safety in the future operations of the modified pipeline systems.

10. The Commission has the authority to delegate stop work order authority to Safety Div.

11. The Commission must ensure parties have timely procedural opportunities for a review of any action or stop work orders issued by Safety Div.

12. The proposed ratemaking for Safety Enhancement should not be approved.

13. It is reasonable for SDG&E and SoCalGas' shareholders to absorb the portion of the Safety Enhancement costs that were caused by any prior imprudent management. SDG&E and SoCalGas should absorb the costs of pressure testing where the company cannot produce records that provide the minimum information to demonstrate compliance with the industry or regulatory strength testing and records keeping requirements of industry standards beginning with the adoption of General Order 112 and its revisions, as

well as the requirements of 49 CFR, Part 192 and its revisions beyond the effective date of Part 192.

14. Where Phase 1 pipelines are replaced without testing SDG&E and SoCalGas should absorb an amount equal to the average cost of pressure testing where the company cannot produce pressure test records after the adoption of General Order 112, effective July 1, 1961.

15. SDG&E and SoCalGas should absorb the un-depreciated balances of any abandoned pipelines wherever they should have Phase 1 testing records after July 1, 1961, and do not.

16. The inclusion of executive incentive compensation in the costs of Safety Enhancement recoverable from ratepayers was not justified.

17. SDG&E and SoCalGas should be authorized to file annually after December 31, 2015 to recover the reasonable costs recorded in the Safety Enhancement balancing accounts.

18. Subsequent applications to review the Safety Enhancement Capital Cost Balancing Accounts and a Safety Enhancement Expense Balancing Accounts should be filed with sufficient detail to justify the work performed pursuant to the analytical approach embodied in the Decision Tree and the reasonableness of those costs. SDG&E and SoCalGas should be allowed to file annually for the costs of completed projects.

19. It is reasonable to require the ratepayers to pay for the costs to repair or rebuild the system that SDG&E and SoCalGas demonstrate are just and reasonable costs.

20. A valid record of a pipeline pressure test must include all elements required by regulations in effect at the time the test was conducted.

21. It is reasonable to require SDG&E and SoCalGas to comply with 49 CFR Part 192, subpart J pressure test specifications when conducting pressure tests pursuant to the plan approved herein.

22. SDG&E and SoCalGas have justified the concept of a Phase 1A and Phase 1B.

23. SDG&E and SoCalGas costs incurred prior to the effective date of today's decision should be subject to approval based on a reasonableness review of the Pipeline Safety and Reliability Memorandum Accounts.

24. The reasonableness issues identified by ORA and TURN will be addressed in the reasonableness review applications for the balancing accounts.

25. There is no justification for any executive incentive compensation component to be added into the costs of Safety Enhancement recovered from ratepayers.

Rate Design Settlement

26. The Commission has the authority to adopt a settlement when it is reasonable in light of the whole record, consistent with law, and in the public interest.

27. The proposed rate design settlement is reasonable in light of the whole record, consistent with law, and in the public interest and should be adopted.

28. The uncontested issues are reasonable in light of the whole record, consistent with law, and in the public interest and should be adopted.

29. The uncontested Natural gas Vehicle compression rate adder settlement is reasonable in light of the whole record, consistent with law, and in the public interest and should be adopted.

Cost Allocation for Safety Enhancement

30. The existing cost allocation methodology is reasonable for the costs of Safety Enhancement because these costs are necessary to safely and reliably supply natural gas to existing customers in the same manner as the existing system serves customers.

31. This decision should be effective today.

32. This proceeding should be closed.

ORDER

IT IS ORDERED that:

1. We adopt the Phase 1 analytical approach for Safety Enhancement to ensure the safety and reliability of San Diego Gas & Electric Company and Southern California Gas Company as embodied in the Decision Tree (Attachment I) and Reconciliation (Attachment 2) and related descriptive testimony.

2. We authorize San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) to begin work as described in their Safety Enhancement Plans with costs recorded in balancing accounts and subject to refund pending a subsequent reasonableness review.

3. The Director of the Commission's Consumer Protection and Safety Division, or designee, (Safety Div.) is delegated the following specific authority to act in addition to all existing general authority delegated to staff:

(a) Safety Div. may inspect, inquire, review, examine and participate in all activities of any kind related to Safety Enhancement. San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas), all of their contractors shall immediately provide any document, analysis, test result, plan, of any kind related to

Safety Enhancement as requested by Safety Div.'s staff or its contractors. Safety Div. must subsequently confirm all requests in written form, however all responses to must be immediate.

(b) Safety Div. may issue immediate stop work orders to SDG&E and SoCalGas, and all of their contractors when necessary to protect public safety. SDG&E and SoCalGas must comply immediately.

(c) The Commission's Executive Director, and the Chief Administrative Law Judge, together shall ensure that SDG&E and SoCalGas, and all other parties to this proceeding, shall have timely procedural opportunities for a review of any action or stop work orders issued by Safety Div. as may be feasible under the specific circumstances whenever Safety exercises its delegated authority.

(d) Safety Div. must formally file a copy of any Stop Work Order in this proceeding by the close of business on the workday following its issuance to either SDG&E and SoCalGas, or any contractors.

4. Within 30 days of the effective date of this decision San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) must file Tier 2 Advice Letters to establish a Phase 1 Safety Enhancement Capital Cost Balancing Account and a Phase 1 Safety Enhancement Expense Balancing Account to record the expenditures incurred pursuing the Safety Enhancement proposals adopted in Ordering Paragraph 1. These accounts may be effective as of the date of this decision.

5. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) may file annually after December 31, 2015 for reasonableness review of the completed projects recorded in the Phase 1 Safety Enhancement Capital Cost Balancing Account and annually for the expenses recorded in the Phase 1 Safety Enhancement Expense Balancing Account.

SDG&E and SoCalGas may alternatively file for preapproval of specific projects seeking approval of a cap or for other specific guidance.

6. Cost recovery of the Pipeline Safety and Reliability Memorandum Accounts for San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) will be reviewed for reasonableness in a new application or applications. In addition to the other requirements to demonstrate reasonableness, SDG&E and SoCalGas are limited to the recovery of only those costs that directly contribute to the implementation of Safety Enhancement.

7. The comprehensive rate design settlement (Attachment 3) between San Diego Gas & Electric Company (SDG&E) and all active parties and adopts a rate design settlement between Southern California Gas Company (SoCalGas) and all active parties is adopted. This settlement resolved all contested issues except the rate design proposals for SDG&E and SoCalGas' Safety Enhancement costs. We also adopt for implementation the 28 uncontested issues included in Attachment IV.

8. The Natural gas Vehicle compression rate adder settlement is adopted.

9. We reject all proposed modifications to the existing cost allocation methodology proposed by San Diego Gas & Electric Company and Southern California Gas Company and the parties for Safety Enhancement costs. Safety Enhancement costs will be allocated consistent with the existing cost allocation and rate design for the companies.

10. Within 30 days of the effective date of this decision San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) must file Tier 1 Advice Letters to implement the rate design settlements and uncontested issues as contained in Attachments III, IV and V.

11. This decision denies San Diego Gas & Electric Company's request for a residential customer fixed charge.

12. Application 11-11-002 is closed.

This order is effective today.

Dated June 12, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

ATTACHMENT B

ORA EXHIBIT 20 IN A.13-12-012

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for Authority To Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding.	Application 11-11-002 (Filed November 1, 2011)

REPLY BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES ON ALLOCATION OF PIPELINE SAFETY ENHANCEMENT PLAN COSTS

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June 21, 2013

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I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure, and the schedule set by Administrative Law Judge Long, the Division of Ratepayer Advocates (DRA) submits this Reply Brief to address some of the arguments made by other parties regarding the appropriate allocation of the costs of the Pipeline Safety Enhancement Plan ("Plan" or "PSEP") of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E).

DRA continues to recommend that the Commission allocate Plan costs using the "functionalized" method. This functionalized method should include an allocation to Backbone Transmission Service, and should allocate transmission and high pressure distribution costs using demand factors. For 2013, using Sempra's "Proposed Case" revenue requirement, the result would be a 53.9% share to core customers, a 43.8% share to non-core customers, and a 2.3% share to Backbone Transmission Service.[1] The functionalized allocation of Plan costs is the most equitable method to use because it relies upon long-standing cost of service ratemaking principles as described in DRA's Opening Brief.

II. BACKGROUND

DRA's Opening Brief discusses the background to this case.[2]

III. PIPELINE SAFETY ENHANCEMENT PLAN COST ALLOCATION

A. Policy/ General Principles for Cost Allocation

The parties submitting Opening Briefs in this phase of the case all seem to agree that the Commission's guiding principles for allocation of natural gas transportation costs focus on cost causation, economic efficiency and equity. There is, however, considerable disagreement about how these principles should be applied to the allocation of Sempra's proposed Pipeline Safety Enhancement Plan costs.

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[1] Ex. SCG-136, p. 1, "Rates Assuming 2013 PSEP Revenue Requirement of $103.58 Million and Various Allocation Methodologies", p. 1, Column L. DRA's Opening Brief erroneously listed the percentages as a 56.4% % share to core customers, a 41.4% share to non-core customers, and a 2.3% share to Backbone Transmission Service. (DRA Opening Brief, p. 1.) DRA agrees with the caution of The Utility Reform Network (TURN), however, that the rate impacts presented in Ex. SCG-136 "… are only as accurate as the assumed revenue requirement. By assuming the very highest possible revenue requirement, the comparison table presents the very highest possible rates that would result under any of the proposed scenarios." (TURN Opening Brief, p. 6.)

[2] DRA Opening Brief (October 2012), pp. 5-7; DRA Opening Brief (May 2013), p. 2-3.

The Sempra Utilities and the non-core customer parties all advocate the use of the Equal Percent of Authorized Margin ("EPAM") allocation method. DRA and The Utility Reform Network (TURN) recommend that the Commission use the functionalized allocation method.

DRA's Opening Brief addresses its opposition to the use of the Equal Percent of Authorized Margin for allocation of these costs in this case. In this Reply Brief, DRA addresses arguments made in the Opening Briefs of other parties.[3]

B. Cost Allocation Methodology for Pipeline Safety Enhancement Plan Costs

Allocation of Plan costs using the functionalized approach and a volumetric surcharge for both residential and non-residential customers meets the Commission's goals of ratemaking that is based on cost causation, promotes economic efficiency, and is equitable. An allocation using the Equal Percent of Authorized Margin meets none of these goals.

1. Equal Percent of Authorized Margin

a) Cost Causation

DRA's Opening Brief already addresses the arguments of the non-core parties which claim that it is the core customers, those "… who live and work within the [Potential Impact Radius] of a gas transmission line…"[4] who are the cost causers of the Plan costs.[5]

Some of the non-core parties persist in this attempt to create an artificial separation between safety and reliability for purposes of allocating costs of Sempra's Pipeline Safety Enhancement Plan. For example, the California Manufacturers and Technology Association (CMTA) argues in its Opening Brief that, "Since the Commission's focus on pipeline safety is what is 'driving' PSEP costs in this proceeding, then, 'on the basis of cost causation principles, PSEP costs should be allocated to those classes that will benefit from an enhancement of pipeline safety."[6] CMTA's authority for this statement is the testimony of the Southern California Indicated Producers (SCIP).

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[3] Silence on any matter not specifically discussed should not be interpreted as assent.

[4] Ex. SCIP-100, p. 15; See also The City of Long Beach Gas & Oil Department Opening Brief, p. 3.

[5] DRA Opening Brief, pp. 7-9

[6] CMTA Opening Brief, p. 5, citing to Ex. SCIP-101, p. 4.

To DRA's knowledge, the Commission has never held that core customer classes are the principal cost causers of safety-related costs. And, as TURN points out in its Opening Brief, "… the Commission should not effectively create a new PSEP function, just as it has never created a separate safety or reliability function. Rather, the safety and reliability-related work that the Commission authorizes the utilities to pursue through their Pipeline Safety Enhancement Program are the newest examples of work tied to the safe and reliable operation of the Sempra Utilities' backbone transmission system, their local transmission system, and the high pressure distribution system."[7]

In its Opening Brief, Edison seems to be suggesting that the Commission should use the Equal Percent of Authorized Margin method because there is some ambiguity about cost causation for the gas transmission pipeline safety program costs. According to Edison, "… when there is no clear cost causation, it makes more sense to scale the total costs rather than setting the rates on a functional basis."[8] Edison then goes on to cite a Commission decision which says, "We find EPMC [Equal Percent Marginal Cost] by total to be appropriate for natural gas as well as electric ratemaking."[9]

But the underlying premise of Edison's argument is wrong. The cost causation for the Commission's Pipeline Safety Enhancement program could not be more clear. It is part of an effort to ensure that natural gas transmission pipeline operators transport gas in a manner that meets the requirements of Public Utilities Code Section 451 to "… promote the safety, health, comfort, and convenience of its patrons, employees and the public."[10] The functionalized cost allocation allocates Plan costs using equitable cost of service principles.

Edison's Opening Brief offers a "test" of whether transmission customers are "… causing PSEP costs that should be 'functionalized' and allocated using the same functional allocators as are used for other costs."[11] According to Edison, the "test" is whether the PSEP costs would vary

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[7] TURN Opening Brief, p. 12.

[8] SCE Opening Brief, p. 4.

[9] SCE Opening Brief, p. 4.

[10] Public Utilities Code §451; See also *Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement Or Testing Implementation Plans* (2011), D.11-06-017, mimeo, p. 18.

[11] SCE Opening Brief, p. 6.

in any material way with transmission customer demand.[12] Edison notes that the "[t]traditional demand driver for transmission level service customers is peak throughput" and concludes that "[i]t is dubious, if not completely improbable, that PSEP costs are being materially driven by a traditional demand variable from any customer class."[13]

DRA agrees with Edison that the traditional demand driver for transmission level service customers is peak throughput, but it is Edison's conclusion that is "completely improbable." Since Sempra's Pipeline Safety Plan costs are being driven by requirements to assure safe and reliable transportation of natural gas, the obvious cost driver is indeed the demand drivers such as peak throughput. The Plan costs should, therefore, be allocated on a functionalized basis which adheres to cost of service principles.

The reason that the majority of distribution costs are allocated to core customers is because the majority of distribution-related costs are incurred to provide service to core customers and not non-core customers. With respect to the Pipeline Safety Enhancement Plan, however, the primary elements of the program are associated with the testing and replacement of "transmission" (in contrast to distribution) pipelines.[14] There is no evidence that these enhancements will operationally serve anything other than a transmission-related function. Therefore, the Plan costs should be allocated on a functionalized basis consistent with the method being used to allocate all costs on the SoCalGas and SDG&E system. The Plan costs do not warrant a departure or deviation from the existing cost allocation method.

As DRA noted in its Opening Brief, the utilities' systems are designed, constructed and operated to meet customers' peak requirements.[15] In order to maintain that safe service to customers, the utilities must now test or replace all in-service gas transmission pipelines that have not been tested, or for which the utilities do not have adequate records of maximum allowable operating pressure.

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[12] SCE Opening Brief, p. 6.

[13] SCE Opening Brief, p. 6.

[14] As defined by US Federal Code of Regulations for transmission pipelines. See Ex. DRA-2, p. 16, citing 49 CFR 192.

[15] DRA Opening Brief, p. 5.

The Commission order to pressure test or replace was triggered by the safety concern arising from missing records.[16] To address the safety concern expressed in D.11-06-017, the California utilities, including Sempra, were ordered to submit their comprehensive natural gas transmission Pipeline Safety Enhancement Plans.[17] The Sempra utilities submitted their Plan in Phase I of this Triennial Cost Allocation Proceeding.[18]

At the heart of the decision-making process in Sempra's Plan is a Decision Tree which starts with pipeline data assessment information that feeds into the Decision Tree.[19] Sempra used the Decision Tree outcomes of the Criteria[20] segments and then added the non-HCA segments to the scope of work outside of the Decision Tree.[21] Sempra also used the outcomes of the Decision Tree to determine and prioritize "accelerated miles"[22] into Phase IA.[23] In Phase IA of the Sempra Plan, subsequent actions (i.e., to test or replace) would depend on whether the pipelines can be taken out of service with manageable customer impact and whether pipelines are capable of being pigged.[24]

Ultimately, if the Sempra Decision Tree results in a pipeline replacement for a transmission line segment, then the expectation is that a similar size pipe of the same capacity will replace the original pipe. Neither a smaller pipe nor a larger pipe capacity will be a suitable replacement because the appropriate size of the pipe to replace the original pipe is determined based on the customer demand drivers on the system. If a higher capacity pipe replacement is instead installed to replace an identified segment, then this would constitute a betterment

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[16] 13 RT 2014: 9 – 22, DRA/Sabino.

[17] D.11-06-017, Ordering Paragraphs #1 through 10.

[18] *See* Sempra Opening Brief, (Phase 1) October 2012, p.2.

[19] As shown in Figure 2, Sempra Opening Brief, (Phase 1), October 2012, p. 74.

[20] Sempra uses the term "Criteria Miles" to refer to pipelines in "Class 3 and Class 4 locations and Class 1 and Class 2 High Consequence Areas ("HCAs")." (Ex. DRA-2 (Phase 1), p. 5.)

[21] Ex. DRA-2 (Phase 1), pp.10-11.,

[22] Sempra uses the term "Accelerated" mileage to refer to segments that are identified as Category 1, 2, and 3, located in both High Consequence Areas and non-High Consequence Areas. Category 1, 2, and 3 segments have already demonstrated a safety margin through prior strength testing or with Maximum Allowable Operating Pressure. (Ex. DRA-2, (Phase 1), pp. 7-8.)

[23] Ex.DRA-2 (Phase 1), p. 11 citing Sempra's response to DRA-DAO-9, Q.1.

[24] Sempra Opening Brief (Phase 1) October 2012, p.74, Figure 2.

project[25] relative to the original pipe. In that sense, the Plan costs that were triggered by safety concern for the missing records are demand-driven since they should mimic the design criteria of the original pipe segments to meet the customer peak requirements. Essentially, a pipeline may be replaced earlier than intended based on the lack of records. But for the Pipeline Safety Enhancement Plan, if the transmission pipeline was to be replaced in ten years, the cost would have been allocated on a functionalized basis. There is no convincing evidence offered that an earlier transmission pipeline replacement requires a separate, new method of cost allocation. Safe transmission of natural gas is the reason for the Plan costs, the cost of service link with usage and function remains the same.

If the Sempra Decision Tree results in pressure testing, then according to Sempra, for short segments of pipeline "the logistical costs associated with pressure testing (permitting, construction, water handling, service disruptions for non-looped system) can approach or exceed the cost of replacement."[26] Moreover, "…pressure testing an in-service pipeline can cause service outages anywhere from two to several weeks. In addition, while there is little variability in the length of time it takes to tie in a replacement line to the existing system (less than one day to two days), there can be significant variability of how long customers will be without service for pressure testing. Small leaks to outright failures can occur, taking anywhere from a day to weeks to repair. There may also be problems removing hydrotest water from the pipeline segment."[27] For longer segments "Where service disruption is not likely to be feasible, the pipelines are either identified for abandonment or for pressure testing once new replacement pipelines have been installed to maintain service to customers."[28] It is thus clear that pressure testing costs can vary depending on how long customers will be without service for pressure testing, and thus could incur costs to maintain service to avoid disruptions.

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[25] See Ex. SCG-35 (Phase 1), p. 135.

[26] Sempra Opening Brief (Phase 1) October 2012, p.76 citing Ex. SCG-04, p. 53.

[27] Sempra Opening Brief (Phase 1) October 2012, p.77, citing Ex. SCG- 20, p. 7. *See also* 6 RT 1081 (Phillips/ Sempra): "So there's a number of costs we have to look into when we evaluate a pipeline. If we're going to evaluate it, test it, rather than replace it, modifications we have to make to the pipeline to make it available to hydrostatically test. We haven't designed the system to be filled with water and taken out of the system for six weeks. We haven't designed the system that way in the 80 years we've been designing the system. We have to look at the cost to that."

[28] Sempra Opening Brief (Phase 1) October 2012, p.78, citing Ex.SCG-04, p. 55.

DRA's witness was asked to explain the cost driver of the Plan during cross examination by counsel for SCE:[29]

> MR. ARCHER: Q. What demand driver? You didn't say earlier today that the main cost driver of PSEP was safety?
>
> A. I was explaining that safety is integral to the provision of safe and reliable gas transportation service. And to the extent those gas transportation services are demand driven, those safety costs are also demand driven.
>
> Q. So if throughput increases by five percent on the SoCalGas system, will PSEP costs increase by five percent? That's a demand driver, right, throughput?
>
> A. PSEP costs, you're asking a direct link with PSEP costs and the increase in throughput?
>
> Q. Any sort of link.
>
> A. The relationship is not a direct proportionate increase.
>
> Q. How about if throughput decreases
>
> by five percent, does that decrease PSEP costs?
>
> A. Again, the relationship is not directly proportionate.
>
> Q Assume that no pipes are taken out of service but people just use less gas, throughput goes down by five percent. Wouldn't SoCalGas have to spend the exact same amount of money on PSEP?
>
> A. If the exact same amount have missing records, I don't see any reduction from the proposed amount if the Commission adopts that proposed amount.
>
> Q. Same with other traditional demand measures other than throughput, would your answer be the same?
>
> A. Yes.

Pipeline safety cuts across the several gas transportation service functions Sempra provides. The associated Plan costs to test or replace are, therefore, best allocated based on the function of the underlying assets, i.e., Plan costs for transmission are allocated based on the demand drivers for the transmission function and Plan costs for high pressure distribution are allocated based on the demand drivers for the high pressure distribution function. Clearly, the functionalized method is the most appropriate means of allocating Plan costs.

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[29] 13 Tr.2067, line 19 – 2068, line 27 (Sabino/ DRA).

Edison and the Southern California Generation Coalition (SCGC) also argue that "[b]ecause PSEP costs … are backward-as opposed to forward-looking…" they are non-economic costs and should be allocated based on the Equal Percent of Authorized Margin basis.[30] According to SCE, "PSEP costs are being caused by the imposition of a comprehensive pipeline testing system that is backward-looking and unrelated to customer demand."[31]

SCE seems to equate "non-economic costs" with non-demand driven costs. As discussed above, Plan costs cannot be unrelated to customer demand. As long as Sempra has throughput flowing on its system to provide gas transportation service and customers agree to take gas transportation service, safety is integral to gas transportation service.

In any event, the authority SCE and SCGC cite for their argument is the Commission's decision allocating the Competition Transition Cost (CTC) charges from electric restructuring. However, as TURN explains in its Opening Brief, the CTC charges and the Pipeline Safety Plan costs are hardly analogous. The "CTC was intended to permit rate recovery of the uneconomic portion of existing electric generation investments from years and, in some instances, decades past, whereas here PSEP projects will entail incremental spending limited to activities related to gas transmission and distribution facilities."[32] Moreover, the "system average percent change" allocation the Commission used for CTC costs, was required by statute "…in order to ensure that cost recovery among the classes was 'in substantially the same proportion as similar costs are recovered as part of the electric industry restructuring." As TURN points out, there is no such statutory requirement for PSEP-related costs.[33]

b) Equity

In its Opening Brief, SCIP invokes the principle of "equity" to argue that, using the EPAM method, "[a]ll end-use customers would make a roughly equal percentage contribution to the PSEP costs, in fair proportion to their asserted equal benefits from PSEP."[34] The EPAM method SCIP advocates allocates about 95% of the costs of the Sempra Plan to core customers

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[30] SCE Opening Brief, p. 7; SCGC Opening Brief, p. 10.

[31] SCE Opening Brief, p. 5.

[32] TURN Opening Brief, p. 10.

[33] TURN Opening Brief, p. 10

[34] SCIP Opening Brief, p. 9.

and 5% to non-core customers[35] and 0% to Backbone Transmission Service.[36] The record evidence shows that there are significant amounts of PSEP costs for the backbone transmission function in Phase IA of the Applicants' Proposed Case.[37] If no PSEP costs are allocated to the backbone transmission service function, then regardless of the cost allocation methodology, those backbone transmission-related PSEP costs will be allocated instead to the core and noncore customers. But under an EPAM allocation, without any Plan allocation to the backbone transmission function, the core customers will be absorbing most of the Plan costs, including those for the backbone transmission function.[38] The EPAM excluding the backbone transmission supported by SCIP is clearly an inequitable cost allocation which the Commission should not adopt. There is no valid reason to give gas marketers and other backbone transmission subscribers a free ride at the expense of both core and noncore end-use customers.

Moreover, as TURN notes, equity is not achieved "…by adopting a PSEP surcharge of approximately 8.2 cents per therm for residential customers, but less than 1.0 cent per therm for non-core commercial and industrial customers served at distribution level, and only 0.13 cents per therm for transmission level service."[39]

SCIP also offers what it calls a "moderated approach" in the event its "pure EPAM" recommendation is rejected.[40] Under SCIP's "moderated approach," "[t]he Commission could … choose to adopt a hybrid approach, and use each bookend methodology[41] to allocate one-half of the PSEP costs. This would moderate the harmful effects of a functional allocation, while still applying to half the PSEP costs."[42] The alleged "harmful effects" of a functional allocation that includes a Plan cost allocation to the backbone transmission function, have not been demonstrated.

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[35] 10 RT 1681, lines 14-19, Morrow/ Sempra.

[36] Ex.SCG-136, p. 1, Column (b).

[37] Ex. SCGC- 102.

[38] Ex. SCG-136, p.1 Column (b).

[39] TURN Opening Brief, p. 9.

[40] SCIP Opening Brief, p. 3.

[41] DRA assumes the "bookends" SCIP refers to are the EPAM allocation at one end, and DRA's proposed functionalized approach, on the other.

[42] SCIP Opening Brief, p. 17.

Apart from unsubstantiated threats of bypass (by non-core customers) and claims of rate shock (to non-core customers), there is no factual evidence in the record that a functionalized allocation will have any harmful effects. There is, however, direction from the Legislature that pipeline safety investments be done in a manner "…consistent with the need for just and reasonable cost-based rates."[43] The evidence clearly shows that the functionalized approach, if applied to a reasonable revenue requirement, will meet the statutory requirement of just and reasonable cost-based rates.

c) "Multiplier" Effect

DRA's Opening Brief addresses these arguments.[44]

d) Threat of Bypass

DRA's Opening Brief addresses these arguments.[45]

2. Functionalized Allocation Method

As DRA discusses in its Opening Brief, the "functionalized" allocation method apportions costs based on the function of the underlying asset.[46] Like the other non-core parties, SCGC opposes the use of the functionalized method. However, in the event that the Commission elects to functionalize and then allocate Plan costs, SCGC recommends that Commission allocate high pressure distribution costs on a Long Run Marginal Cost (LMRC) basis, rather than an embedded cost basis.[47]

DRA disagrees. This proceeding is part of a Commission-wide program for natural gas *transmission* pipelines. From the evidence in Phase 1A of this case, it appears that Sempra uses the term "High Pressure Distribution" to describe pipelines that meet the definition of the U.S Code of Federal Regulations for *transmission* pipelines.[48]

DRA, therefore, has focused its recommendations on the costs Sempra includes for its natural gas transmission system. DRA opposes any attempt in this proceeding to burden

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[43] Public Utilities Code §963(b)(3).

[44] DRA Opening Brief, pp. 9-10.

[45] DRA Opening Brief, p. 10.

[46] DRA Opening Brief, pp. 12-13.

[47] SCGC Opening Brief, p. 24.

[48] See Ex. DRA-2, p. 16, citing 49 CFR 192.

ratepayers with costs associated with natural gas *distribution* unless they fall within the federal definition of transmission. As to those costs which are named "distribution" in Sempra's record-keeping system, but which actually serve the transmission function, they should be treated as transmission costs and allocated using embedded costs, the method adopted by the Commission when it approved the settlement in D.09-11-006.[49]

3. Other

DRA has no other issues to raise at this time.

C. Allocation to Backbone Transmission Service

DRA's Opening Brief addresses this issue.[50]

IV. PIPELINE SAFETY ENHANCEMENT PLAN RATE DESIGN

A. Line Item Surcharge

DRA's Opening Brief addresses this issue.[51]

B. Fixed or Volumetric Surcharge

DRA's Opening Brief addresses this issue.[52]

V. CUSTOMER CHARGE FOR SDG&E RESIDENTIAL NATURAL GAS CUSTOMERS

DRA has no comment on this issue at this time.

VI. UNCONTESTED PROPOSALS

DRA has no comment on these proposals at this time.

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[49] *Opinion Regarding the Settlement of Phase Two Issues* (2009) D.09-11-006, Appendix A, p. 9, Section II.B.1.A.

[50] DRA Opening Brief, p. 15.

[51] DRA Opening Brief, p. 15.

[52] DRA Opening Brief, p. 15.

VII. CONCLUSION

For all the foregoing reasons, DRA asks that its recommendations, set forth in testimony and in its Briefs, be adopted.

Respectfully submitted,

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June 21, 2013

ATTACHMENT C

ORA EXHIBIT 20 IN A.13-12-012

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902G), and Southern California Gas Company (U904G) for Authority to Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding.	Application 11-11-002 (Filed November 1, 2011)

OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES ON ALLOCATION OF PIPELINE SAFETY ENHANCEMENT PLAN COSTS

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May 24, 2013

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I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure, and the schedule set by Administrative Law Judge Long, the Division of Ratepayer Advocates (DRA) submits this Opening Brief to present its recommendations on the appropriate allocation of the costs of Phase 1A of the Pipeline Safety Enhancement Plan (Plan) of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E).

DRA recommends the Commission allocate the Plan costs as it does other backbone/ local transmission and distribution costs. This means that the Plan revenue requirements for Phase 1A would be separated between the transmission and distribution functions for each utility, and allocated based on the function of the underlying assets.[1] This allocation by function would result in a 56.4% share to core customers, a 41.4% share to non-core customers, and a 2.3% share to Backbone Transmission Service.[2] For the reasons discussed below, DRA recommends that the Commission adopt this allocation.

II. BACKGROUND

SDG&E and SoCalGas, (collectively, the Sempra Utilities or Sempra) first filed their Pipeline Safety Enhancement Plan in the Commission's Rulemaking 11-02-019. Rulemaking (R.) 11-02-019 was opened "… to review and establish a new model of natural gas pipeline safety regulation for California." In April 2012, the Commission transferred consideration of the Sempra Utilities' Safety Enhancement Plans to Sempra's Triennial Cost Allocation Proceeding (TCAP) Application (A.) 11-11-002.

The Scoping Memo for A.11-11-002 established two phases for consideration of Sempra's Plan: the first would evaluate the scope and reasonableness of Sempra's Plan and its costs; the second would determine the allocation of both the Plan and non-Plan costs. The active parties to this proceeding reached a settlement on the cost allocation of non-Plan costs. That settlement is pending. Still in dispute is the proper allocation of the Plan costs.

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[1] Ex. DRA-106, pp. 1-3 – 1-4.

[2] *See* Ex. SCG-136.

For the years 2012 through 2015 of their Plan, the Sempra Utilities ask the Commission to order ratepayer funding of a total of approximately $1.94 billion in direct costs.[3] As DRA noted in its testimony and in its October 2012 Briefs, DRA opposes saddling Sempra ratepayers with the majority of the costs of what Sempra calls its "Proposed Case." Most of these costs are for work that Sempra should have been performing all along, or are for projects that are outside the scope of this proceeding, or are based on estimates extravagantly beyond credible evidence. DRA recommends that the Commission authorize ratepayer funding of no more than $69.75 million for the combined utilities for the years 2012 through 2015.[4]

Until a final decision is issued in the first phase of this proceeding, the Pipeline Safety Enhancement Plan costs that are the subject of this cost allocation phase are illustrative only. Whatever decision the Commission ultimately reaches, however, DRA's recommendations as to cost allocation remain the same. Plan costs, like all other backbone/ local transmission costs, should be allocated by function, an approach that has been used in past Biennial Cost Allocation proceedings[5]

III. PIPELINE SAFETY ENHANCEMENT PLAN COST ALLOCATION

A. Policy/General Principles for Cost Allocation

In this phase of the case, the Commission will consider the reasonable allocation of the cost of service to the various customer classes, and then develop a rate design that will provide a reasonable opportunity for SDG&E and SoCalGas to recover the cost of service from their respective customer base. As stated in the Scoping Memo, "…all issues of cost-causation or responsibility, fairness, and general issues of equity between classes are includable issues."[6]

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[3] The $1.94 billion is in loaded and escalated nominal dollars. Of the $1.94 billion, approximately $1.67 billion is for SoCal Gas; the remaining $267.4 million is for SDG&E. (Ex. DRA-106, p. 1-2.) As of this writing, a Commission decision on the reasonableness and scope of Sempra's Phase 1A Plan costs is pending.

[4] Ex. DRA-5, p. 20, Table 6.

[5] See, e.g., *Opinion Regarding the Settlement of Phase Two Issues* (2009) D. 09-11-006.

[6] Scoping Memo, p. 9.

The Commission's guiding principles for allocation of natural gas pipeline transportation costs focus costs on cost causation, economic efficiency, and equity.[7] Foremost in cost allocation is the determination of what is driving the costs.[8]

The current cost allocation and rate design for the Sempra Utilities' gas transportation rates were settled in the 2009 Biennial Cost Allocation Proceeding (BCAP). The Commission adopted a settlement which used the embedded cost allocation method for the Sempra Utilities' transmission and storage facilities, and the long-run marginal cost allocation for the distribution facilities.[9] This is consistent with the cost allocation method adopted by the Commission when it approved settlements in the Pacific Gas and Electric Company (PG&E) Gas Transmission and Storage Services proceeding,[10] and in PG&E's Gas Distribution proceeding.[11] Most recently, in its Decision adopting a revenue requirement and cost allocation for PG&E's Pipeline Safety Enhancement Plan, the Commission followed that existing structure even though three parties, all representing large non-core customers, recommended that the Commission abandon the principles, and use instead an Equal Percent of Authorized Margin allocation.[12]

B. Cost Allocation Methodology for Pipeline Safety Enhancement Plan Costs

Cost allocation refers to "the process of determining the cost of each utility function and allocating these functions to the customer classes."[13] The costs at issue here are for testing and

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[7] See, e.g., *Order Instituting Investigation on the Commission's own Motion into Implementing a Rate Design for Unbundling Gas Utility Services Consistent with Policies Adopted in D.86-03-057* (1992*)* D.92-12-058, Conclusion of Law 2.

[8] 13 RT 2057, Sabino/ DRA.

[9] D.09-11-006, Appendix A, Settlement Agreement, Section II.B.2.

[10] *Decision Regarding the Gas Accord V Settlement* (2011) D.11-01-031.

[11] *Decision Concerning the Cost Allocation and Rate Design of the Previously-Approved Gas Distribution Costs* (2010) D.10-06-035.

[12] *Decision Mandating Pipeline Safety Implementation Plan* (2012) D.12-12-030, mimeo, p. 106. The three parties recommending the Commission abandon the functionalize approach in the PG&E case were the Northern California Indicated Producers, the Northern California Generation Coalition, and Dynegy.

[13] Ex. SCG-130, p. 2, lines14-16.

replacing all natural gas transmission pipeline segments that have not been pressure tested or where pipeline records have not been located.[14] Since it is the safe and reliable operation of the gas transmission and high pressure distribution pipeline functions that are driving the associated costs of the Plan, it is those functions that should be the basis of allocating Plan costs to customers.[15]

1. Equal Percent of Authorized Margin

Although Sempra used the functional approach for allocating non-Pipeline Safety Plan gas transportation costs, for purposes of allocating the Plan costs, Sempra proposes that the Commission use instead the Equal Percent of Authorized Margin ("EPAM"[16]) method. Use of the EPAM method would allocate about 95% of the Plan costs to the core classes of customers.[17]

Not surprisingly, all of the non-core customer classes participating in this Phase of the Proceeding favor Sempra's proposal or variations of it. The parties advocating allocation by Equal Percent of Authorized Margin give different, and sometimes contradictory, reasons.

For their part, the Sempra Utilities say that the Pipeline Safety Enhancement Plan costs "… should be allocated in a manner that, on a percentage rate impact basis, is relatively equitable across our different customer classes."[18] According to Sempra, "the EPAM method accomplishes this with rate impacts of approximately 11% to 13% to all classes."[19]

In a subsequent revised updated version of its PSEP allocation testimony, Sempra claims that during the four-year period of Phase 1A, most rates will increase by approximately 7% to

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[14] Scoping Memo, p. 3. See also, *Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans* (2011) D.11-06-017.

[15] *See* Ex. DRA-106, p. 1-19, lines 27-28.

[16] This method is also sometimes referred to as "Equal Percent of Allocated Margin. 12 RT 1748, Lenart/ Sempra.

[17] 10 RT 1681, lines 14-19, Morrow/ Sempra. "Core" customers include residential, small commercial and industrial, natural gas vehicles, gas air conditioning, gas engine. (See, e.g., Ex. SCG-35, p. X.C.3.)

[18] Ex. DRA-106, p. 1-21 citing Response of SoCalGas SDG&E to DRA DR PZS5, Q. 1.

[19] Ex. DRA-106, p. 1-21 citing Response of SoCalGas SDG&E to DRA DR PZS5, Q. 1.

14%.[20] Sempra thus equates an "equitable allocation" of Plan costs with Equal Percent of Authorized Margin, where SoCalGas and SDG&E transportation rates would purportedly increase by roughly equal percentages across all customer classes.[21]

But Sempra presents an incomplete picture. For one thing, the Pipeline Safety Plan costs are not the only rate increases Sempra's customers are likely to be facing this year, all effective January 1, 2013. There are the other non-Plan costs, also being considered in this Triennial Cost Allocation Proceeding, and then there are the rate increases that will result from the Commission's resolution of Sempra's General Rate Case applications.[22]

When the increases from using EPAM to allocate Sempra's Proposed Plan costs are considered along with the increases from Sempra's non-Plan TCAP, and with the increases Sempra asked for in its General Rate Case applications, the percentage rate impacts are nowhere near "equal." For SoCalGas, the combined percentage rate impact of the three rate cases could range from a negative 3.8% to a positive 32% across all the different customer classes.[23] For SDG&E, the combined percentage rate impact of the three rate cases could range from a negative 1.8% to a positive 53% across the customer classes.[24]

On May 9, 2013, the Commission issued its decision in the Sempra Utilities' General Rate Cases. In that decision, the Commission adopted a $123.379 million increase over 2012 present rates for SDG&E, and a $84.831 million increase over 2012 present rates for SoCal Gas.[25] The decision also provides for annual attrition increases of 2.65% in 2013, 2.75% in 2014, and 2.75% in 2015.[26]

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[20] Ex. SCG-130, p. 8. (Revised Updated Prepared Direct Testimony of G. Lenart dated 2/22/13).

[21] Ex. SCG-102, p. 1 (Rebuttal of R Morrow dated 12/14/2012).

[22] *See* A.10-12-005 and A.10-12-006.

[23] Ex. DRA-106, p. 1-6, Table 1-1, Column G.

[24] Ex. DRA-106, p. 1-6, Table 1-1, Column G.

[25] *Decision in General Rate Cases of San Diego Gas & Electric Company and SouthernCalifornia Gas Company (*2013) D. 13-05-010, mimeo, p. 2.

[26] *Decision in General Rate Cases of San Diego Gas & Electric Company and SouthernCalifornia Gas Company (*2013) D. 13-05-010, mimeo, p. 1011.

DRA recommends the Commission reject the Applicants' claim of "relative equity" as a basis for allocating Pipeline Safety Enhancement Plan costs[27] If the Commission is interested in considering the "relative equity" of all the rate increases facing Sempra's ratepayers, it should not confine its inquiry to this one part of this one case.

a) Cost Causation

In any event, in keeping with the Commission's cost allocation principles, cost responsibility should match cost causation.[28] Using the Equal Percent Authorized Margin allocator will not achieve that goal; using the functionalized approach will.

The Commission instituted the Pipeline Safety Enhancement Program "…to replace or pressure test all natural gas transmission pipeline in California that has not been tested or for which reliable records are not available."[29] This Program, arising from the missing records, is driven by the Commission's obligation "…to promote the safety, health, comfort and convenience of utility patron's, employees, and the public."[30]

The Equal Percent Authorized Margin method allocates costs according to each customer class' responsibility for the "base margin." Base margin and "authorized margin," for purposes of this case, mean the same thing.[31]

The "Authorized Margin" on which the EPAM method is based, however, is made up of a number of cost components that are not the subject of the proposed Pipeline Safety Enhancement Plan. For example, for the residential segment of Sempra's core customers, the "customer related costs" and "medium pressure distribution costs" make up about 85% of the Authorized Margin."[32] But neither of these components is driving the work contemplated by the Pipeline Safety Enhancement Plan. The Plan is not about meters, or call centers, or appliance

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[27] Ex. DRA-106, p. 1-24.

[28] Ex. DRA-106, p. 1-19.

[29] D.11-06-017, mimeo, p. 18.

[30] D.11-06-017, mimeo, p. 18.

[31] 12 RT 1798, Lenart/ Sempra.

[32] Ex. SCG-35, p. X.C.4.

service representatives, which are the functions included in customer costs.[33] Nor is the driver of the Plan costs Sempra's *medium* pressure distribution system. In fact, there are no Plan cost components associated with customer costs and medium pressure distribution system.[34] This Plan is to ensure the safety and reliability of Sempra's transmission and high pressure distribution systems, and the Plan costs should be allocated accordingly.

With different rationales, the Southern California Edison Company (SCE), the Southern California Indicated Producers and Watson Cogeneration Company (SCIP/Watson), and the Southern California Generation Coalition (SCGC) also advocate the use of the Equal Percent of Authorized Margin. At one extreme is SCIP/Watson, which argues that:

> [o]bviously, customers who live or work within the [Potential Impact Radius] of a gas transmission line will receive the direct benefits of enhanced safety, in terms of reducing their own risk of harm from a catastrophic pipeline accident.[35]

The basis for this argument is data from SoCalGas/ SDG&E 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."[36] From this, SCIP/ Watson concludes, "almost all of the direct safety benefits of the utilities' plans will accrue to core customers."[37]

SCIP/ Watson made the same argument, almost verbatim, in the PG&E Pipeline Safety Plan case.[38] The Commission did not adopt it there, and should not do so here.

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[33] 12 RT 1806, Lenart/ SCG.

[34] Ex. SCG-9, Table IX-1 and IX-2 listing "elements" of the Proposed Case Plan as: Pressure Testing, Pipe Replacement, In-Line Inspection, Interim Safety Enhancements, Remote Control & Automatic Shutoff Valves, Implementation Costs, Mitigation of Pre-1946 Construction Methods, Technology Enhancements, and Enterprise Asset Management System.

[35] Ex. SCIP-100, p. 15, Direct Testimony of R. Thomas Beach.

[36] Ex. SCIP-100, p. 15, Direct Testimony of R. Thomas Beach.

[37] Ex. SCIP-100, p. 15, Direct Testimony of R. Thomas Beach.

[38] Ex. DRA-112, excerpts from the "Prepared Direct Testimony of R. Thomas Beach on Behalf of the Northern California Indicated Producers," p. 15.

In this case, neither Sempra nor SCGC endorse the SCIP/Watson position. Sempra says that "[f]undamentally, all customers in our service territories will benefit equally from these investments in transmission pipeline safety."[39] As SCGC puts it, Backbone Transmission Service users "…get benefits associated with enhanced reliability that is associated with the PSEP system."[40] DRA agrees.

For its part, the City of Long Beach argues in favor of the Equal Percent of Marginal Cost Method saying that:

> If the rationale behind the investment was solely to increase deliverability and/ or reliability, then such allocators would likely be appropriate. However, the PSEP is not primarily intended to deliver more gas more reliably; pipeline safety is intended to protect life and property, and as such benefits all customers independent of usage.[41]

DRA disagrees with this characterization of the *intent* of the Pipeline Safety Plan, but if intent is a factor in determining cost causation, then it is the intent behind the project design criteria. As Sempra put it in its Opening Brief in Phase 1A of this case: "[a]ll of the work we propose to complete as part of our PSEP is designed to meet the higher safety and regulatory standards being established by the Commission and to enhance the safety *and reliability* of our transmission system for the benefit of our customers."[42]

DRA disagrees with all the arguments made by the non-core parties to separate the safety aspect from the functional operation of the pipelines. Operating the pipelines safely is integral to the functioning of the pipelines. Customers who are served by the pipelines should pay the costs for pipeline safety in the same way gas transportation costs are allocated.

SCE argues that the "functionalization method to allocate PSEP costs" is without merit, in part because the method "…is derived from a one-time, non-precedential settlement from SoCalGas' prior BCAP."[43] Certainly, the settlement is not precedent, but the Commission

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[39] Ex. SCG-101, p.22, lines 6-7, Amended Direct Testimony of R. Morrow.

[40] 13 RT 2033, lines 22-28, Yap/ SCGC.

[41] Ex. LB-101, p. 6.

[42] Sempra Opening Brief, October 19, 2012, p. 2, emphasis added.

[43] Ex. SCE-101, p. 6 (Rebuttal).

adopted its functionalized approach to gas transportation costs as reasonable in light of the record, the law and Commission policy. The "magnitude of proposed PSEP costs"[44] in this case does not make the functionalized approach to gas transportation rates here any less reasonable in light of the record, the law and Commission policy.

b) "Multiplier" Effect

SCIP/ Watson, SCE and SCGC also argue that adopting a functionalized allocation method will have a "multiplier effect…." that will lead to a windfall to some energy providers[45] and an unfair burden to ratepayers. This is not a new argument. In the PG&E Pipeline Safety case, the Northern California Independent Producers and the Northern California Generation Coalition made the same claim.

In the PG&E Pipeline Safety case, the Northern California Independent Producers estimated the multiplier effect of a direct increase in gas costs for electric generators on electric rates of 2.4 times.[46] In this case, the Southern California Indicated Producers estimate the multiplier effect at 2.3 times.[47] SCIP provides the same basic calculation in this case that it provided in PG&E's Pipeline Safety Plan case, but no supporting documentation to back up any of the underlying assumptions. If the purpose of SCIP's testimony is to show that authorizing Sempra ratepayer funding of the Sempra Proposed Plan will greatly increase rates to all customers, core and non-core, DRA agrees. But nothing in this "multiplier effect" argument justifies deviating from the basic cost causation principle that customers should pay for the service they receive.

SCE takes the multiplier argument one step further and claims that, if the cost of natural gas transportation increases the market price of electricity, then SCE's payments for renewable

[44] Ex. SCE-101, p. 7 (Rebuttal).

[45] Ex. SCE – 100, p. 5 (Direct).

[46] Ex. DRA-112, Prepared Direct Testimony of R. Thomas Beach on Behalf of the Northern California Indicated Producers, p. 19.

[47] Ex. SCIP-100, p. 18.

energy rise accordingly.[48] DRA has found nothing in SCE's testimony or exhibits that provides any factual support for this argument.

Presented with the same arguments in the PG&E Pipeline Safety Enhancement Plan case, the Commission declined to adopt them as a reason to apply an Equal Percent of Authorized Margin cost allocation.[49] The Commission should not adopt the EPAM method here, either.

c) Threat of Bypass

Like SCIP/ Watson, and Sempra[50], SCE claims that functionalizing the Pipeline Safety Plan costs "could" result in bypass on the Sempra transmission system which "… would just shift and increase PSEP costs to the customers who do not (or cannot) leave the system."[51] This conclusion assumes there are no additional customers coming onto the Sempra system[52], and there is no more evidence to support this conclusion than there is to show even one customer will leave Sempra's system to avoid the Pipeline Safety Plan charge.

In any event, "leaving the system" would likely involve incurring costs of building the lateral connections necessary to get direct service from interstate pipelines,[53] a fact which any departing customer is likely to consider. At this point, however, there is no evidence in the record of what those costs are, or how they would compare to possible increases in the Transmission Level Service.

Threats of bypass are not new. In fact, the Northern California Indicated Producers made this same argument, in almost exactly the same words, in PG&E's Pipeline Safety Plan case.[54] The Commission did not base any findings or orders in the PG&E case on the bypass argument. There is no factual basis in this case either for the Commission to place any reliance on the bypass argument.

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[48] Ex. SCE-100, p. 5.

[49] D.12-12-030, p. 106.

[50] Ex. SCG-102, p. 2.

[51] Ex. SCE-101, p.11, lines 26-27 (Rebuttal).

[52] 13 RT 2069-2070, Sabino/ DRA.

[53] 14 RT 2130, lines 21-28, Sabino/ DRA.

[54] Ex. DRA-112, p. 16.

d) "Rate Shock" to Non-Core Customers

In its testimony, SCE argues that the Commission's well-established goal of avoidance of rate shock is a reason the Commission should not adopt a functional approach to transmission rates for Transmission Level Service customers.[55] It appears from the line of questions California Manufacturers and Technology Association (CMTA) pursued in hearings that it, too, will argue that "rate shock" to non-core customers will result if the Commission uses a functionalized allocation. This is not necessarily true, or certainly no more true for non-core customers than core customers. In the words of the SCGC witness, "[a]llocation is a two-step process"[56]: the revenue requirement establishes the size of the pie, the combination of allocators decides size of the different slices.[57]

At this point, it is unknown what the Commission will ultimately decide is the appropriate revenue requirement amount to be allocated to Sempra's ratepayers. Certainly, the evidence in Phase 1A of this case shows that Sempra's "Proposed Case" revenue requirement is considerably overstated, both in terms of the total amount, and whether ratepayers or shareholders should bear the burden of it. To lessen the rate impact on any customer class, it may be that the Commission will decide to move to other phases of Sempra's PSEP some projects that are not as urgent as others.[58]

In any event, the 67% percentage increase[59] that SCE, CMTA and Sempra used as an example of the rate increase to Transmission Level Service customers does not include allocation to the Backbone Transmission Service.[60] When Backbone Transmission Service is allocated its share, the results to all other classes drop correspondingly. For the Transmission Level Service

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[55] Ex. SCE-xx, p. 3, lines 16-24.

[56] 13 RT 2036, lines 16-28, Yap/ SCGC.

[57] 13 RT 2036, lines 16-28, Yap/ SCGC.

[58] 14 RT 2131, lines 10-27, Sabino/ DRA.

[59] Ex. DRA-106, p. 1-22, Table 1-4, Column I; Ex. SCE-101, p. 11.

[60] *See, e.g.,* 14 RT 2129, lines 5-27, Sabino/ DRA.

customer using DRA's functionalized approach, that increase would actually be more like 16%.[61]

2. Functionalized Allocation Method

The "functionalized" allocation method apportions costs based on the function of the underlying asset. The function of the transmission pipeline system is to transport gas to the customers using the pipelines.[62] The "functionalized" cost allocation method is also referred to as the default allocation.

The default cost allocation filing in the SCG's Supplemental Testimony allocates transmission-related revenue requirement using cold-year peak month, while distribution-related revenue requirements are allocated using peak-month distribution throughput at SoCalGas and peak-day distribution throughput at SDG&E, consistent with authorized cost allocation method.[63] These default cost allocators are based on the marginal demand measures that the transmission and distribution functions on the utilities' systems are designed to serve.[64]

The utilities' systems are designed, constructed, and operated to meet customers' peak requirements, and therefore, should be allocated based on the customers' demand imposed on the system. This simply means that the demand driver causing the incurrence of Plan-related transmission costs on the SoCalGas and SDG&E local transmission systems is cold-year peak month while the demand driver causing the incurrence of Plan-related distribution costs on the SoCalGas high pressure system is peak-month distribution throughput and on SDG&E's is peak-day distribution throughput.

From information provided by Sempra, it is evident that, although the SoCalGas/SDG&E residential customers comprise 96.5% of the total combined customers their class is responsible for only 31.4% of the combined backbone and local transmission system demand on SoCalGas, and for only 32.9% of the system demand on SDG&E. The SoCalGas residential customer class is responsible for 60.9% of the high pressure distribution demand on the SoCalGas system, while

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[61] See Ex. SCG-136, Column L, which uses the functionalized method, including allocation to the backbone, but with high pressure distribution allocated at peak-month demand (the standard allocation method for the distribution function).

[62] Ex. DRA-107, p. 6.

[63] Ex. DRA-106, p. 1-17 citing Response of SoCalGas SDG&E to DRA DR PZS1-1b.

[64] *See* D.92-12-058 in which the Commission first adopted marginal demand measures.

the SDG&E residential class is responsible for 67.2% of the high pressure distribution demand on the SDG&E system.[65]

The EPAM allocators, on the other hand, are dictated by a predominant group of costs that has less to do with the way customers use gas transmission pipeline and high pressure distribution, and more to do with customer costs and medium pressure distribution costs. This is clearly inconsistent with the principles of cost causation that is used to establish cost of service.

Cost responsibility should match cost causation. It would be inappropriate to attribute the cost causation for the transmission Plan to both the customer costs and the medium pressure distribution costs which comprise the bulk percentage of the total allocated base margin. The customer costs and the medium pressure distribution costs are not the drivers of the costs of the underlying Plan transmission and high pressure distribution assets. Using the proposed EPAM allocators would distort cost allocation and result in the vast majority of the Pipeline Safety Enhancement Plan revenue requirements being allocated to residential customers.

As discussed above, the Plan itself is transmission-related, not customer-cost-related. The costs of the Plan should be allocated with those drivers in mind.[66]

3. Other

DRA has no other issues to raise at this time.

C. Allocation to Backbone Transmission Service

In response to a Ruling from the Assigned Commissioner, Sempra prepared an exhibit showing Applicants' Proposed Case Plan costs allocated by function. Sempra's exhibit with the functionalized cost allocation did not, however, allocate any PSEP costs to the backbone transmission function.[67]

As SCGC points out:

> [t]he applicants make a serious omission in developing their EPAM allocation. They exclude the [Backbone Transmission Service] from the allocation.[68]

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[65] Ex. DRA-106, p. 1-18.

[66] Ex. DRA-106, p. 1-Response from SoCalGas SDG&E to DRA DR PZS-02 Question 4.

[67] Ex. DRA-106, p. 1-11, lines 21-23

[68] Ex. SCGC-100, p. 4.

DRA agrees. The costs of the backbone transmission function should be allocated to customers using that specific pipeline function.

In its testimony, Sempra gave two reasons for excluding Backbone Transmission Service from the allocation of Pipeline Safety Costs. The first was that the backbone transmission embedded costs were specified in the Commission's April 2011 decision on Firm Access Rights.[69] The second reason was that when Sempra provided its "functionalized" cost allocation, it only proposed collecting Pipeline Safety Plan costs from end-use customers "…because the end-use customers are the ones who mainly benefit from the PSEP."[70] In hearings, Sempra's witness testified that:

> "[e]nhanced safety does not increase the value of the backbone system to customers in terms of added capacity, and therefore from a position of cost causality, none of these arguments has merit.

The Firm Access Rights decision was issued before Sempra introduced its Pipeline Safety Enhancement Plan so, obviously, the costs of the Proposed Plan were not considered.

Sempra's determination that "end-use customers are the ones who mainly benefit from the PSEP" is also flawed. All customers who use Sempra's transmission service benefit from the safe and reliable operation of that service. As SCGC's witness testified, Sempra's pipeline safety enhancement program: "… is jointly a safety issue and a reliability issue. Anyone who suffered from the pipeline explosion on the El Paso system a decade ago can remember the kind of disruption there was to the gas markets…. There is a benefit to users from having enhanced reliability."[71]

Finally, Sempra's argument that the functional allocation "would be appropriate with costs caused with the intention of increasing the capacity or reliability of the system" but not when the essential performance of the pipelines will remain the same,"[72] is undercut by

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[69] *Decision Addressing Application of SDG&E and SCG Updating Firm Access Service and Rates* (2011) D. 11-04-032.

[70] Ex. DRA-106, p. 1-11, lines 23-25, citing telephone conversation with SCG witness G. Lenart.

[71] 13 RT 2034, lines 5-13, Yap/ SCGC.

[72] Ex. SCG-133, p. 3, lines 7-10, Rebuttal.

Sempra's own Plan. Sempra's Proposed Plan includes projects to add new segments to some pipelines in and increase diameters of others.[73]

IV. PIPELINE SAFETY ENHANCEMENT PLAN RATE DESIGN

A. Line Item Surcharge

DRA does not oppose Sempra's proposal to show the PSEP Surchage as a separate line item on the customer bill. DRA recommends, however, that the rate be based on the functionalized cost allocation method as described above. DRA also recommends that the charge be on a volumetric basis using the "new customer only" method.[74]

B. Fixed or Volumetric Surcharge

Applicants ask the Commission to authorize a fixed monthly PSEP charge for residential customers, as opposed to a volumetric charge for non-residential customers.[75] DRA disagrees. DRA recommends a volumetric charge for residential customers also.

A fixed charge means that even customers who participate in energy efficiency programs and reduce their consumption would pay the same as customers who do not.[76] This runs counter to California's long-standing policies of conservation and environmental responsibility. Pipeline Safety Enhancement Plan charges for both residential and non-residential customers should be volumetric.

V. CUSTOMER CHARGE FOR SDG&E RESIDENTIAL NATURAL GAS CUSTOMERS

DRA has no comment on this issue at this time.

VI. UNCONTESTED PROPOSALS

DRA has no comment on these proposals at this time.

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[73] SoCal Gas Distribution Line 38-959(from 6.25" to 12.75"), Line 38-539 (6.25" and 8.825" to 10.75"), Line 41-6000-2, and Line 6914, 8 RT 1391-1392, Bisi/ Sempra; Ex. SCG-32, Amended Workpapers, pp. WP-IX-1-B136 to B 138; WP- IX-B129 to B130. *See also* DRA Opening Brief, pp. 40-42.

[74] Ex. DRA-106, p. 1-27.

[75] Ex. SCG-26, p. 8. (Reyes)

[76] 12 RT 1862, Lenart/ SCG.

VII. CONCLUSION

For all the foregoing reasons, DRA asks that its recommendations, set forth in testimony and in this Brief be adopted.

Respectfully submitted,

/s/ Laura Tudisco

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May 24, 2013

ATTACHMENT D

ORA EXHIBIT 20 IN A.13-12-012

Exhibit No. ___________
Date: November 16, 2012
Witness: R. Thomas Beach

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for Authority To Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding.	A.11-11-002 (Filed November 1, 2011) **PHASE 2**

PREPARED DIRECT TESTIMONY OF R. THOMAS BEACH

ON BEHALF OF

THE SOUTHERN CALIFORNIA INDICATED PRODUCERS

AND

WATSON COGENERATION COMPANY

November 16, 2012

Crossborder Energy

BEFORE THE
PUBLIC UTILITIES COMMISSION
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STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for Authority To Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding.	A.11-11-002 (Filed November 1, 2011) **PHASE 2**

PREPARED DIRECT TESTIMONY OF R. THOMAS BEACH ON BEHALF OF THE SOUTHERN CALIFORNIA INDICATED PRODUCERS AND WATSON COGENERATION COMPANY

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 213A, 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 Southern California Indicated Producers (SCIP) and Watson Cogeneration Company (Watson). For the purposes of this proceeding, the members of SCIP include ConocoPhillips Company, Chevron U.S.A. Inc., and Exxon Mobil Gas Corporation. The members of SCIP 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 Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) service territories.[1]

Watson owns and operates a single 400 MW cogeneration plant located in Carson, California. Southern California Edison Company (Edison) purchases 340 MW of Watson's electric generating capacity. The remainder of Watson's electrical capacity, and the facility's steam output, are sold to BP's Carson Refinery. Watson receives intrastate gas transportation services from SoCalGas, and is the largest cogeneration facility served from the SoCalGas system. Watson has been in commercial operation since 1988, and since that time has participated actively before this Commission on many issues concerning SoCalGas' natural gas transportation rates and services.

Q: What is the scope of this phase of the SoCalGas / SDG&E TCAP?

A: Phase 2 of this Triennial Cost Allocation Proceeding (TCAP) will consider cost allocation and rate design issues for SoCalGas and SDG&E (also, "the Sempra gas utilities"). These issues include the allocation and rate design for the potentially significant new costs associated with the pipeline safety enhancement plan (PSEP) which SoCalGas and SDG&E filed in Rulemaking (R.) 11-02-019 in August 2011. The Sempra gas utilities filed their PSEP in response to the Commission's Decision (D.) 11-06-017. The Commission issued this decision in the pipeline safety rulemaking (R. 11-02-019) which the Commission initiated in the aftermath of the tragic pipeline explosion in September 2010 on Pacific Gas & Electric Company's (PG&E) gas pipeline system in San Bruno, California. Subsequently, in D. 12-04-021, the Commission determined that the SoCalGas / SDG&E PSEP should be reviewed in this TCAP case. Phase 1 of this TCAP examined most issues concerning the merits of the PSEP, but left cost allocation and rate design issues for Phase 2.

Q: What are the interests of SCIP and Watson in this phase of the TCAP?

A: The operations of SCIP members and Watson will be affected by the possible large rate

[1] This testimony refers to SoCalGas and SDG&E collectively as "the Sempra gas utilities."

increases and potential service disruptions that may result from the SoCalGas / SDG&E PSEP. Accordingly, SCIP members and Watson have a strong interest in the PSEP-related issues that the Commission is considering in both phases of this TCAP, including the cost allocation and rate design issues in Phase 2.

Q: Did you testify on behalf of SCIP and Watson in Phase 1 of this TCAP?

A: Yes, I did. On June 19. 2012, I served Phase 1 testimony on behalf of SCIP and Watson. My Phase 1 testimony addressed the significant impacts on noncore customers that may result from the large rate increases that SoCalGas and SDG&E are seeking in order to recover the proposed costs of the PSEP. I also testified on the design of the balancing account that will be used to track PSEP costs and revenues, on the possible duplication of costs between the PSEP and the utilities' existing pipeline safety programs, on shareholder responsibility for certain PSEP costs, and on measures to reduce the potential disruptions in gas service that may result from PSEP work on the Sempra utilities' gas transmission facilities.

I. SUMMARY AND RECOMMENDATIONS

Q: Please summarize the principal recommendations of your testimony.

A: My testimony makes the following key recommendations on cost allocation and rate design issues associated with the SoCalGas / SDG&E PSEP:

- The Commission should adopt the Sempra utilities' proposal to use the Equal Percent of Authorized Margin (EPAM) approach to allocate any PSEP costs which the Commission's Phase 1 decision allows to be recovered in rates.

- The use of EPAM will result in an equitable allocation of PSEP costs, with all customer classes receiving approximately an equal percentage increase in their transportation rates.

- EPAM is preferable to the use of the allocation of local transmission and high pressure distribution costs which the Commission adopted in the last SoCalGas / SDG&E Biennial Cost Allocation Proceeding (BCAP). The BCAP cost allocation, when applied to proposed PSEP costs, would result in transportation rate increases by 2015 in excess of 80% for large industrial and electric generation customers. Rate increases of this magnitude would:

- o Encourage large customers to bypass the Sempra utilities' gas systems, either through direct connections to interstate pipelines or through "bypass-by-wire" in which electric generation loads move to power plants with access to less expensive gas transportation service.

- o Adversely impact trade-sensitive California industries.

- o Result in electric rate increases that would be more than twice as large as the direct increase in gas transportation costs.

- The EPAM approach also makes sense because it allocates PSEP costs to core customers in proportion to the direct safety benefits which those customers receive from the PSEP.

- On rate design, a separate surcharge should be used to recover authorized PSEP costs. A separate surcharge appropriately recovers PSEP costs directly from all end-use customers and facilitates the necessary tracking and segregation of these costs.

II. BACKGROUND ON THE SOCALGAS – SDG&E PSEP

Q: Please discuss the origin and purposes of the safety-related issues under consideration in this proceeding.

A: The Commission issued Rulemaking (R.) 11-02-019 in response to the tragic gas pipeline explosion on September 9, 2010 on the PG&E system in San Bruno, California. R. 11-02-019 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 using "traceable, verifiable, and complete" records, 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.[2]

Q: What purposes are the pipeline safety implementation plans meant to serve?

A: On June 9, 2011, the Commission issued D. 11-06-017 in the pipeline safety rulemaking R.11-02-019. This decision directed each of the state's regulated gas utilities to file an Implementation Plan describing how each utility would "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.[3] In D. 12-04-021, the Commission transferred the examination of the SoCalGas / SDG&E PSEP to this TCAP proceeding.

Q: Has the Commission identified how implementation plan costs will be recovered in rates as an important factor in evaluating the gas utilities' pipeline safety plans?

A: Yes, it has. 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."[4] In this TCAP case, the Scoping Ruling clearly puts all "cost allocation and rate design" issues related to the PSEP into Phase 2, except for the allocation of pipeline safety costs between ratepayers and shareholders, which is in Phase 1.[5]

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2 In addition, with respect to PG&E alone, R. 11-02-019 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. In addition, the Commission has instituted companion OIRs on issues concerning PG&E's record-keeping for its pipeline system (I. 11-02-016), on issues concerning the class location of transmission pipelines (I. 11-11-009), and on the San Bruno accident itself (R. 12-01-007). Finally, the Commission 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).

3 D. 11-06-017, at 19-20.

4 *Ibid.*,at 22.

5 *See* "Assigned Commissioner's Scoping Memo and Ruling" (Scoping Ruling), dated February 24, 2012 in this docket, at 5.

Q: Should the Commission consider ratepayer impacts in evaluating the SoCalGas / SDG&E pipeline safety plan?

A: Yes, it is important for the Commission to consider the economic impact of the SoCalGas / SDG&E PSEP on the utilities' customers. In the aftermath of the tragic San Bruno pipeline explosion, there is no question that the Commission's efforts to place a higher priority on pipeline safety are justified and needed. At the same time, the plans provide the 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 both gas and electric ratepayers. Notably, 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.*[6]

Accordingly, the Commission must ensure that the magnitude, the priority, and the pace of SoCalGas' and SDG&E's proposed safety-related spending are reasonable. Importantly, in addition to undertaking unprecedented levels of spending, the outlays will take place over a very compressed time frame. This acceleration of spending will impose cost premiums on ratepayers when compared to a more measured and consistent investment in safety-related improvements. The magnitude, pace, and scope of PSEP spending, as well as the allocation of PSEP costs between ratepayers and shareholders, are Phase 1 issues. Phase 2 concerns how approved PSEP costs will be allocated to customer classes and then recovered through rates. As discussed in this testimony, Phase 2 issues also will have a significant impact on the ratepayers of the Sempra utilities.

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[6] P.U. Code Section 963[b][4].

III. ENHANCING 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 be on cost-effective safety improvements. 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 am confident that, in Phase 1, the Commission will review the SoCalGas / SDG&E PSEP carefully, to ensure that the Sempra gas utilities have thoroughly justified their proposed safety-related improvements and the associated expenditures.

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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. The Rate Changes Proposed By SoCalGas / SDG&E Are Significant.

Q: Would the SoCalGas / SDG&E PSEP result in substantial rate increases for natural gas customers in southern California?

A: Yes. SoCalGas and SDG&E propose to spend almost $1.7 billion in 2011-2015 to implement Phase 1A of their PSEP.[8] By 2015, these expenditures would result in rate increases in excess of 10% for many SoCalGas / SDG&E customers, both core and noncore.[9] For the purposes of comparison, **Tables 1 and 2** compare the proposed rate increases resulting from the Proposed Case PSEP expenditures to the SoCalGas / SDG&E transportation rate changes that core and noncore customers have experienced over the past three years (2009-2012). For SoCalGas, core and noncore transportation rates have grown by 4.1% and 4.2% per year over the last three years.

Table 1: Historical SoCalGas and SDG&E Transportation Rate Increases

Effective Date	Average Core Rate		Average Retail Noncore Rate	
	$/th	*Annual % Increase*	*$/th*	*Annual % Increase*
SoCalGas				
Jan 1 2009	0.4187		0.03693	
Jan 1 2012	0.4718	*4.1%*	0.04176	*4.2%*
SDG&E				
Jan 1 2009	0.5555		0.03454	
Jan 1 2012	0.4606	*-6.1%*	0.03737	*2.7%*

Source: SoCalGas and SDG&E advice letter filings. Rates include transportation, FAR / BTS costs, and unbundled fuel charges. SDG&E's core transport rate dropped significantly (-12%) at the end of 2011 (Advice Letter 2082-G) as a result of balancing account overcollections and the removal of advanced metering costs, resulting in the anomalous decrease in SDG&E's core transport rate.

From 2011-2015, the proposed PSEP generally would, using the proposed SoCalGas / SDG&E costs and cost allocation, increase this rate of growth by an additional 2.5% to

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8 SoCalGas / SDG&E PSEP Amended Testimony, at Tables IX-1 and IX-2. The utilities' testimony also includes a "Base Case" PSEP which only includes the work required under D.11-06-017, without the additional safety-enhancing elements proposed by SoCalGas and SDG&E that are not required under that decision. The Base Case revenue requirements and rates in 2015 are about 15% - 20% lower than the utilities' recommended PSEP proposal. *See* SoCalGas / SDG&E PSEP Amended Testimony, at Tables IX-3 and IX-4 for Base Case costs.

9 *Ibid.*, at Table X-13.

3.3% per year for most classes of customers.[10]

Table 2: Proposed PSEP Phase 1A Transportation Rate Increases

Effective Date	Residential	Core Commercial	Noncore C&I	TLS
	$/month	*$/th*	*$/th*	*$/th*
SoCalGas				
2011	21.57	0.373	0.100	0.016
2015	24.56	0.411	0.112	0.018
Total % Increase	*13.9%*	*10.1%*	*11.8%*	*11.5%*
Annual % Increase	*3.3%*	*2.5%*	*2.9%*	*3.0%*
SDG&E				
2011	23.60	0.360	0.259	0.016
2015	26.59	0.398	0.271	0.018
Total % Increase	*12.7%*	*10.6%*	*4.7%*	*11.6%*
Annual % Increase	*3.0%*	*2.5%*	*1.1%*	*3.0%*

Source: Amended SoCalGas / SDG&E PSEP Testimony, Table X-13 and Appendix I.

Q: What accounts for the significant rate increases that the PSEP would produce?

A: The PSEP would result in a substantial increase in the Sempra gas utilities' capital expenditures related to pipeline safety. **Figure 1** shows SoCalGas' and SDG&E's historical total and safety-related capital expenses from 2004-2010, as well as the utilities' forecasted future capital costs from 2011-2015, including the proposed PSEP. The figure shows that the PSEP will increase the utilities' capital spending significantly, with the PSEP alone more than doubling the utilities' capital budgets by 2015.

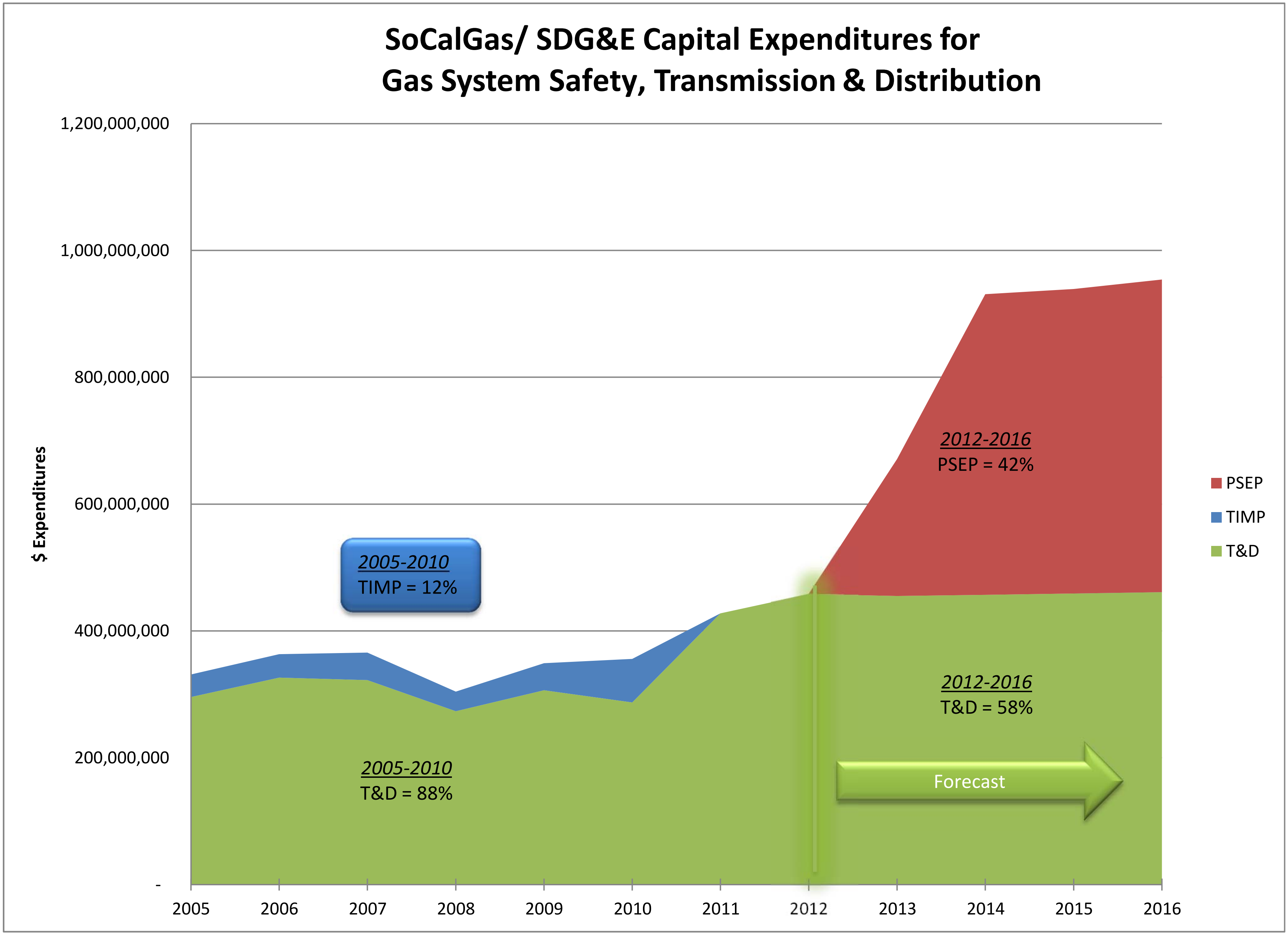
B. The Proposed Allocation of PSEP Costs Among Customer Classes

Q: How do SoCalGas and SDG&E propose to allocate PSEP costs among their customer classes?

A: SoCalGas and SDG&E propose to allocate PSEP costs using an equal percent of authorized margin (EPAM) methodology. 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. The result of the EPAM allocation is that

[10] **Table 2** is based on the rates in Appendix I of the SoCalGas / SDG&E PSEP Amended Testimony.

Figure 1



Crossborder Energy

SoCalGas' transportation rates would increase by roughly equal percentages across all customer classes. As shown in Table 2, these increases for most customer classes would average in the fairly narrow range of 2.5% to 3.3% per year from 2011 – 2015, assuming that the Commission authorizes the full amount of PSEP spending that the utilities have requested.

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."[11] EPAM is also the mechanism which the Sempra utilities use to allocate cost changes that occur and are placed into rates between cost allocation proceedings.[12] A similar method, the System Average Percentage Change (SAPC) approach, is widely used on the electric side to modify rates between GRCs.[13] The SAPC approach changes each classes' allocated revenue requirement by the same percentage that the system average rate changes.

Q: Do SCIP and Watson agree with SoCalGas / SDG&E's proposed use of EPAM?

A: Yes.

Q: Why do SCIP and Watson support the proposed use of EPAM?

A: First, an EPAM allocation is an appropriate allocation until PSEP costs can be reviewed in more detail and in a comprehensive fashion in the next SDG&E / SoCalGas GRC. The Division of Ratepayer Advocates (DRA), the Utility Reform Network (TURN), the Southern California Generation Coalition (SCGC) and SCIP/Watson have raised

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[11] SDG&E/SoCalGas Amended PSEP Testimony, at 22, line 10.

[12] *Ibid.*,at 22, footnote 17.

[13] For example, in Southern California Edison's last three GRCs (A. 11-06-007, A. 08-03-002, and A. 05-05-023), the parties have agreed in settlement that revenue requirement changes between GRCs should be allocated to customer classes on the basis of SAPC. The Commission approved the settlements in A. 08-03-002 and A. 05-05-023; the settlement in A. 11-06-007 is pending.

questions in Phase 1 concerning the adequacy of the utilities' showing that their requested scope and level of PSEP spending is justified. Until the next SoCalGas / SDG&E GRC, Phase 1 PSEP costs may receive final approval and be placed into rates in a piecemeal fashion, using processes such as separate expedited applications (SCGC's Phase 1 proposal[14]) or after-the-fact reasonableness reviews (TURN's Phase 1 proposal[15]). There is unlikely to be an opportunity for a comprehensive review of the PSEP costs until the next SoCalGas / SDG&E GRC or of cost allocation until the next TCAP. SCIP / Watson thus believe that it makes sense to use EPAM to allocate the PSEP costs that the Commission's Phase 1 decision or subsequent proceedings allow to be placed into rates in the interim before the next SoCalGas / SDG&E GRC. After a comprehensive review of the overall level of PSEP spending in the next GRC, cost allocation issues related to the PSEP could be considered again in the next TCAP case for that TCAP period. EPAM (for the Sempra gas utilities) and SAPC (on the electric side) are appropriately used to allocate other types of base revenue requirement changes that are placed into rates between GRCs.

More importantly, an EPAM allocation is more equitable than other allocation approaches and would not lead to dramatic cost shifts or large rate increases for any class of customers.

Q: What other approach to the allocation of PSEP costs is in the record?

A: The November 2 Amended Scoping Memo directed the utilities to show the rate impacts of the PSEP on their various customer classes if the allocation of PSEP costs, and the design of rates to recover such costs, were to follow the same approach used in the last SoCalGas / SDG&E biennial cost allocation proceeding (BCAP). This approach would allocate PSEP local transmission and high pressure distribution costs using the adopted allocators for local transmission (cold-year, peak-month throughput) and high pressure distribution (distribution-level peak day throughput). Such an allocation would result in a dramatic shift in PSEP costs to noncore customers, compared to the allocation that the

[14] SCGC Phase 1 Opening Brief, at 28-36.
[15] TURN Phase 1 Opening Brief, at 85-86.

utilities have proposed. Table 3 shows the annual rate increases that would result from allocating PSEP costs using the cost allocation from the last BCAP.

Table 3: Proposed PSEP Phase 1A Transportation Rate Increases, Using 2008 BCAP Cost Allocation

Effective Date	Residential	Core Commercial	Noncore C&I	TLS
	$/month	*$/th*	*$/th*	*$/th*
SoCalGas				
2011	21.57	0.373	0.100	0.016
2015	23.40	0.409	0.126	0.029
Total % Increase	*8.5%*	*9.7%*	*26.2%*	*80.9%*
Annual % Increase	*2.1%*	*2.4%*	*6.0%*	*16.0%*
SDG&E				
2011	23.60	0.360	0.259	0.016
2015	26.10	0.408	0.276	0.029
Total % Increase	*10.6%*	*13.3%*	*6.4%*	*80.9%*
Annual % Increase	*2.6%*	*3.2%*	*1.6%*	*16.0%*

Source: Amended SoCalGas / SDG&E PSEP Testimony, Table X-13 and Appendix I, plus Supplemental Testimony of Gary Lenart (December 2, 2011) at Table 1.

Table 3 shows that the BCAP cost allocation would result rate increases from 2011 to 2015 of over 80% (16% per year) for the largest noncore industrial and electric generation customers who take service under the TLS rate schedule, and rate increases from 2011 to 2015 of 26% (6% per year) for smaller noncore C&I loads on the SoCalGas system. These increases are far larger, in percentage terms, than the increases that core customers would face under this allocation method; Table 3 shows that increases for core customers would be in the range of 2.1% to 3.2% per year from 2011 - 2015.

Q: Why do the Sempra utilities believe that the use of the EPAM allocation method is justified?

A: The utilities 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); indeed, 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 BCAP cost allocation would result in very large rate increases for noncore customers. The Sempra utilities state that this "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."[16]

Q: Do you agree that the noncore rate increases that could occur under the BCAP cost allocation would increase the risk of noncore customers bypassing the Sempra utilities' gas systems?

A: Yes, I do. A significant 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 4**. The table shows that noncore gas use in southern California on the SoCalGas / SDG&E systems actually has declined by 7% from 1999 to 2010, while gas demand served from non-utility pipelines has grown by 22%:

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16 SDG&E/SoCalGas Amended PSEP Testimony, at 22-23.

17 *See* the California Energy Commission power plant licensing data base, at http://www.energy.ca.gov/sitingcases/all_projects.html#approved . Combined-cycle plants with gas service from interstate pipelines or California production include Sunrise, LaPaloma, Elk Hills, Blythe, High Desert, and 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.

Table 4: *Annual Noncore Gas Use (MMcf/d), from* **California Gas Report** *Data*

Serving Gas Utility / Pipeline	**1999 2010**		***Change***
PG&E	1,265	1,337	*+6%*
SoCalGas-SDG&E	1,329	1,232	***-7%***
Non-utility pipeline	1,098	1,341	***+22%***
Total Noncore	3,692	3,910	*+6%*
Non-utility as a % of Total	**29.7% 34.3%**		

The trend depicted in Table 4 will only accelerate if noncore transportation rates on the SoCalGas and SDG&E systems in southern California increase by over 80% to fund safety improvements, while the rates on competing interstate pipelines do not see comparable safety-related increases. The Commission should be concerned with the long-term impact on gas utility rates from such bypass. I observe that bypass of the utilities' systems can increase without customers physically migrating to interstate service: for example, "bypass by wire" can occur as gas throughput shifts to electric generators supplied from interstate or non-utility pipelines where gas transportation costs are less expensive. Such shifts will occur as the generators connected to low-cost gas systems capture a greater share of the competitive market for gas-fired electric generation in California.

At the same time, new safety surcharges will increase costs for electric generators who are "captive" to the SoCalGas / SDG&E systems. These generators will tend to be the highest-cost, marginal sources of electric generation, and thus will set the market-clearing price for gas-fired electricity. As a result, the safety surcharges will raise electric market prices and retail electric rates, an impact which I will discuss in more detail below.

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

A: Yes. First, data from SDG&E / SoCalGas clarify 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.[18] 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 catastrophic pipeline incident. This data demonstrates that almost all of the direct safety benefits of the utilities' plans will accrue to core customers. The EPAM methodology would allocate 93% of PSEP costs to core customers;[19] thus, the customer classes which receive most (97%) of the direct safety benefits from the PSEP would also pay the bulk (93%) of PSEP costs. It is also reasonable that all customers, including noncore customers, should contribute to paying PSEP costs, because all customers will realize the indirect benefits of these safety improvements, in the form of a more robust and resilient gas system that has a reduced risk of safety-related interruptions. An EPAM allocation achieves both goals – all customers make roughly an equal percentage contribution to PSEP costs, with core customers paying the bulk of PSEP costs in dollar terms because they receive most of the direct safety benefits of the program.

Second, the alternative to EPAM – the BCAP cost allocation – would result in an 80% increase in the TLS transportation rate paid by large electric generators in southern California. An increase of this magnitude would have a significant impact on energy-intensive, trade-exposed industries in California. The PSEP rate increases proposed for TLS rates under the BCAP cost allocation ($0.13 per MMBtu) are comparable to an increase in greenhouse gas allowance costs of $2.40 per tonne. Importantly, concerns about GHG allowance costs 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. In effect, CARB has expressed concerns that significant California-specific cost increases for EITE entities as a result of its GHG regulations could lead to a significant loss in economic activity to competitors outside of the state and to a shift in emissions out of the state (known as "leakage"). Stated simply,

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18 *See* SCG-SDG&E response to Watson-SCIP Data Request No. 1, Questions 5-6, which are included in **Attachment RTB-2**.

19 Based on SoCalGas / SDG&E PSEP workpapers, file "Assumptions – Safety OIR.xls," tab "Workpapers – Proposed Case," column C, rows 19-22, showing the EPAM allocation to the core.

regulators are concerned that significant increases in energy costs will cause industries to move out of the state. To forestall such leakage, CARB plans to allocate free emission allowances to EITE industries. Many of these same EITE industries will be impacted by pipeline safety transportation rate increases. Trade exposure also should be considered in this proceeding when cost allocation mechanisms are evaluated.

Third, the BCAP allocation of PSEP costs would significantly compromise the ability of EG customers on the Sempra system to compete in the electric market. Natural gas comprises almost all of the variable costs of a gas-fired generator. The BCAP allocation would increase the Sempra TLS rate for large EG customers by $0.13 per MMBtu by 2015, an increase of over an 80%. Based on current gas commodity prices and transportation rates, the BCAP allocation would increase the burnertip gas costs of SoCalGas and SDG&E EG customers by $0.11 per MMBtu (3%) compared to an allocation based on EPAM.[20] Such cost increases would put generators on the Sempra 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 Sempra 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 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

[20] Based on a SoCalGas City-gate price of $4.00 per MMBtu, a TLS rate of $0.29 per MMBtu, and the municipal surcharge of $0.03 per MMBtu.

statewide generation).[21]

- The California electric utilities import significant amounts of power from out-of-state sources. For example, according to CEC data, in recent years the state has imported about 30% of its power from out of state.[22] 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)[23] – 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.[24] The current SRAC energy pricing formulas explicitly include the SoCalGas-SDG&E tariffed EG transportation rates.[25] 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 SoCalGas-SDG&E gas surcharges will increase EG transportation rates for local transmission-level EG customers by an additional $0.11 per MMBtu. EG

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21 *See* detailed CEC electric generation data by source: http://energyalmanac.ca.gov/electricity/electricity_generation.html .

22 *Ibid.*, also CEC power source data, http://energyalmanac.ca.gov/overview/energy_sources.html .

23 *Ibid.*

24 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.

25 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.

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 $58 million per year.[26] An increase of $0.11 per MMBtu in the cost of marginal electric generation with a market heat rate of 7,500 Btu per kWh[27] will raise electric market prices by about $0.83 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 $0.83 per MWh times 160,000 GWh per year, or $132 million per year. This is about **2.3 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.

C. Rate Design for the PSEP Surcharge

Q: Do you support the separate surcharge for PSEP costs which the Sempra utilities propose?

A: Yes, for several reasons.

First, and foremost, enhancing the safety of the Sempra utilities' systems will benefit all end-use natural gas customers in southern California. As discussed above, the direct safety benefits – in terms of a lower risk of catastrophic accidents – accrue principally to the core end-use customers who live and work near transmission pipelines, while all end users will realize the benefits from a more reliable gas system. Given the safety and reliability benefits that end-users will realize, it is reasonable to recover

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

27 The 2012 market heat rate for SP-15 projected using forward market prices sampled in each month of 2010-2011 averaged 7,531 Btu per kWh. Actual 2012 SP-15 market heat rates to date have been much higher than this value as a result of the lengthy outage at the San Onofre nuclear power plant.

directly from end-users those PSEP costs that the Commission finds should be recovered in rates.

Second, a separate PSEP surcharge makes sense as a result of the extraordinary nature of these safety-related costs, the public attention to these issues, and the potential need for ongoing tracking of these costs separately from the Sempra utilities' other gas transmission and distribution costs. If these costs were to be integrated into the existing rate design for TLS customers, for example, significant additional effort could be required to segregate PSEP costs from regular system costs and to identify and design a separate PSEP component of each rate component in the TLS rate design, which includes both fixed reservation and volumetric components.

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

SoCalGas - SDG&E Responses

to Selected Data Requests

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