Application No.:	11-11-002
Exhibit No.:	R. Morrow
Witnesses:	D. Montgomery
	G. Tenley, Jr.
	L. Stewart
	M. Rosenfeld
	D. Schneider
	H. Haines
	R. Phillips
	D. Buczkowski
	D. Bisi
	J. Rivera
	J. Dagg
	S. Watson
	E. Reyes

(U 904-G) and (U 902-M)

REBUTTAL TESTIMONY OF SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF PROPOSED NATURAL GAS PIPELINE SAFETY ENHANCEMENT PLAN

Before the

Public Utilities Commission of the State of California

July 18, 2012

SOUTHERN CALIFORNIA GAS COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
PIPELINE SAFETY ENHANCEMENT PLAN
REBUTTAL TESTIMONY

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CHAPTER 1

POLICY

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PREPARED REBUTTAL TESTIMONY

OF RICK MORROW

My name is Richard Morrow. I am the Vice President of Engineering and Operations Staff for Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E). I sponsored opening testimony in this proceeding and my qualifications can be found in that volume.[1] Although I offer short comments on mitigating customer impacts from our Pipeline Safety Enhancement Plan, the principal purpose of my rebuttal testimony is to respond on a policy level to several witnesses testifying on behalf of the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Southern California Generation Coalition (SCGC), and Southern California Indicated Producers/Watson Cogeneration (SCIP/Watson) regarding the lack of pressure test records for some pipelines. These witnesses, to varying degrees, all argue that costs of pressure testing and pipeline replacement might have been avoided had such documents existed and therefore the costs should be borne by shareholders rather than ratepayers. This proposed cost shifting recommended by DRA, for example, amounts to just over $1.6 billion.

Mr. Beach, representing SCIP/Watson, suggests that our Pipeline Safety Enhancement Plan is needed because of years of "under investment in safety" and its compressed time schedule provides a higher return to shareholders than if the same work were spread over a 15 year rather than a 4 year period. The notion that there has been an under investment in safety is without merit and should be rejected by the Commission. These planned pressure tests and replacements are due to *new requirements* from the Commission. There was no existing pipeline safety

[1] I am also adopting the opening testimony of Mike Allman.

program at SoCalGas or SDG&E that obtained ratepayer funding in the past for such tests and replacements, which SoCalGas and SDG&E then failed to carry out.

SoCalGas and SDG&E developed our Pipeline Safety Enhancement Plan to accomplish the Commission's stated goal of testing and replacing pipelines that have not been pressure tested or where documentation of such testing is not available "as soon as practicable" in response to Decision (D.)11-06-017. Phase 1A of our plan is designed to accomplish this for pipelines in populated areas over the next four years. In our judgment, this is an aggressive schedule to address the Commission mandate and a shorter time would not be practicable.

My testimony will briefly recap the regulatory history of how and why the question of pressure testing documentation arose in this proceeding. According to the well-established principles of the regulatory compact which governs the allocation of costs between utilities and their customers, I demonstrate why the outcome urged by DRA and Intervenors would result in a wholly unjustified penalty of unprecedented proportions compared to the cost recovery process SoCalGas and SDG&E have proposed. Furthermore, this enormous cost-shifting would effectively be a penalty but without any showing of unsafe or imprudent utility conduct; on the contrary, there are manifest examples of the safety-forward culture at SoCalGas and SDG&E stretching back for decades as discussed by SoCalGas and SDG&E witness, Mr. Lee Stewart. Where appropriate, I refer to the rebuttal testimony of other SoCalGas and SDG&E witnesses who cover some of these topics in greater detail as well as three expert witnesses who consider this issue from a broader regulatory and economic perspective.

The counterproductive Intervenor and DRA proposals to shift nearly all Pipeline Safety Enhancement Plan pipeline replacement and pressure testing costs to shareholders is unprecedented and unjustified and will most likely delay, if not derail, the clear intent of the

Commission to move expeditiously to a new level of pipeline safety. Although SoCalGas and SDG&E have an outstanding pipeline safety and reliability record, have made safety a top priority and have nurtured a safety culture that goes back several decades, SoCalGas and SDG&E are committed to make the investments expressed by the Commission in D.11-06-017 to further enhance the safety of our pipeline system. These safety enhancing investments can be made expeditiously only if shareholders are fully compensated for these investments with a reasonable, Commission-approved rate of return on invested capital. SoCalGas and SDG&E witness, Dr. David Montgomery, demonstrates that financing all future Pipeline Safety Enhancement Plan investments consistent with Commission-approved, reasonable rates is the most cost-effective approach for ratepayers in the long-term.

I. PROCEDURAL HISTORY

On June 9, 2011, in D.11-06-017, the Commission directed SDG&E and SoCalGas "to file a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)." The exclusion meant that California gas utilities would no longer be able to rely on records of operating history to establish maximum allowable operating pressure (MAOP) but must instead locate records of pressure testing in accordance with Subpart J[2] standards or conduct such pressure tests or replace the pipeline.

SoCalGas and SDG&E, as stated in Mr. Douglas Schneider's testimony, used the records identified through the records review process that was conducted in connection with the April 15, 2011 Report of Southern California Gas Company and San Diego Gas & Electric Company on

[2] 49 CFR 192 Subpart J.

Actions Taken in Response to NTSB Safety Recommendations as the basis for prioritizing the work in our Pipeline Safety Enhancement Plan. As stated in that report, SoCalGas and SDG&E undertook an intensive records search to identify gas transmission pipelines that did not have a documented safety margin of 1.25 times MAOP. Those pipelines that did not have this documented safety margin were placed in what we referred to as "Category 4," and it is Category 4 pipeline miles that form the basis of our Phase IA work in our Pipeline Safety Enhancement Plan.

Based on the Decision Tree set out at page 61 of Mr. Schneider's direct testimony (and page 4 of his rebuttal testimony), SoCalGas and SDG&E plan to pressure test or replace Category 4 pipelines (as well as some accelerated miles) during Phase 1A. It is these costs that Intervenors and DRA unjustifiably want to impose on shareholders based on the theory that SoCalGas and SDG&E are somehow imprudent because they lack sufficient documentation of a pressure test for these pipelines.[3]

II. SCOPE OF THE PROPOSED PENALTY

The Commission should be under no illusion about Intervenors and DRA's recommendation that shareholders bear these costs. Mr. Schneider's rebuttal testimony contains tables that show, by date of construction, the miles of pipeline for which SoCalGas and SDG&E concluded adequate documentation of pressure tests exists (Categories 1-2) and where it does not (Category 4).[4] Intervenors and DRA recommend some or all costs associated with testing or

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[3] Intervenors and DRA urging that shareholders bear these costs vary in their approach, their rationale, and as a result, in the total cost that would be shifted. Other witnesses for SoCalGas and SDG&E deal with these details. My testimony addresses the fundamental policies that are in conflict with *all* of these recommendations.

[4] SoCalGas and SDG&E also have in their April 15, 2011 Report a "Category 3." Category 3 included pipelines that had documentation sufficient to show that it had operated continuously at a pressure of at least 1.25 times greater than its current MAOP (i.e., an equivalent in-service gas pressure test). The Commission's June Decision

replacing Category 4 pipelines be shifted to shareholders. For Phase 1A, DRA recommends that the shareholders be responsible for $1,603 million or (96%) of the Pipeline Safety Enhancement Plan direct costs.   The smallest cost shift is TURN's, which would disallow "only" $274 million for replacement of aging infrastructure and limit the scope of the safety enhancement plan. To my knowledge TURN's proposed disallowance would still be the largest monetary penalty ever imposed by the Commission.

III. Breach of the Regulatory Compact

The regulatory compact that has traditionally governed the allocation of utility costs between ratepayers and shareholders is well known. In order to fulfill our statutory obligation to provide safe and reliable natural gas service to all of our customers, SoCalGas and SDG&E must operate our natural gas systems in accordance with applicable regulations and requirements, including the new post-San Bruno standards established by this Commission. The costs to comply with these new standards are therefore an unavoidable cost of providing natural gas service to our customers. In exchange for providing utility service pursuant to regulated rates, SoCalGas and SDG&E are entitled to recover these pipeline safety program costs, just as we are entitled to recover all other costs necessary to carry out our utility mission, as part of the regulatory compact.

Expert witness Dr. David Montgomery explains why the Commission needs to apply standard rate-making practices and rates of return on investments to the Pipeline Safety Enhancement Plan, and standard practices for penalties for violations of pipeline-related rules and requirements. By doing so, the Commission can simultaneously satisfy its goals of cost-

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(continued…)

does not allow for an in-service gas pressure test. Accordingly, for purposes of our PSEP filing, our Category 3 pipelines are included in a later Phase of our Plan.

effective service and safe and timely upgrades to the pipeline system. Dr. Montgomery also explains why the Commission should provide guidance on the appropriate balance between cost and quality of service during the general rate case process as part of the cost-of-service negotiations, and not after the fact, and why the disallowance proposals of DRA and other intervenors could have unintended and costly consequences for customers. SoCalGas and SDG&E operate on the expectation that regulators will ensure ratepayers pay rates that are "just and reasonable" while shareholders will be entitled to recover the reasonable costs of operating the enterprise, including the return of their invested capital and the opportunity to earn a reasonable rate of return on that investment. The opportunity (but not a guarantee) for the utility to earn a reasonable rate of return has been a long-standing principle of utility regulation. Operations and maintenance (O&M) costs and capital costs – however large they may be – are borne by ratepayers except to the extent they are proven to be unauthorized, unreasonable or imprudent. Intervenors point to certain regulatory or industry standards that, at various times and in varying detail, refer to document retention in general or pressure testing in particular. They then leap to the conclusion that any cost identified in our Pipeline Safety Enhancement Plan as the result of unavailable pressure test documentation must be the result of imprudent or unreasonable conduct. There are several reasons why this conclusion is contradicted by the facts and fundamentally at odds with the regulatory compact.

A. The Document Retention Standards

The "standard" first cited by the Intervenors is the one least applicable to the retention of pressure test records. DRA alleges that General Order (GO) 28 has required SoCalGas and SDG&E to indefinitely retain records associated with hydrostatic testing since its inception in 1912. This is incorrect. GO 28 has been understood and interpreted by utility personnel and by the Commission as applying only to accounting records. By its own terms, GO 28 speaks of "records, memoranda and paper supporting entries" in specified utility books of account. The only references to "equipment and plant" records are those "pertaining to depreciation and replacement." Records related to pressure testing are operational in nature and have never been considered accounting records. DRA attempts to shade the issue by stating that "records associated with the cost of hydrostatic testing" should have been retained indefinitely and would have been adequate documentation that such a test occurred. *See* DRA Report, Executive Summary and Cost Recovery Policy at 13. There is no reason to assume that a cost record of a test would provide the details necessary to document that the test complied with Subpart J.[5] To sweep in sufficient documents for that purpose would mean interpreting GO 28 to require SoCalGas and SDG&E to preserve forever all records related to any operational activity in the history of the company. To my knowledge, no Commission decision has ever interpreted GO 28 to impose this undue burden on utilities.

In the few Commission decisions in which GO 28 retention requirements have been discussed in detail, rather than imposing an indefinite retention requirement, the Commission simply redefined the utilities' obligation to retain documents as limited to reasonable periods of time of between one and seven years. In my experience, GO 28's accounting related record-keeping requirements have never been thought to require SoCalGas and SDG&E to retain records of hydrostatic testing for any period of time, and certainly would not require SoCalGas and SDG&E to retain these testing records indefinitely.

Pipeline industry expert witness Mr. Michael Rosenfeld explains in detail in his testimony the evolution of American Society of Mechanical Engineers (ASME) industry

[5] 49 CFR 192.

guidelines concerning post-construction pipeline pressure testing, records for such tests and the retention of such records. He demonstrates that for a long time, pressure tests were not required, test media and other conditions were not standardized, and the record retention standards did not exist or were not mandatory. Basing a disallowance on the lack of a record that might have been recommended but not required for a test that was also not required makes no sense. Even after the industry standard appears to make testing and recordkeeping a requirement in 1955, Mr. Rosenfeld points out many permissible exceptions. In addition, what constituted an appropriate "record" also changed over time. When the federal regulations came into effect in 1970, they included a provision that allowed operators to substitute for pressure test records the recent operating history of in-service pipelines in establishing the MAOP. This was an explicit recognition that many operators did not have pressure test records for their in-service pipelines. Based on Mr. Rosenfeld's explanation of the pressure test requirements, 95% of the SoCalGas (98% for SDG&E) pipelines in Category 4 were constructed before regulations required a post construction pressure test (See Rebuttal Witness Schneider – Table DMS-3). Imposing a retroactive requirement to pressure test pipelines constructed before 1961 without appropriate cost recovery may actually undermine the Commission's decision to enhance the safety of the aging transmission pipeline network, as economist Dr. Montgomery explains in his testimony.

In California, even though the Commission adopted (with some modifications) the ASME industry standard regarding pipeline testing and record retention in 1961 in the form of GO 112, it also embraced the grandfather provisions of the federal regulations when they were introduced, and the Commission did not require pipeline operators to go back and pressure test existing pipelines when GO 112 first went into effect. Since GO 112, by its literal terms, had required retention of pressure test records for pipelines constructed after its effective date, there should have been no reason for the Commission to allow operators to set MAOP based on operating records rather than pressure test records for any pipelines constructed after 1961. But in fact, GO 112 was amended in 1971 to allow the very same grandfathering options permitted by Part 192 for pipelines constructed before 1970. SoCalGas and SDG&E went through an extensive process to review their documentation regarding pipeline segments to achieve compliance with the new 1970 federal regulations.

Finally, as Mr. Douglas Schneider explains in greater detail, there are many instances where SoCalGas and SDG&E do have some documentation of pressure testing. While such records may well have met or exceeded whatever test or documentation requirements were then in effect, SoCalGas and SDG&E conservatively concluded they were insufficient to document the 1.25 times MAOP safety margin that SoCalGas and SDG&E used in response to the NTSB's January 3, 2011 recommendations to PG&E.

In all of these respects, the retention "requirements" cited by the opposition witnesses do not meet the requirements of clarity, certainty and consistency that are essential if huge monetary penalties are to be assessed for alleged non-compliance. Former pipeline regulatory official Mr. George Tenley elaborates on these requirements in his testimony.

B. Lack of a Showing of Unreasonable Conduct

Shareholder penalties are properly assessed when there is a showing that the conduct is the result of a serious failure of utility management amounting to deliberate disregard of clear regulatory direction or performance consistently and demonstrably below industry norms. Gaps in documentation for activities that took place up to 90 years ago do not justify cost shifting from ratepayers to shareholders, as Mr. Tenley explains in his testimony. That has also been my experience in terms of penalties imposed by the Commission. As Mr. Stewart and Mr. Rosenfeld explain, there can be numerous and entirely innocent explanations for why records of activities that occurred 50 to 90 years ago may not have been created or no longer be available. Furthermore, as the tables in Mr. Schneider's rebuttal testimony indicate, both SoCalGas and SDG&E did locate adequate documentation of pressure testing for many lines built even before 1955. Hence, there is no basis to conclude there was a consistent pattern of disregard of record retention. The burden is on those recommending a penalty to provide evidence that the costs incurred were due to serious utility misconduct in the face of clear requirements and notice as to the importance of strict compliance. That showing has not been attempted, much less demonstrated in this case. Indeed, in connection with some of its other recommendations, DRA points out the good safety record of SoCalGas and SDG&E.

C. Evidence of Utility Safety Consciousness

Record retention is only one component of a safety program. As Mr. Tenley explains in his testimony, to assess an operator's attitude toward safety, it is essential for the regulator to look more broadly at all of the pipeline operator's business practices, operation history, risk assessment and management, and emergency preparedness and response. The opposition witnesses assume that lack of records proves a seriously deficient attitude toward operational safety on the part of SoCalGas and SDG&E over the years and therefore justifies enormous shareholder penalties. Nothing could be further from the truth. Witnesses Schneider and Stewart offer many examples of safety conscious actions stretching back for decades. Witness Tenley offers a similar view of SoCalGas as a leading operator from a regulator's perspective. Imposing unprecedented penalties on shareholders of utilities with this demonstrated commitment to safety would turn the regulatory compact upside down. It would also create counterproductive incentives for the utilities with possible unintended, adverse consequences, as Dr. Montgomery explains.

IV. COST RECOVERY FOR RESOLVING RECORDS ON PIPELINES INSTALLED POST-1970

As a result of the initial review of pipelines that culminated in the April 15, 2011 report and the development of the August 26, 2011 Pipeline Safety Enhancement Plan filing, SoCalGas and SDG&E identified some pipelines that were constructed after 1970 that did not have complete documentation of a post construction pressure test. At the end of 2011 there were about 7 miles of pipelines (6 miles at SoCalGas and 1 mile at SDG&E)[6] that did not have complete pressure test records. Based on information from inspections, maintenance and operational records, and company construction standards we are confident these segments were installed in compliance with applicable code requirements. However, given the testing and recordkeeping regulations in effect when these segments were built, steps are being taken to either retest or replace these segments. SoCalGas and SDG&E are not seeking cost recovery through our Pipeline Safety Enhancement Plan for this work.

V. Mitigating Customer Impacts

Replacing or hydrotesting a line can cause a customer's service to be interrupted in order to perform the work. SoCalGas and SDG&E intend to continue our past practices of considering these interruptions when planning work such that service to core customers is not interrupted. In addition we are committed to minimize the impact on noncore customers. In that regard we will work with noncore customers to determine the possibility and duration of an outage and will

[6] As of year-end 2011, as part of the review of NTSB criteria miles, SoCalGas identified 5.82 miles (53 pipeline segments) and SDG&E identified 0.95 miles (14 pipeline segments) that were constructed after 1970 and lacked documentation of the pressure test.

manage any interruptions in accordance with the applicable tariffs. Should interruptions be necessary we will work with noncore customers to plan, where feasible, service interruptions during scheduled maintenance, down time or off peak seasons.

The evaluation process will start with a determination of whether or not taking a pipeline out of service for pressure testing would result in the loss of gas service to a customer. If service would be interrupted, alternatives to maintaining service to customers during pipeline outages will be evaluated. While SoCalGas and SDG&E will not interrupt service to core customers in order to pressure test a pipeline, we will determine whether there is a viable alternative method of providing gas service to impacted customers (i.e. CNG service, LNG service, installation of temporary bypasses, etc.).

VI. Control of Pipeline Safety Enhancement Plan Costs

The fact that SoCalGas and SDG&E propose that Pipeline Safety Enhancement Plan costs are to be recovered from ratepayers – including those costs due to the absence of pressure test records – does not mean that SoCalGas and SDG&E are ignoring their cost control responsibilities under the regulatory compact. It is true that the Pipeline Safety Enhancement Plan cost estimates for this unprecedented and tightly scheduled work are not as detailed and complete as might be possible if Phase 1A of our Pipeline Safety Enhancement Plan were scheduled over the next decade rather than the next four years; but the estimates were developed based on a thoughtful, rational process that relied upon considerable expertise and experience, and these estimates provide a reasonable cost projection for the Commission to approve our plan.

Mr. Rick Phillips' testimony recommends that an Advisory Board (with representation from CPSD, the Energy Division, and a mutually agreed upon outside expert) be created to provide visibility and input to the utilities as the work proceeds. This advisory board will provide the Commission staff with transparency to the decision process. Moreover, witness Mr. Ed Reyes (adopting Ms. Cheryl Shepherd's testimony) demonstrates the several points at which Commission staff and interested parties will be advised of incremental cost projections and have opportunities to review and object to those costs. For all of these reasons, as well as the general disadvantages discussed by Dr. Montgomery, an after-the-fact reasonableness review of Pipeline Safety Enhancement Plan costs should be avoided.

VII. Conclusion

The enormous cost shifting proposals of witnesses from DRA, TURN, SCGC and SCIP/Watson are unjustified by the conduct of the utilities, unsupported by the evolution of standards or regulations, and directly contrary to the principles of the regulatory compact as applied by this Commission and should therefore be rejected.

CHAPTER 2

COST RECOVERY POLICY

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PREPARED REBUTTAL TESTIMONY

OF W. DAVID MONTGOMERY

I. INTRODUCTION

My name is W. David Montgomery, and I am Senior Vice President of NERA Economic Consulting, 1255 23rd Street NW, Washington, DC 20035. My relevant experience includes teaching, government service, research and consulting dealing with natural gas and regulation of energy markets. I have a Ph.D. in economics from Harvard University and taught economics at Caltech and Stanford. My publications include papers on utility regulation and on natural gas markets and regulation in the *American Economic Review* and in other peer-reviewed journals and edited volumes. I have testified before the U.S. Congress on numerous occasions on topics dealing with energy regulation and energy and environmental policies. I appeared before this Commission in its investigation of natural gas price increases in California in 2000 and 2001 and have been an expert witness in antitrust litigation, international arbitration, and price manipulation investigations involving natural gas markets. My qualifications are addressed in more detail in my resume which is attached in the Qualifications chapter of this testimony.

The purpose of this testimony is to address the economic consequences of proposals by certain Intervenors to require shareholders of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) to assume financial responsibility for a substantial portion of the costs associated with the utilities' proposed Pipeline Safety Enhancement Plan (PSEP). For the reasons I will explain, these Intervenor proposals are not only unfair, but also short-sighted, inconsistent with precedent from other regulatory jurisdictions, and unsound from an economic standpoint.

II. GOAL OF THE COMMISSION

Following the San Bruno explosion, the California Public Utilities Commission (Commission) released an unprecedented safety directive (D.11-06-017) requiring natural gas utilities in California to test or replace all pipeline segments in their system, and to maintain all test records going forward. A report issued by the NTSB in the aftermath of the explosion stated that Pacific Gas and Electric Company (PG&E) had inadequate knowledge of the pipeline segment in question, and that PG&E's substandard pressure testing and recordkeeping practices may have contributed to the event. The Commission cited these issues as justification for the new rule:

> This decision orders all California natural gas transmission operators to develop and file for Commission consideration A Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plans) to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipelines that have not been pressure tested.[1]

The stated goal of the Commission, then, is not just to improve the safety of the natural gas transmission and distribution systems in the state of California but also to do so without incurring unnecessary cost.

III. THE REGULATOR'S CHALLENGING TASK

The Commission faces several challenges in meeting this goal. In its role as the regulator, it must define the acceptable level of safety to the utility companies, provide oversight and incentives to ensure that that level of safety is achieved, and impose penalties if it is not. Furthermore, there is a tradeoff between the safety, reliability, and robustness of a system (often collectively referred to as "quality of service"), on the one hand, and on the other hand, its cost: each incremental improvement to the quality of service of the system entails additional materials

[1] D.11-06-017, mimeo., at 1.

and redundancies that increase its cost. Rather than prescribe in detail the specifics of the system design and operation, the regulator delegates that responsibility to the utility company, which has far greater knowledge of its system and the options for improving safety than the Commission.

This asymmetry of information makes it necessary for the Commission to use incentives rather than command and control oversight to strike a balance between the quality of service provided by the utility, and the cost which the customers must pay for that service. The regulated utility has a financial incentive to expand service quality if it can recover the costs of service, and an incentive to avoid customer complaints to the regulator.[2] To balance these incentives, the regulator typically provides minimum acceptable standards for service with sanctions for violating those standards.

Necessarily, when the standard for service quality is changed, the incentives for delivering that service must also be considered. When proposing new testing requirements and replacement of large parts of the system to achieve a higher level of service, the regulator must realize that if it does not allow the full costs to be recovered by the utility from ratepayers, the utility will endeavor within the law and rules of the Commission to minimize the impact of those costs on its shareholders.

The Commission itself has stated that its objective is to improve safety in a cost-effective manner. To achieve this, the incentives created by the Commission's actions must cause the utility to choose actions that fall within the bounds of desired behavior defined by the regulator. For the utility, there must be a financial incentive to design and implement the safety improvements wanted by the Commission in a manner that avoids excessive cost: expected returns from carrying out the safety improvement program in a cost-effective manner should be

[2] *See* discussion of "Limited Attention to Quality of Service" in Kahn, A.E., 1970, *"The Economics of Regulation: Principles and Institutions*, John-Wiley and Sons, New York: Volume 1: Economic Principles, Chapter 2.

greater than the expected returns from any other course of action. A well-designed system of constraints and incentives will achieve the standards of service at least cost to the consumer. In contrast, a poorly designed regulatory system, as discussed below, will create perverse incentives that neither achieves the goals of service quality nor delivers low cost to customers.

Failure to provide for full cost recovery can bias utility decisions in three ways:

- By encouraging utilities to design and implement improvements to avoid unrecoverable expenditures rather than to minimize the total cost of the changes;
- By creating an incentive for utilities to overspend on future safety-related activities to avoid disproportionate penalties; and,
- By changing the risk assessments of future investors in a manner that will depress share prices and raise the cost of financing future investments of all types.

It is not necessary to develop a full theory of how to design optimal incentives to identify a clear way to maintain proper incentives in this case: it is for the Commission to apply its standard principles of ratemaking that have been determined to work well for all the rest of its regulation of gas utilities. That is, the objectives of the Commission for the safety improvement program will be best achieved by allowing for full cost recovery after review of the plans proposed by the utility, rather than using disallowances or lowered returns on future expenditures. If there is evidence of past violations of rules or policy that meet the Commission's criteria for lump-sum penalties, those can be separately considered and imposed.

IV. THE INTERVENORS' PROPOSALS

The Intervenors argue that:

- SoCalGas and SDG&E shareholders should be entirely responsible for all of the expenses associated with testing and replacing pipelines installed after 1955 for which a reliable record of a pressure test cannot be found.[3]
- SoCalGas and SDG&E shareholders should be entirely responsible for all expenses associated with testing pipelines installed between 1935 and 1955 for which a reliable record of a pressure test cannot be found.[4]
- If the Commission authorizes replacement rather than testing for pipelines installed between 1935 and 1955 for which a reliable record of a pressure test cannot be found, the return on equity for those capital investments should be adjusted downwards by 200 basis points.[5]

The economic implications of adopting these proposals are discussed below.

V. THE RISK OF EXCESSIVE PENALTIES

The Commission already has a penalty structure in place which provides the scope to assess a dollar penalty for violations of rules or procedure and/or allows for civil suits and liability against the utility.[6] These mechanisms, when used appropriately, are advantageous from an economic standpoint. They simultaneously provide a penalty for past improper behavior and an incentive for future good behavior, in the form of avoided future penalties or lawsuits.

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[3] Division of Ratepayer Advocates (DRA) Testimony (Peck) at pp. 10-16; *see also* The Utility Reform Network (TURN) Testimony (Long) at pp. 14-18 (recovery of testing and replacement costs should be denied for pipeline segments constructed after 1955); Southern California Generation Coalition (SCGC) Testimony (Yap) at 12-14 (recovery of testing and replacement costs should be denied for pipeline segments constructed after July 1, 1961); Southern California Indicated Producers/Watson Cogeneration Company (SCIP/Watson) Testimony (Beach) at p. 4 (same position as SCGC).
[4] DRA Testimony (Peck) at pp. 15-16.
[5] DRA Testimony (Peck) at pp. 16-18.
[6] *See* Public Utilities Code Sections 2106 and 2107.

Penalizing unacceptable behavior is an important part of the regulator's responsibility, and is critical to giving the utility incentives to deliver acceptable service. There is a large volume of literature on the appropriate design of economic penalties.[7]

The economic literature teaches us that the most important issue in designing a penalty structure for violations of regulatory policy and rules is a consideration of the incentives that they invoke. A penalty that alters future incentives rather than taking the form of a lump-sum payment may have unintended consequences that work against the original purpose of the regulator. In particular, the literature emphasizes that excessive penalties can lead to what used to be called "scrupulosity:" expenditure of large amounts of resources to avoid every minor infraction in a particular category whose importance to the regulator is far less than the social cost of resources devoted to over-compliance. This is particularly the case when the regulated entity does not know with certainty, before the fact, what will constitute a violation.

A penalty in the form of disallowance of future costs is an example of a misguided penalty. If the Commission determines that a violation has occurred, it should assess the penalty according to its established criteria, in proportion to the infraction, and to align with future incentives for good behavior. The Environmental Protection Agency (EPA) argues that the penalty "*should persuade the violator to take precautions against falling into noncompliance (specific deterrence) and dissuade others from violating the law (general deterrence).*"[8] Accordingly, the agency policy is, "*to remove any significant economic benefits resulting from failure to comply with the law*," for example by assessing a penalty at least as great as the

[7] For example, Gary Becker's classic, "Crime and Punishment: An Economic Approach," Journal of Political Economy 76 (1968) at pp. 169-217, and a more recent survey in Mark A. Cohen "The Economics Of Crime And Punishment: Implications For Sentencing Of Economic Crimes And New Technology Offenses" 9 Geo. Mason L. Rev. 503 Winter, 2000.
[8] *See* EPA Policy on Civil Penalties and related documentation, http://cfpub.epa.gov/compliance/resources/policies/civil/penalty/

violator gained, plus interest. This minimum penalty is supplemented with a penalty assessed in proportion to the gravity of the violation. Appropriate penalty guidelines provide for fair and equitable treatment of the regulated community, meaning consistency, flexibility, and consideration of the specifics of the case and the history of the offender in calculating the penalty.

In this case, the penalty suggested by the Intervenors does not meet either of the criteria for economic efficiency. On the first count, the penalty is grossly disproportionate to the purported infraction. The inability to locate all possible historical testing records seems to be a clerical error rather than a fundamental misdeed, especially in light the pipeline segments at issue and the safe operations of SoCalGas and SDG&E as a whole (which should take primacy over a test record when evaluating system safety), the technological changes over the past 80 years (which make accessing historical information both difficult and costly), and the absence for many years of specific directives on recordkeeping by the regulator. Furthermore, it would be difficult to tally any gains that SoCalGas and SDG&E could have achieved by failing to keep records.

Second, the penalty suggested by the Intervenors is imposed in a manner that creates perverse incentives for future safety investments. By denying future cost recovery of the utility, the suggested penalty creates a disincentive for making precisely the investments in pipeline maintenance and safety that the regulator is trying to encourage.

VI. INCENTIVE DISTORTIONS AND INCREASED COSTS

An investor-owned utility company has a duty to achieve or exceed Commission-approved shareholder returns subject to rules of the Commission. Because the rates that it can charge are fixed between general rate case reviews, a regulated utility enhances shareholder returns by minimizing costs of production while meeting defined service obligations. A well-known theory of the effects of regulation advanced by Averch, Johnson and Wellisz[9] observed that under rate-of-return regulation with instantaneous rate adjustment, a utility would have an incentive to choose overly capital-intensive projects if its allowed rate of return exceeded its cost of capital and to avoid capital expenditures if its allowed rate of return were below its cost of capital. It has also been observed that both regulatory lag and performance-based regulation served to restore the incentive for the utility to minimize cost.[10]

An action that disallows some percentage of the cost of future investments in safety or that reduces the rate of return on those investments will have precisely the consequences of the "reverse AJW effect" in that it will give the utility an incentive both to minimize capital expenditures in designing its safety improvement program (to reduce exposure to the rate of return penalty) and to delay and avoid as much as possible making these expenditures.

A retroactive penalty on past infractions may also have unintended consequences. In this case, the Intervenors propose penalties because of unavailable records of past tests. It is my understanding that the Commission did not heretofore penalize or cite utilities for the failure to keep such records. By imposing a new standard and imposing large penalties for imperfect compliance, years after an activity takes place, the regulator creates uncertainty about what standards will be applied in the future across the board.

As in other cases of retroactive application of new standards, the combination of onerous retroactive penalties with uncertainty about how much more stringent standards might be made

[9] Averch, Harvey; Johnson, Leland L. (1962), "Behavior of the Firm Under Regulatory Constraint." American Economic Review 52 (5): 1052–1069.

[10] Paul L. Joskow, *Incentive Regulation In Theory And Practice: Electricity Distribution And Transmission Networks*. Prepared for the National Bureau of Economic Research Conference on Economic Regulation, September 9-10, 2005.

in the future can lead to excessive avoidance behavior.[11] After experiencing such change in requirement and penalty, the utility would have an incentive to greatly overdo safety-related expenditures and recordkeeping for all future maintenance and construction to avoid any chance of such treatment in the future.

Unless the Commission is willing to greatly increase its budget for inspections and oversight, the utility will always have more information and insight into how to maintain and improve safety in a cost-effective manner than Commission staff or Intervenors. These changes to utility incentives will send conflicting signals to the utility and as a result will decrease efficiency and raise costs. By disallowing costs and providing unfavorable rates of return in selected operational areas, the regulator would encourage minimum capital investment in these areas (so as to minimize the capital on which they collect the subpar returns). These decisions tend to be more costly in the long term. For an illustrative example, consider the switch from innovative generation technologies to more costly conventional ones following the hindsight reviews of the 1970s.[12]

VII. POTENTIAL IMPACT OF INTERVENOR PROPOSALS

The Intervenors' proposals would create two different but equally undesirable incentives for SoCalGas and SDG&E. For the pre-1970s pipelines that are at issue in this proceeding, the Intervenors propose cost disallowance and a reduced rate of return in performing upgrades. As discussed above, this creates an incentive to minimize capital expenditures beyond the point that would lead to the most cost-effective outcome – in particular to replace as few of these pipe

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[11] If the Commission's retroactive application of penalties is seen as breaking precedent, it can create the perception that the Commission will act unpredictably in the future. Facing unpredictable future penalties, the mode of decision-making in a utility can shift from balancing expected costs and expected benefits to variations on minimizing the maximum possible loss. This could entail attempting to eliminate any possibility of a penalty by adopting internally standards and costs far greater than the Commission intends at present.

[12] *See, e.g.*, discussion in Lyon, T.P. (1995) "Regulatory Hindsight Review and Innovation by Electric Utilities," *Journal of Regulatory Economics*, 7:233-254.

segments as possible and keep them in the system for as long as possible using high levels of future O&M. Under the Intervenors' proposals, the pre-1970 pipeline system, then, is likely to be upgraded in a way that makes it more expensive to operate going forward.

For all other pipeline-related expenditures, the impact of the Intervenors' proposals is markedly different. The disproportionate penalty proposed by the Intervenors for missing paperwork creates an incentive to maintain and operate the entire system going forward so as to avoid any chance of being judged guilty of a future violation. This would involve redundancy in pipeline construction, testing, maintenance and recordkeeping in excess of a reasonable standard of economic efficiency. By holding the utility retroactively to a new and higher standard, the Intervenors' proposals create an incentive for a more costly system that would be proof against unknown future changes in standards.

In sum, the Intervenors' proposals would raise costs to the ratepayer by providing explicit incentives to (1) minimize and delay capital investment in bringing the pre-1970 segments up to new standards, and (2) to maintain the entire system going forward in a redundant and costly manner.

VIII. PRECEDENTS

Issues of safety and reliability are commonly encountered in the electric and natural gas industries. Given the tension between service quality and cost, the vicissitudes of energy demand, and the influence of natural forces, it is unsurprising that systems sometimes break down, and that determining how best to maintain and upgrade them is not always clear. Yet rulings from other jurisdictions and previous rulings by the Commission have acknowledged that in a cost-of-service system the best results are achieved if the future incentives of the utility are aligned with customer priorities by providing for full recovery of all reasonable costs. For example, the Maryland Public Utility Commission recently completed a review of the reliability of electric service by Potomac Electric Power Company (PEPCO).[13] The Commission balanced the need for punishment due to past inadequacy of service quality with the need for prudent forward-looking incentives for service improvement. After finding clearly supported evidence of inadequate investment and poor management in the past, but with an eye towards aligning the incentives of the utility, they assessed a lump-sum penalty and imposed reporting requirements, but did not fundamentally alter the cost-recovery mechanisms of the utility.

In 2005, the Michigan Public Service Commission, "*concerned that* (the gas utility Michigan Consolidated*) have the financial ability to meet these new safety and training-related costs*," allowed cost recovery for additional unplanned expenses associated with pipeline safety in meeting the Federal Pipeline Safety Improvement Act (FPSIA) of 2002, while also improving oversight by using additional reporting requirements.[14] Similarly, the Indiana Utility Regulatory Commission, recognizing that the utility (Indiana Gas Company) "*is now incurring and will continue to incur incremental compliance expenses*" due to the new safety standards imposed by FPSIA, authorized an expansion of the utility rate cap and provision for future recovery of deferred costs.[15] Both of these rulings, along with precedent on cost recovery of integrity management expenses from FERC, were noted in the Independent Review Panel Report on the San Bruno pipeline explosion.[16]

In addition, many judicial rulings have endorsed the principle that utilities be allowed sufficient revenue to cover costs and earn a risk-adjusted rate of return. The U.S. Supreme Court

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[13] Order No. 84564, Case No. 9240, In the Matter of an Investigation in the Reliability and Quality of Electric Distribution Service of Potomac Electric Power Company, Maryland Public Service Commission, 12/21/2011.
[14] *Michigan Consolidated Gas Co.*, Opinion and Order Granting Rate Relief, Case No. U-13898 at 74-76 (Apr. 28, 2005).
[15] Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43967.
[16] June 9, 2011: Independent Review Panel Report on San Bruno Pipeline Explosion, Appendix Q: "Public Policies in the State of California: Ratemaking Regulatory Regime" http://www.cpuc.ca.gov/PUC/events/110609_sbpanel.htm

in the *Bluefield* case notes (in affirming that rates must be sufficient to yield a reasonable return): "This is so well settled by numerous decisions of this Court that citation of the cases is scarcely necessary."[17] The California Public Utilities Commission determines reasonable operating costs that utilities incur "*to maintain their systems in accordance with the Commission's safety and reliability standards and industry best practices.*"[18] It follows that when the Commission's safety and reliability standards tighten, additional cost recovery should be approved. Recent rulings by the Commission have validated the idea that financial incentives encourage future utility priorities (in the context of energy efficiency rather than pipeline safety):

> We are of the opinion that subjecting the IOUs to penalties or substantially reduced incentives based on factors they could not reasonably be expected to anticipate or effectively respond to will do little to motivate them to aggressively pursue energy efficiency, and may undermine the interests of the people of the state of California in placing energy efficiency on a par with "steel-in-the-ground" supply-side resources. By adopting this approach, we ensure the mechanism remains effective in aligning utility and ratepayer interests with respect to the resource priorities of the state.[19]

The Commission echoed Congress in recognizing the need to provide financial incentives in order to encourage utility priorities: "*Rates charged . . . shall be such that the utility is encouraged to make investments in, and expenditures for, all cost-effective improvements in the energy efficiency of power generation, transmission and distribution.*"[20]

IX. REGULATORY OPPORTUNISM

Because utility investments in infrastructure are costly and irreversible, an assurance of future cost recovery is necessary prior to undertaking investment. Stable policies regarding cost

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[17] *Bluefield Water Works & Improvement Company v. Public Service Commission*, 262 U.S. 679 (1923); and previous precedent in *Smyth v. Ames*, (1898) 169 U. S. 467, 169 U. S. 547, *Willcox v. Consolidated Gas Co.*, (1909) 212 U. S. 19, 212 U. S. 41, 212 U. S. 52, *Minnesota Rate Cases*, (1913) 230 U. S. 352, 230 U. S. 434, and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[18] California Public Utilities Commission, Electric & Gas Utility Cost Report; Public Utilities Code Section 747 Report to the Governor and Legislature at 30 (Apr. 2011).

[19] D.10-12-049, mimeo., at 7.

[20] Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776, Oct. 24, 1992.

recovery and standards of service are critical to maintaining shareholders' assessments of the risks of investing in the utilities in question. Although many jurisdictions are evolving from traditional cost of service regulation to performance-based regulation,[21] both forms of regulation include several key components:

- No retrospective ratemaking – costs that were determined to be prudent at the time incurred are not to be disallowed with benefit of hindsight. Expenditures to meet new requirements are not disallowed because they could have been made earlier.
- The reasonableness of capital investment plans to assure adequacy and cost-minimization is reviewed and approved in advance of commitment and not revisited later.[22]
- Costs of meeting new regulatory requirements (environmental regulations, renewable energy standards, social expenditures, tax increases) are borne by ratepayers not shareholders.
- Automatic pass-through of costs that are known to change unpredictably (fuel cost adjustment), possibly with incentive mechanisms to motivate risk management and hedging.
- Any penalties or damages borne by shareholders take the form of a fixed payment not a reduced rate of return or disallowance of a category of future costs.

[21] Traditional cost of service regulation allocates cost risk to ratepayers rather than shareholders and makes it possible for utilities to have a lower cost of capital and therefore lower rates; performance-based variations share some risks between shareholders and ratepayers <u>in a pre-defined manner</u> to provide <u>forward-looking</u> incentives for improved performance.

[22] SoCalGas and SDG&E have proposed a variation on advance review, because extensive testing and evaluation are needed to determine how best to improve the system to meet the new standards. Since the cost of safety upgrades cannot be calculated before those decisions are made, SoCalGas and SDG&E are requesting advance review of the criteria to be used in making decisions about testing or replacement, with later review of costs limited to checking that the criteria were followed. As explained by the SoCalGas and SDG&E witnesses sponsoring this proposal, it would enable the utilities to use better information as it is developed as the basis for their decisions on whether to test, repair, or replace rather than adhering to a set of decisions made in advance without that information, and it would also free the utilities from retroactive review of whether their decisions were correct.

Ratepayers benefit from application of these principles because they reduce some of the risks of long-term investment by eliminating the possibility of unexpected alterations of the rules of cost-recovery, while at the same time they motivate utility management to make cost-effective decisions about the design of investments and the operation of the system.

Regulatory opportunism is a term used to describe a situation in which the regulator leaves open the possibility that it will not allow utilities to recover the cost of sunk capital.[23] As Guthrie (2006) notes: "*the lack of regulatory credibility induces myopic behavior by the firm: a strong incentive to delay cost-reducing investment, or, if the firm does invest, it will favor a series of sequential investments over a single larger, cheaper investment…The prospect of regulatory opportunism means that the firm will not fully exploit economies of scale in investment…,*" which lowers consumer welfare.

Many of the proposals put forth by the Intervenors encourage regulatory opportunism. In particular, the proposals for cost disallowance and retrospective review of past expenditures will reduce the credibility of the regulator with the utility and the investment community, and will result in the suboptimal (and costly) behavior described above.

X. COST RECOVERY AND REASONABLENESS REVIEWS

Traditionally, the details over the quality of service delivered and recovered costs get resolved in the utility's general rate case. As DRA points out, the Commission "must rigorously review cost recovery requests"[24] associated with pipeline safety. The suggestion that such a review be conducted ex-post, however, creates a perception of regulatory opportunism and is economically inefficient.

[23] *See, e.g.*, Guthrie, G., (2006) "Regulating Infrastructure: The Impact on Risk and Investment," *Journal of Economic Literature*, V. 44, December, pp. 925-972.
[24] R.11-02-019, Reply Brief of DRA dated May 31, 2012, at p. 15.

Ex-post reviews, sometimes called reasonableness or prudency reviews, are a mechanism designed to assess whether past expenditures were made appropriately. Under certain circumstances, the Commission conducts such reviews. However, the temptation to critique past decisions with 20-20 hindsight tends to create a skewed view of what constitutes "reasonable" or "appropriate." In much the same way that punishing a stock trader for incorrectly predicting the peak price of a stock does not produce a better trading strategy, using ex-post reviews to judge reasonableness sets an unfair burden of foresight on the utility.

Similar to disallowance of future costs, 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. Utilities will also be less willing to take risks on new technologies, even if they offer possibilities of achieving other social objectives for technology improvement and lowered environmental impact. The old phrase that "nobody ever lost his job for choosing IBM" characterizes this behavior.

If there were just one simple, low-cost way to design systems for the safe and reliable operation of a complicated natural gas transmission and distribution system, perhaps such a regime would be harmless. In reality, the types of investment incentivized by ex-post reviews tend to be more expensive to operate, less innovative, and therefore more costly to ratepayers in the long run. The experience of electric utilities in the 1970s, again, provides empirical support for this point. After having much of their sunk investment disallowed, and facing ex-post reasonableness reviews going forward, many utilities became extremely risk averse and inefficient in their investments, raising the cost to ratepayers without providing an improvement in service.[25]

XI. EFFECTS ON RATES AND RATEPAYERS

The Commission's goal in this ruling is to improve safety through a cost-effective program of pipeline testing and replacement. To achieve this goal, the Commission must align the incentives of the utilities to achieve the new safety standard while defining the appropriate level of cost-recovery for the additional expenditures that the utilities must undertake. The Intervenors' proposals would work against the Commission's goal in two ways: First, the retroactive regulatory change and cost disallowance would distort incentives and result in potential unintended consequences for safety improvement, as discussed. The second effect would be an unambiguous cost increase for ratepayers.

The Intervenors' proposals amount to an arbitrary and disproportionate penalty, which adversely affects the willingness of shareholders to invest in future infrastructure programs, ultimately increasing the cost of financing for new investment.

This appearance of a new risk of regulatory opportunism would not be limited just to the safety investment program. Unless the Commission could reverse the altered perception, a longer-term cost of the Intervenors' proposals would be the added cost of all new investment by the utilities. The Intervenors' proposals would be a qualitative change in the regulatory regime, with potentially severe implications for future utility investment decisions in all areas. This change in incentives, and the foreseeable change in behavior, seems to have been fundamentally misunderstood by the Intervenors, as seen in their analysis of utility investors:

> Investors understand certainty, and they understand incentives. If the Commission takes decisive action that results in safety investments, even at the cost of PG&E shareholders, the investment community will

[25] *See* discussion in Lyon (1995) or Guthrie (2006) on this point.

> understand and *respect* that California is holding PG&E accountable for its prior acts.[26]

Intervenors confuse the assessment of penalties to discourage violations of rules and policies with forcing shareholders to bear part of the cost of prudently incurred future investments. If a regulator imposes penalties that are proportional to the offence, that create incentives for desirable behavior, and that are consistent with the expectation of shareholders about regulatory behavior, the share price and cost of capital should not be affected by such penalties. This neutrality will disappear if regulators penalize past actions in ways that create an expectation among shareholders that future investments are subject to the risk of having partial cost recovery or a lower return imposed on them.

The economic link between risk and rate of return is well established. Simply put, it is necessary to offer higher returns to compensate investors for an investment with additional risk. The Intervenors deny this obvious link when they state that investors will 'respect' the Commission more if it punishes them by restricting their future rate of return.[27] The more sensible economic outcome is that investors will see higher risks associated with new capital investment projects in California, because the Intervenors' proposals would assure them a lower rate of return. As a result, the borrowing costs for the utilities, and the rates borne by ratepayers, will rise.

The direct effect of the Intervenors' flawed proposals on capital markets is straightforward: the reduction in the allowed rate of return will lead to higher borrowing costs. The greater concern posed by the Intervenors' plan, however, is the longer-term, potentially

[26] R.11-02-019, Reply Brief of DRA dated May 31, 2012, at p. 13 (emphasis in original).
[27] Although it is difficult to quantify 'respect' in the context of the capital markets, the Intervenors seem to argue that investors will react positively to a proposal that costs shareholders. Another, more plausible outcome is that investors will place a downward assessment on the future returns of holding utility company equity, which will make it more costly for the company to raise capital.

irreversible rise in the cost of all new investment, and a commensurate rise in the cost to ratepayers. Regulatory opportunism would put the California utilities in a different, higher risk class: If the utilities cannot be assured of cost recovery for long-term investments in infrastructure, they will be reluctant to make them, and investors will be reluctant to pay for them. The Intervenors' proposals thus designate safety improvements as higher risk, from an investment standpoint, which is exactly the opposite of the Commission's stated goal. Again, the Intervenors' fundamental misunderstanding of the economics of investment is clear from their own language:

> There is no reason to believe that continuing the California utilities' high returns on equity will result in safer systems. In fact, there seems to be no correlation between returns on equity and safety, unless it is an inverse one.[28]

DRA completely misses the point that it is the design of incentives that matters for both safety and cost. Although the Intervenors purport to value cost-effective service, their proposals seem designed to raise the costs to ratepayers by introducing inefficiencies into the process for improving system safety.

XII. CONCLUSION

Overall, the economic consequences of adopting the Intervenors' proposals would be higher rates due to: (i) increased expenditures to avoid excessive penalties; (ii) incentives to choose less than optimal capital expenditures for pre-1970 pipeline replacements and upgrades; (iii) incentives to build in redundant levels of safety in future capital projects and O&M expenditures; and (iv) increased cost of capital due to a lower rate of return on the utilities' capital investments.

[28] R.11-02-019, Reply Brief of DRA dated May 31, 2012, at p. 13.

In contrast, by simply applying its standard practices for penalties and its standard rate-making practices and rates of return on investments, the Commission can simultaneously satisfy its goals of cost-effective service and safe and timely upgrades to the pipeline system. If careful consideration reveals that a penalty is warranted related to recordkeeping, it should be assessed according to the Commission's well-established criteria, rather than by using a skewed notion of appropriate behavior informed by hindsight. Guidance on the appropriate balance between cost and quality of service should be introduced during the general rate case process as part of the cost-of-service negotiations, not ex-post. Actions which restrict the future rate of return on investments alter the incentives of the utility and have unintended and costly consequences for the ratepayer. Careful design of incentives does not alleviate the burden of oversight by the regulator; however, following capricious and misguided proposals for punitive action has long-term negative implications for the cost of service to utility customers.

CHAPTER 3

REGULATOR PERSPECTIVE ON

PIPELINE SAFETY

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PREPARED REBUTTAL TESTIMONY

OF GEORGE W. TENLEY, JR.

I. INTRODUCTION

My name is George W. Tenley, Jr., and I am a former regulatory attorney and administrator for the United States Department of Transportation ("the Department") where I served in various capacities for more than twenty years, including as Associate Administrator for Pipeline Safety in the Department's Research & Special Programs Administration (RSPA) (the precursor to the Pipeline and Hazardous Materials Safety Administration [PHMSA]). This rebuttal testimony is presented on behalf of the Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) regarding pipeline safety as it relates to their Pipeline Safety Enhancement Plan (PSEP). Although my testimony discusses, as relevant, my specific knowledge of and experience with SoCalGas, I understand that the quality, capabilities, and ethics of SoCalGas' pipeline management system have been governing SDG&E's pipeline system as well since at least 1998.

A. Qualifications

By training and experience, I have been a federal regulator and strategic advisor on pipeline safety regulations, enforcement, and compliance; pipeline risk management planning; and other broad aspects of pipeline operations. From 1969-1986, I served as a regulatory attorney for the Department's Federal Aviation Administration and RSPA. In 1986, I became Chief Counsel of RSPA where I was responsible for all legal matters associated with RSPA's hazardous materials and pipeline safety programs. In that capacity, I served as head of the Office of Pipeline Safety (OPS) which oversees all pipeline matters within RSPA (and now PHMSA).

The Department's pipeline safety program has oversight responsibility for a transportation system of 2.1 million miles of pipe transporting natural gas to more than 70 million residential and commercial customers. To ensure adequate oversight, PHMSA works cooperatively with state and local regulatory agencies such as the California Public Utilities Commission (CPUC or "Commission") that are responsible for safety oversight of all intrastate natural gas pipelines, such as those operated by both SoCalGas and SDG&E. This cooperative effort is the cornerstone for assuring uniform implementation of PHMSA's pipeline safety program nationwide. To achieve this goal, PHMSA conducts a broad safety assessment and regulatory program focused on understanding the risks from and to pipelines, and on developing rules and standards necessary to address those risks. As part of its safety assessment, PHMSA now employs a compliance and enforcement program that is concerned principally with performance assurance. Nevertheless, the primary concern has always been the safety of the pipeline operating system, not the presence or absence of records.

As Associate Administrator with RSPA from 1989-1995, I was responsible for enforcing safety regulations governing the pipeline transportation of natural gas and hazardous liquids. I also created cooperative risk management task forces charged with developing a risk management focus for federal pipeline safety regulations and compliance. These efforts formed the foundation of the current integrity management components of the federal regulations. Additionally, I served as a spokesperson for the RSPA and the Department regarding pipeline failures of national significance.

Following my tenure with the Department, I worked for two years as a strategic advisor on pipeline risk management planning for Battelle Memorial Institute, the world's largest nonprofit research and development organization. Thereafter, I worked for two years as a private consultant on pipeline integrity programs and planning.

From 1999 until my retirement in 2011, I served as President and Chief Executive Officer of Pipeline Research Council International, Inc. (PRCI). PRCI is the leading collaborative research development organization in the pipeline industry, comprised of 36 natural gas and hazardous liquid pipeline operators, including SoCalGas and SDG&E, and 22 associate members worldwide. Since its inception in 1953, PRCI has established a strong presence in pipeline research, and from 2002-2011 it was the largest single funding partner with the Department's research program.

Since retiring, I have remained actively involved in the pipeline industry as an advisor to both public and private enterprises concerning issues of emergency planning and response systems, as well as pipeline inspection. Specifically, I served on a blue ribbon panel to review the emergency planning and response program of PG&E and make recommendations for improvement in the wake of the San Bruno accident. I also currently serve on a panel of the National Academy of Sciences, Transportation Research Board to develop a pipeline study solicitation requested by the Department.

B. Purpose of Testimony

I offer this rebuttal testimony to provide the perspective of an individual with nearly twenty years of pipeline safety regulatory experience. My testimony responds to the recommendation of several witnesses—sponsored by or relying on the work of the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), the Consumer Protection and Safety Division (CPSD), and the Southern California Indicated Producers (SCIP)—that shareholders should bear varying degrees of financial responsibility for pipeline testing and replacement because of the absence of sufficient pressure testing records to meet certain industry and regulatory standards that have varied over time in scope and substance.[1] I understand that the recommended extent of shareholder financial responsibility varies among these witnesses, but it is their common rationale that I wish to address, i.e., if an industry standard or regulation can be interpreted as requiring the retention of pressure test records, then the lack of such records justifies imposing on shareholders the cost of newly ordered pressure tests and pipeline replacement.

At the outset, I want to clarify my approach to assessing this rationale. In my role as a federal safety regulator, I was not required or requested to consider whether any monetary sanction would be financed by shareholders or ratepayers. It was my role and mandate to assess penalties, including both fines and compliance orders, with the primary goal of achieving future compliance. Consequently, for the purpose of this testimony, I am equating the recommended transfer of costs from ratepayers to shareholders to the imposition of a substantial economic penalty.

As discussed below, that recommendation is unwise for several reasons. It is inconsistent with established regulatory direction regarding the importance of compliance and the consequences of noncompliance; it makes retention of pressure test records more important than substantive operator safety practices or other records that may be as or more indicative of pipeline integrity; it ignores the fact that a lack of test records is not itself an indication of wrongdoing or unsound safety practices by an operator; and it overlooks the value of an

[1] DRA Report on the Proposed Natural Gas Pipeline Safety Enhancement Plan of Southern California Gas Company and San Diego Gas & Electric Company, pp. 10-16; Prepared Testimony of Thomas J. Long, TURN, pp. 14-23; Technical Report of the CPSD Regarding the Southern California Gas Company and San Diego Gas and Electric Company Pipeline Safety Enhancement Plan, p. 24; Prepared Direct Testimony of R. Thomas Beach on Behalf of SCIP and Watson Cogeneration Company, pp. 18-21.

operator's contributions to safety and the community outside of its core operations. These are the standards that historically have been applied by regulators to determine the efficacy of assessing a substantial economic sanction against an operator.

II. BEFORE IMPOSING MONETARY PENALTIES ON OPERATORS FOR NON-COMPLIANCE, REGULATORS SHOULD ENSURE THAT REGULATIONS PROVIDE CLEAR DIRECTION OF THE CONDUCT REQUIRED AND THE CONSEQUENCES OF FAILING TO COMPLY WITH THOSE REQUIREMENTS

The pipeline industry is subject to a myriad of standards, rules, and regulations, many of which were developed and implemented by different industry and regulatory bodies at different points in time (e.g., federal and state safety, environmental, and economic rules). In light of these numerous rules and regulations, before assessing significant monetary penalties against a pipeline operator for noncompliance, it is imperative that the rules and regulations clearly communicate what is expected of an operator. The regulations also should make clear that noncompliance will subject pipeline operators to substantial economic sanctions.

With respect to the subject of test records, it was commonly understood among regulators that safety records, including test records, might be missing given the passage of time and other intervening events. And there was certainly no indication that a failure to preserve such records would result in the assessment of substantial economic penalties. Thus, SoCalGas' failure to preserve some hydrostatic pressure testing records prior to any express regulatory requirement clearly does not justify penalizing the company with the costs of newly ordered pressure tests pursuant to the PSEP. Nor does the lack of such records, even in the face of arguably clearer standards, warrant a penalty equal to *all* costs associated with pipeline pressure testing and possible replacement required because adequate documentation is not available. This is particularly true where, as discussed in the following section, the safety and reliability of the pipelines can be otherwise ascertained.

In the absence of clear regulatory direction concerning the conduct required of a pipeline operator and the consequences of failing to comply with those requirements, there is no justification for penalizing shareholders by requiring them to pay for costs customarily borne by ratepayers.

III. HOLDING SHAREHOLDERS RESPONSIBLE FOR COSTS ASSOCIATED WITH THE PSEP FAILS TO RECOGNIZE THAT TEST RECORDS ARE NOT A SUBSTITUTE FOR AN OPERATOR'S SAFE OPERATION

The intervenor and staff witnesses assert that determining whether shareholders should bear the cost of pressure testing and possible pipeline replacement necessitated by the PSEP is easily and adequately resolved simply by looking to certain language in industry standards, as well as governing federal regulations and CPUC General Orders. But assuming these provisions all appear to require indefinite retention of test records (which they do not), the absence of required records should not itself dictate whether the assessment of a substantial economic sanction against an operator is justified. The Commission's desired outcome—the safe operation of the SoCalGas and SDG&E pipeline systems—involves a multi-faceted, risk-based safety program (including ongoing expenses associated with operation, maintenance, inspection, and testing), the costs of which are typically the responsibility of ratepayers. Before altering the traditional system by which costs are assessed to ratepayers, and effectively imposing a monetary penalty on shareholders, it is essential to look more broadly at the pipeline operator's business practices, operating history, risk assessment and management, and emergency preparedness and response. If an operator has a demonstrated history of operating safe pipelines and responding swiftly and efficiently to system risks and failures, then both the operator and regulator can have confidence in the reliability and safety of the pipeline. Thus, where there are other, contemporaneous means of evaluating the soundness of a pipeline system, the absence of historic hydrostatic testing records is of limited relevance. A pipeline's safety can be better determined by an examination of the operator's operational and risk management history.

This is not to say that test records are without value. It *is* to say that the value and relevance of test records are, in large part, risk-dependent. Therefore, where the pressure stability of a pipeline can be adequately assessed through means other than the examination of historic hydrostatic testing records, there is no reason to believe that those records are essential to determining the safe and prudent operation of the system. And it is certainly no reason to require the extraordinary result of imposing substantial economic sanctions on an operator by shifting financial responsibility for operational services from ratepayers to shareholders. The intervenor and staff witnesses give no consideration to SoCalGas' or SDG&E's safe and effective operation of their systems, instead recommending that the Commission analyze the governing recordkeeping rules and regulations in a vacuum. The Commission should decline to do so.

It is my understanding that the Commission is requiring California natural gas pipeline operators to pressure test or replace pipelines that do not have sufficient documentation of a pressure test,[2] and several intervenors have provided testimony that suggests that natural gas pipeline operators should have "traceable, verifiable, and complete" records as enunciated in the NTSB January 3, 2011, safety recommendations to PG&E for pipelines prior to when the federal

[2] D.11-06-017, Ordering Paragraph 4.

regulations went into effect.[3] Requiring the pressure testing or replacement of in-service pipelines would, as the Commission acknowledges in its Decision, do away with reliance on the grandfathering clause to establish maximum allowable operating pressure, and thus establishes a new standard in the industry.

It is important to note that the "traceable, verifiable and complete" standard enunciated by the NTSB is new to the natural gas pipeline industry and significantly different from the standard that federal and state regulators have traditionally used in administering their safety programs. As discussed, records are but one thread in the regulatory fabric that overlays the safe operation of a given pipeline. Thus, the focus should not be on the mere existence of traceable, verifiable and complete test records, but on whether the records are indispensable to demonstrate the current safety of the operation. Indeed, this is the standard that was employed during my career as a federal regulator.

In the case of pressure stability, the safety and integrity of a pipeline can be readily determined by considering a number of factors wholly apart from records of hydrostatic pressure testing at the time of construction. Key among them are the pipeline operator's practices, the extent of the pipeline's corrosion protection, whether adequate monitoring and leak detection systems are in place, and, where technically feasible, the operator's use of in-line inspection tools. By contrast, where a pipeline is buried on an unstable slope, and the issue of pipeline safety is one of slope stability, the absence of construction and maintenance records reflecting soil conditions, both at the time of construction and over time, is of much greater concern because those records are *indispensable* to evaluating whether the slope can adequately support the safe operation of the pipeline.

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[3] NTSB Safety Recommendation P-10-3 (Urgent).

Thus, the significance of test records is directly dependent on the risk involved. Where, as here, there are other ways to assess the integrity and reliability of SoCalGas' and SDG&E's pipelines, the existence of hydrostatic pressure testing records becomes significantly less relevant and certainly should not be determinative in deciding to impose a penalty.

IV. IMPOSING PSEP OPERATIONAL COSTS ON SHAREHOLDERS IGNORES THE FACT THAT THE ABSENCE OF TEST RECORDS DOES NOT REFLECT THE TYPE OF CONDUCT THAT MERITS A SUBSTANTIAL MONETARY PENALTY

It is important to keep in mind that the test records at issue would be 50, 60, and in some instances more than 70 years old. Considering the age of those records, any gaps in recordkeeping can be explained by a host of circumstances that would not amount to willful misconduct, gross negligence, or a consistently bad business practice by SoCalGas—conduct typically meriting the imposition of significant monetary penalties. As discussed above, regulators should not impose such penalties absent clear regulatory direction on the conduct required and the consequences of noncompliance. The typical consequence in my experience at RSPA was the issuance of a compliance order (sometimes accompanied by a *de minimis* monetary fine), *not* the wholesale assessment of costs associated with bringing the operator into compliance.

Examples of when a substantial penalty may be warranted could include a pipeline operator operating outside the scope of its O&M or risk management plans; the operator's failure to comply with an order to perform certain work; affirmative misrepresentations to the regulatory body; or failure to act on information generated by its operations and maintenance program that indicates the presence of a problem. In such circumstances, a regulator properly determines whether a substantial economic penalty should be imposed on the operator. And in my experience, the largest penalties were reserved for the most egregious conduct and consequences of substantial impact.

Gaps in recordkeeping unrelated to a demonstrable problem simply do not rise to this level of misconduct. To the contrary, missing records of this vintage are not uncommon among the most prudent pipeline operators such as SoCalGas. Indeed, RSPA's risk management effort was a direct response to this reality. With a pipeline infrastructure in some cases more than 90 years old, regulators frequently encounter missing records. It was for this reason, in part, that regulators needed to look beyond records in determining a pipeline system's operational safety and integrity. And because missing records were a common occurrence, it was *un*common in my experience to impose upon an operator the type of substantial monetary penalty recommended by the intervenor and staff witnesses here.

V. SOCALGAS HAS AN EXCELLENT REPUTATION IN PIPELINE SAFETY AND IS A LEADING PARTICIPANT IN PIPELINE RESEARCH

As the lead federal regulator for pipeline safety, I had occasion to examine SoCalGas' operational system, its compliance practices, its overall safety record, and its corporate contributions to enhancing pipeline safety—all of which reflect the excellent reputation of SoCalGas in the natural gas industry. Not surprising to me is the fact that the company's safety record had been greatly facilitated by California's ratemaking regime, which allows operators and utilities to incorporate their ongoing operating costs—including for inspection and testing—into their rates. However, it is shareholders who bear the expense of extending this tradition of safety performance and operational excellence beyond the company and the State in such matters as industry standards development, crisis support (e.g., the technical assistance provided to

Japanese utilities in the wake of devastating earthquakes in that country in the 1990s), and best practices. In my view, SoCalGas has led the charge in these significant respects.

As President of Pipeline Research Council International, I also have worked with SoCalGas corporate executives and technical experts to research issues related to natural gas transmission systems, pipeline safety, and the development of industry standards that have been adopted outside the United States (e.g., operating practices to address geophysical threats to pipelines). SoCalGas has been a leading participant in this research and when one considers the total miles of transmission pipeline that the Company operates, it traditionally has been among the largest financial contributors to PRCI. As important to PRCI, however, has been SoCalGas' leadership, which includes its chairing at least one of PRCI's technical committees since 2000, and its holding the chairmanship of PRCI from 2004-2007, during which time the organization grew by twenty percent.

VI. CONCLUSION

The considerations that underpin pipeline safety regulation are as varied and complex as the pipeline operations they address. As such, they cannot be viewed through the single lens of records and recordkeeping. Rather, it is necessary to consider the overall reliability of an operator's pipeline system. Where a required record is not essential to determining the reliability of a pipeline, its absence should not serve as the basis for imposing substantial monetary penalties. SoCalGas and SDG&E are taking steps, pursuant to the PSEP, to conduct pressure testing of some of their pipelines to ensure the *continued* reliability of their systems. This approach reflects sound and prudent business practices; it in no way reflects the type of nonfeasance or misfeasance that has historically led regulators to assess large economic sanctions against pipeline operators.

CHAPTER 4

SAFETY AND OPERATIONAL CULTURE

AT SOCALGAS AND SDG&E

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PREPARED REBUTTAL TESTIMONY

OF LEE STEWART

Southern California Gas Company (SoCalGas) and its predecessor companies have a long record of industry leadership in the pipeline industry. I spent 43 years working on the operations side of SoCalGas, with direct officer level responsibility for transmission infrastructure design, construction, operation and maintenance for the latter half of those years. From 1998 to 2010, I was also responsible for the San Diego Gas & Electric Company (SDG&E) transmission system. The purpose of my testimony is to provide a perspective of SoCalGas' excellence throughout the period of rapid expansion of Southern California's dependence on natural gas to SoCalGas' current role as the custodian of a mature pipeline system. This perspective is intended to rebut the testimony of intervenors suggesting that the absence of some pressure testing records necessarily equates to an unsafe system, and therefore, it is appropriate to make shareholders pay to pressure test and replace pipelines. SoCalGas has never had a careless attitude toward safety. In fact, the opposite is true. Although my tenure with SDG&E was more recent, that same commitment was exhibited there.

At SoCalGas, I initially learned and observed, then later perpetuated and cultivated a culture of operational excellence, founded on safety, reliability, and efficiency. Observations of management from early in my career made clear that the company's safety focus and values began long before my tenure.

Application of state of the art technology and operator excellence was evident from the construction of the 26-inch diameter "Big Inch" pipeline that brought gas from the San Joaquin Valley to Los Angeles in 1931, and the 30-inch diameter "Biggest Inch" pipeline that brought Texas gas to California in the late 1940's. As a testament to the diligence of these pioneers, much of these systems continue to safely move gas in the region today. SoCalGas has consistently embraced and applied technology to create a system that delivers safe, reliable and efficient service to its customers.

I. SAFETY HAS BEEN A TOP PRIORITY AT SOCALGAS

Operating a high pressure pipeline system in a populated region such as Southern California requires constant vigilance. The process involves paying attention to a myriad of details from design, material selection, installation, inspection, testing, and commissioning, followed by controlling the operation and maintaining the pipeline. These factors have been comprehensively managed at SoCalGas. An anecdotal measure of effectiveness of the SoCalGas process is that I cannot recollect a significant public safety incident attributable to the performance of the transmission system.

A secondary measure of ongoing process effectiveness is in the record of the Commission's Consumer Protection and Safety Division (CPSD) audit reports covering transmission over the years. These comprehensive audits, normally ten days in duration, are done by CPSD safety engineers and include field site visits as well as comprehensive reviews of inspection and maintenance records. I reviewed fifteen post-2001 audit reports from SoCalGas and ten from SDG&E covering in excess of 100,000 inspection items. There were eleven findings related to non-compliance with regulations, all of which were minor and did not result from any systemic process flaws. To provide a perspective, this rate of compliance far exceeds the 95% inspection compliance level that was stipulated by the Commission and SoCalGas satisfactory in the mid-1980's.[1] It is evident that SoCalGas takes seriously its compliance responsibility.

Staying ahead of the safety curve is another important indicator of SoCalGas' excellence as a system operator. Evaluating the system and determining areas requiring special focus has led to the development of several special pipeline replacement programs that SoCalGas developed to update the integrity of its distribution and transmission infrastructure. In the mid-1980's, SoCalGas initiated a special pipeline replacement program focused on non-state of the art infrastructure that presented elevated risk to public safety. Following approval by the Commission, this $300 million program substantially eliminated several families of distribution pipe, such as cast iron, copper, and PVC plastic, as well as several gas welded, pre-World War II transmission pipelines in populated areas subject to earthquake stresses. When this program was completed in the mid-1990's, a follow-on internal process called System Integrity Program (SIP) was developed to further examine and screen older families of infrastructure including pipelines that, although operated at relatively low stress levels, concerned operating personnel because of leakage history or construction materials.

Another example is the systematic approach initiated by SoCalGas in the 1990's to improve the earthquake resistance of critical transmission pipelines that cross active earthquake faults. First, SoCalGas engineers located and mapped all known active earthquake faults within the SoCalGas territory. Second, SoCalGas used the fault maps to evaluate and improve existing critical pipeline crossings, as well as a screening tool to avoid or design for fault crossings of new pipelines. By enhancing the performance of pipelines crossing earthquake faults through

[1] D.84-12-069 (Jan. 7, 1985) required SoCalGas to implement "system safety improvement steps" outlined in an exhibit to the decision. This agreement did not contemplate that perfection in inspection records would be required. Rather, "noncompliance items will not exceed 5% of all items inspected annually." Stipulation and Agreement in A. 84-02-25 dated September 20, 1984 at ¶ 7.

the use of modern design techniques such as stronger pipe material, optimized pipeline crossing angles, special trench configurations and backfill materials, and friction-reducing geosynthetic fabrics, SoCalGas has reduced the risk of failure, enhancing public safety as well as system reliability. At this time, seven existing fault crossings have been modified and six crossings of new pipelines have been constructed using these enhanced design techniques. Several more existing fault crossings have been evaluated and were determined capable of withstanding the anticipated ground displacement in a probable earthquake event.

Recent evidence of SoCalGas and SDG&E's commitment to safety is the conservative approach taken to comply with the federally mandated Transmission Integrity Management Program (TIMP) beginning in 2002. In response to federal requirements mandating baseline inspection of transmission pipelines, SoCalGas and SDG&E developed a prudent strategy and program based on extensive retrofitting of existing pipelines and internal inspection of its gas system using "smart-pigs." Although an inspection program using "smart-pigs" was substantially more capital- and time-intensive, SoCalGas and SDG&E chose this method because its technical staff determined that the pigging technique, by actually contacting the pipeline steel, provided a much greater capability to detect potentially hazardous anomalies that may be present in older pipelines. This was a critical commitment that defined SoCalGas and SDG&E's commitment to pipeline safety. Other techniques such as external corrosion direct assessment (ECDA) have been used on a limited basis where corrosion was the principal factor of concern. In addition to the broader spectrum of issues detectable through pigging, the baseline assessment obtained can be referenced in subsequent assessments to determine if the system condition is deteriorating, and, if so, at what rate.

As presented in the SoCalGas and SDG&E Amended Pipeline Safety Enhancement Plan (Dec. 2, 2011) at 15, 833 miles (63%) of the total baseline assessment of pipeline segments in High Consequence Areas (HCA) was already completed through December 2010 using in-line inspection with smart pigs. This contrasts with the PG&E pipeline integrity plan that called for a total of 208 miles (20%) of HCA miles to be completed using in-line inspection (pigging). *See* National Transportation Safety Board Accident Report – PG&E's Natural Gas Transmission Pipeline Rupture and Fire, NTSB/PAR-11/01, PB2011-916501 (Sept. 9, 2010) at 63.

II. SOCALGAS IS AN INDUSTRY LEADER IN FUNDING FOR PIPELINE RESEARCH

SoCalGas' long-term commitment to safe and prudent operations is evidenced by its more than 50 years of continuous participation in the Pipeline Research Council International (PRCI) (previously the Pipeline Research Committee of the American Gas Association). Through this collaborative organization, SoCalGas has been part of developing the pipeline industry's ever-improving technologies including welding, non-destructive evaluation, earthquake design, and evaluation of fitness for service of older pipelines.[2] Although SoCalGas is a mid-sized pipeline operator when measured by miles of pipe in the PRCI arena, SoCalGas is a major contributor of both engineering talent and funding of this critical voluntary industry

[2] Research projects championed by SoCalGas include: 1) Effects of Non-typical Loading Conditions on Buried Pipelines, 2) Guidelines for the Seismic Design and Assessment of Natural Gas and Liquid Hydrocarbon Pipelines, 3) Static and Dynamic Analysis of Highly Tensioned Suspended Pipeline Spans, 4) Acceptance Criteria for Mild Ripples in Pipeline Field Bends, 5) Guidelines for the Design, Construction, Inspection and Maintenance of Cable Supported Pipeline Bridges, 6) Wrinkle Bend Integrity Study on Gas and Liquid Pipelines, 7) Effectiveness of Geosynthetic Fabric Interfaces in Reducing Soil Loads on Buried Pipelines, 8) Effects of Static and Cyclic Surface Loadings on the Performance of Welds in Pre-1970 Pipelines, 9) Automated Detection of Subsidence Ground Movement Using Satellite Remote Sensing, 10) Enhanced Model and Practice Guideline for Horizontal Directional Drilling, and 11) Guidelines for Managing Risks to Pipelines Through Landslide and Subsidence Hazard Areas.

effort. On a per transmission mile basis, SoCalGas is the highest funding member of this organization.

III. SOCALGAS AND SDG&E COMPLY WITH AND CONTRIBUTE TO CHANGING STANDARDS AND REGULATIONS

The natural gas industry has become safer over the years through the introduction and continuing evolution of industry standards, code provisions, and regulations. SoCalGas and SDG&E have not sat idly by and let this process evolve, but have consistently been at the table providing knowledge, experience and funding to these efforts. On most federal pipeline safety rulemakings, SoCalGas and SDG&E provide their own direct comments as well.

Once new regulations are approved, SoCalGas and SDG&E incorporate them into their O&M plans, operating procedures, and scheduling systems. These changes are reviewed on an annual basis by CPSD to see that appropriate revisions have been undertaken and are properly executed in ongoing O&M activities.

IV. INCOMPLETE RECORDKEEPING

Neither SoCalGas nor SDG&E have pressure test records for every pipeline segment in their systems. Based on my experience, this is not unusual given the time that has lapsed and the changes that have taken place within the company. Prior to 1955, no recordkeeping requirement even existed. Explanations for documents not retained after that time can be no more than human error, or relocation of offices, merger of companies, misfiling, mislabeling of archive documents, as well as possible fire and water damage. These circumstances are typical throughout the industry and were recognized in the adoption of the "Grandfather Clause" in 1970 in 49 CFR 192.619(c).[3]

Part 192 prescribes the minimum safety requirements for pipeline facilities and the transportation of gas, including regulations governing the establishment of the maximum allowable operating pressure (MAOP). Part 192 contained what is commonly referred to as a "Grandfather Clause" for establishing the MAOP of pipelines placed in-service prior to 1970.

In response to the 1970 regulations, SoCalGas went through pipeline pressure records to establish an MAOP consistent with Part 192. If there were operational flexibility issues or capacity concerns, uprating or retesting was done to re-establish a higher MAOP consistent with the regulation. However, in most cases, the MAOP established by the five years of operational records was sufficient to meet SoCalGas' customer needs. Once the review was completed, a new MAOP master book was developed which, unless a higher MAOP was needed, mitigated the need for prior pressure test records.

In my experience, regulators have never required 100% compliance with documentation standards; they have noted discrepancies and required correction where feasible but have never used imperfect records as the basis for large-scale penalties. Even though the stipulation between the Commission and SoCalGas discussed above referenced discrepancies in inspection records, the stipulation recognizes that attaining perfection is unreasonable.

Moreover, SoCalGas' inability to locate all pressure testing records is not evidence that SoCalGas did not test pipelines or an indication of a safety issue. The Grandfather Clause in Part 192 assured that lines did not operate at pressures higher than historically safe. If there was a

[3] *See* Rebuttal Testimony of Michael Jay Rosenfeld beginning at page 16 for a detailed explanation of grandfathered pipelines.

need to go to a higher pressure, the absence of pressure test records would have dictated a retest under Part 192. Indeed, when Part 192 was first implemented, SoCalGas filed Application No. 52296 seeking five additional months to comply with the new MAOP provisions in Part 192. The Commission staff conducted an investigation and concluded that “there is no evidence that the system is being or will be operated in an unsafe manner, and that [SoCalGas’] request [for an extension of time to comply with the MAOP provisions in Part 192] should be granted.” D.79502 (Dec. 21, 1971) at 6.

V. CONCLUSION

Although my career in the SoCalGas transmission organization was long by many measures, the culture of the transmission organization was set many years ago, at the time when the Big Inch and Biggest Inch pipelines were being built. There was an esprit de corps that went with being a small organization, with highly trained and skilled personnel, managing a high risk asset. As the company grew, its commitment to safety and operational excellence remained. SoCalGas and SDG&E’s culture is not to take risk, but to manage risk by applying state of the art technology, following sound engineering practice, and maintaining the system in accordance with the well-established regulations.

In my experience at SoCalGas and SDG&E, the companies maintained a rule-following culture in the inspection, maintenance, and repair of their pipelines to comply with applicable laws and standards – often exceeding them. SoCalGas’ history demonstrates its industry leadership in safety innovations and the prudent, conservative approach it has taken to operations. Although my tenure with SDG&E was more recent, the same commitment was exhibited there.

CHAPTER 5

HISTORY OF PRESSURE TESTING AND RECORDKEEPING REQUIREMENTS

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PREPARED REBUTTAL TESTIMONY

OF MICHAEL ROSENFELD

I. INTRODUCTION

A. Summary of Conclusions

My conclusions are summarized as follows:

1. Pressure testing of pipelines after construction has not always been practiced historically. Pressure testing practices and requirements have evolved over time. At various times, pressure testing requirements have differed among individual pipeline operators, recognized industry-developed standards, state regulations, and Federal regulations.

2. Recordkeeping requirements as they pertain to pressure testing, establishing the MAOP, and other elements of the design and construction of pipelines have not always existed. Recordkeeping requirements as they relate to these matters have evolved over time. At various times, recordkeeping requirements have differed among individual pipeline operators, recognized industry-developed standards, state regulations, and Federal regulations. Until recent times, such requirements have lacked substantial specificity and pipeline regulators have not emphasized recordkeeping practices outside of the specific provisions contained in the applicable regulations.

3. Pipeline regulators have long recognized that significant potential for gaps in records exists. This recognition was embodied in the allowance of "grandfathered pipelines" having maximum allowable operating pressures (MAOPs) established by prior operation, rather than documented testing or calculations requiring original engineering documents. Regulatory allowance of methods for establishing the MAOP in existing pipelines without a historic pressure test or without complete records of engineering details of the piping system has persisted to the

present. Recognition that data may not be available is also evident in regulatory requirements for integrity threat identification and risk assessment in connection with integrity management plans.

4. Requirements that pipeline records be "traceable, verifiable, and complete" are new. These terms as they relate to pipeline records did not originate with the primary pipeline regulator, and have not previously been articulated within the historical pipeline regulations or industry standards that preceded them. That the pipeline regulator has long recognized that gaps could exist in records is inconsistent with the notion that records have always been required to be "traceable, verifiable, and complete."

B. Qualifications

I am qualified to submit this testimony by training, and experience as a mechanical engineer since 1979. I have been employed since 1991 by Kiefner & Associates, Inc. (KAI) in Worthington, Ohio, a consulting firm that provides technical services to oil and gas pipeline operators and pipeline industry groups, including pipeline failure investigations, fitness for service assessment, integrity assessment procedures, engineering analysis, risk assessment, codes compliance, research, training, and other services. My current position is Vice President and General Manager following acquisition of KAI by Applus-RTD, an international certification and inspection company. Prior to that, I was President of KAI for 10 years.

During my employment with KAI, I have provided consultation to numerous oil and gas pipeline operators in technical matters related to pipeline fitness for service, integrity assessment, remaining life estimation, design, repairs, failure investigations, risk, materials selection, fracture control, welding, and compliance to standards and regulations, among others. I have also conducted several research projects on matters related to pipeline integrity for various pipeline industry research groups, including the Pipeline Research Council International (PRCI), the Gas

Technology Institute (GTI), and the American Society of Mechanical Engineers (ASME). I am a member of the ASME B31.8 Section Committee since 1994, and was Vice Chair of the committee for 4 years. I am also a member of the ASME B31 Mechanical Design Committee since 1990, a member of the ASME B31 Standards Committee since approximately 1999, and the ASME Board of Pressure Technology Codes and Standards since 2008. I am also the instructor for ASME Continuing Education's Professional Development course on the ASME B31.8 standard, and was awarded ASME Fellow in 2012.

Prior to joining KAI, I was employed for 6 years by Battelle Memorial Institute, Columbus, Ohio, a research and development organization. During that time I performed engineering analysis in a broad range of industrial and defense projects, including research on pipeline integrity matters for natural gas pipeline operators and for PRCI. Prior to joining Battelle, I was employed for 4 years at Impel Corporation in Melville, NY performing stress analyses of nuclear power plant piping systems, equipment, and structures for seismic and other conditions.

I am a registered Professional Engineer in the State of Ohio.

C. Documents Reviewed

My analysis and conclusions are based on a review of various external documents. The documents that I relied on to prepare this testimony include, in no particular order:

- ASME B31.8 "Gas Transmission and Distribution Piping Systems" and its predecessor standards, various editions;
- Supplement to ASME B31.8, "Integrity Management of Gas Transmission Pipelines," B31.8-S, various editions;
- Code of Federal Regulations, Title 49 – Transportation, Subtitle B – Other Regulations Relating to Transportation (Continued), Part 192 – Transportation of natural and other gas by pipeline: Minimum Federal safety standards, 49 CFR 192, various years;
- Preamble, Part 192, Original Document, Federal Register, Vol. 35, No. 161, Wednesday, August 19, 1970, Pages 13246 to 13278;

- General Order No. 112 of the Public Utilities Commission of the State of California, “Rules Governing Design, Construction, Testing, Maintenance and Operation of California Utility Gas Transmission and Distribution Piping Systems,” various years;
- “GPTC Guide for Gas Transmission and Distribution Piping Systems,” ANSI Z380.1, various years;
- Hough, F.A., “The Gas Industry has Approved its New Safety Code,” Gas Magazine, November 1954;
- Hough, F.A., “The New Gas Transmission and Distribution Piping Code” (ASA B31 Section 8), Series in 8 Parts, Gas Magazine, January through September 1955;
- Jennings, W.C., “The Regulator’s Handbook,” June 1971;
- Bergman, S.A., “Why Not Higher Operating Pressure for Lines Tested to 90% SMYS?” Pipeline and Gas Journal, December 1974;
- Castaneda, C.J., and Pratt, J.A., <u>From Texas to the East: A Strategic History of Texas Eastern Corporation</u>, Texas A&M University Press, 1993;
- Elder, L.L., “The History of the Gas Piping Standards/Technology Committee,” GPTC/GPSRC 25th Anniversary Meeting, July 17-20, 1995;
- McGehee, W.B., “Maximum Allowable Operating Pressure (MAOP) Background and History,” Report to Gas Research Institute, March 5, 1998;
- Shires, T.M. and Harrison, M.R., “Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implications for Today’s Natural Gas Pipeline System,” GRI-98/0367.1, December 1998;
- Kiefner, J.F., “GRI Guide for Locating and Using Pipeline Industry Research: Section 4, Hydrostatic Testing,” Gas Research Institute, GRI-00/0192.04, March 2001;
- Safety Recommendation P-10-2, to Pacific Gas and Electric, National Transportation Safety Board, January 3, 2011;
- California Public Utilities Commission, “Decision Determining Maximum Allowable Operating Pressure Methodology and requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans,” Rulemaking 11-02-019, Issued 06/16/11;
- PHMSA Advisory Bulletin, “Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation,” ADB-2011-11;
- PHMSA Advisory Bulletin, “Pipeline Safety: Verification of Records,” ADB-2012-06;
- “Industry Guidance on Records Review for Re-affirming Transmission Pipeline MAOPs,” American Gas Association, October 2011;
- “Verification of MAOPs for Existing Steel Transmission Pipelines,” American Gas Association, April 2011.

II. DISCUSSION AND ANALYSIS

The focus of this testimony is pressure testing requirements and recordkeeping requirements in gas pipeline standards and regulations, historically and currently, nationally and in the State of California. This testimony will describe the evolution of pipeline pressure testing requirements, what records have been specifically required, how those records relate to establishing the maximum allowable operating pressure (MAOP) of a pipeline, why so-called "grandfathered" pipelines have existed, and the significance of recently articulated criteria for records accuracy.

A. Standards and Regulations Development

1. Family Tree

The evolution of modern pipeline standards can be traced to the B31 Code for Pressure Piping, Standard B31.1, first published as a tentative standard by the American Standards Association (ASA), a predecessor to the American National Standards Institute (ANSI), with sponsorship of the American Society of Mechanical Engineers (ASME). This standard covered the materials, design, and fabrication of piping systems with industry-specific sections for power piping, gas and air piping, oil piping, and district heating piping. The scope of Section 2 covering gas and air piping systems included city gas distribution systems, and cross-country gas pipelines and compressor stations. ASA B31.1 was updated and republished in 1942, 1947, and 1951.

The gas pipeline industry perceived a need to further develop the standard to better address the technical requirements for buried natural gas pipelines, which differ substantially from the technical issues associated with above-ground piping systems within facilities such as power plants that tended to dominate technical development of the standard. This perception was further stimulated by a widely publicized gas distribution system incident in Rochester, NY in 1950 and concern for a consequent regulatory response.[1] In response, Section 8 of the 1951 B31.1 addressing only natural gas pipelines was approved and published as a stand-alone document in 1952. Although it drew largely on the technical requirements for gas and air piping in Section 2 and selected fabrication details from Section 6 of the 1951 B31.1 standard, the publication separately from B31.1 provided the platform for further development of a more comprehensive pipeline-specific technical standard.

The 1955 edition of Section 8, identified as B31.1.8, represented a thorough rewrite and significant technical advancement in requirements for natural gas transmission and distribution piping systems. It incorporated a risk-informed design basis in the form of a location class scheme based on the number of dwellings intended for human occupancy near the pipeline, significantly more guidance relevant to the design and installation of cross-country transmission pipelines and gas distribution systems, and rigorous new pressure testing requirements. It was thought that a well-conceived technical standard for pipelines could serve as useful input to state pipeline safety regulations.[2] Elements of the 1955 standard are still evident in the current edition. The standard was revised and republished as B31.8 in 1958, 1963, and 1968 prior to the issuance of pipeline safety regulations by Department of Transportation (DOT) in 1970. Addenda were issued in some years between editions. B31.8 continued to be revised and periodically republished after 1970 to the present time.

The Public Utility Commission of the State of California enacted General Order 112 (GO 112) with an effective date of July 1, 1961, specifying minimum rules for the design, construction, operation, and maintenance of natural gas pipelines within the state. GO 112 incorporated substantial portions of the 1958 edition of B31.8, omitted portions in conflict with

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[1] Elder.
[2] Hough, 1954.

CPUC requirements, and provided additional language where necessary to accomplish its goals as the utility regulator. Incorporation of suitable portions of B31.8 was one of ASA's purposes in publishing the standard. Subsequent issuances of GO 112 in 1964 and 1968 incorporated significant portions of the most-current edition of B31.8 until DOT issued its gas pipeline regulations in 1970. Subsequently, GO 112 incorporated the DOT regulations.

In response to a significant gas pipeline incident in Natchitoches, LA in 1965, the Natural Gas Pipeline Safety Act (NGPSA) of 1968 authorized DOT to create the Office of Pipeline Safety (OPS, predecessor to the present Pipeline and Hazardous Materials Safety Administration, or PHMSA), enact interim safety standards within 3 months consisting of existing State safety standards, and issue Federal pipeline safety regulations within 24 months. Interim regulations comprised of existing standards were imposed until complete regulations were adopted as Part 192, effective July 1, 1970. A review of the technical content of Part 192 shows a clear influence of B31.8, with revisions in language and additional content for clarity and enforcement. Part 192 does not make specific reference to B31.8 on most technical matters because it was the belief of the then-director of OPS that a regulation may be potentially compromised by referring to industry-developed standards.[3]

The NGPSA required the establishment of the Technical Pipeline Safety Standards Committee (TPSSC). The purpose of the TPSSC was to review all proposed pipeline regulations for "technical feasibility, reasonableness, and practicality."[4]

In 1970, ASME, with OPS's agreement, began publishing language from Part 192 supplemented with practices from B31.8 and other sources to guide operators in meeting the regulatory requirements. The publication was prepared by the Gas Piping Standards Committee

[3] Jennings.
[4] Fed. Reg., pg. 13256.

(GPSC) and known as the GPSC "Guide." In 1982, the administrative support transitioned to the American Gas Association (although it continued to be published by ASME), the committee name changed to the present Gas Piping Technology Committee (GPTC), and it acquired recognition as meeting ANSI criteria and was designated ANSI Z380.[5]

2. Standards Are Not Regulations

The foregoing discussion explains the origin of present-day regulations in contemporaneous industry-developed standards. Standards exist to provide technical guidance and promote uniformity in practices. In particular ASME B31.8 was intended to be a statement of what is generally accepted to be good practice,[6] written by engineers for an audience of other engineers, designers, managers, and regulators. Hence the standard cannot include practices that are not generally accepted even if they are superior, nor should it include practices that are considered unnecessary. The requirements set forth in B31.8 are considered adequate under conditions normally encountered, while unusual conditions are not specifically provided for. Also, it is not a law. The standard was intended to improve public safety through compliance by pipeline operators voluntarily and in good faith.[7]

A regulation is a legally enforceable requirement, as a government response to a problem. The regulation embodied in 49 CFR 192 was intended to prescribe what industry must do by stating the level of performance which it must meet, while leaving industry free to develop the specific means of meeting the prescribed level of performance.[8] In other words, regulation prescribes "what" while industry standards describe "how." Regulations are written by regulators for an audience of inspectors and the regulated entities for the purpose of enforcement.

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[5] Elder.
[6] Hough, 1955.
[7] Hough, 1954.
[8] Jennings.

Even though technical provisions in the regulations (GO 112 and 49 CFR 192) have their origins in technical provisions in the standard (B31.8), there are many areas in which the regulations and the standard do not agree, both historically and at present. These include matters of pressure design, material characteristics, hydrostatic pressure test levels and test duration, valve spacing, recordkeeping, and other elements of operation and maintenance.

B. History of Gas Pipeline Pressure Test Requirements

Hydrostatic pressure testing[9] is now a standard practice for commissioning a pipeline today but this was not always the case. The concept of pressure testing as a means of establishing the ability of pipe to safely contain pressure in operation was adopted from the vessel industry which had begun to implement that practice prior to 1900. However, pressure testing a natural gas pipeline that is many miles long (perhaps hundreds) with water is much more difficult than filling a vessel with water and these differences posed serious challenges to early pipeline operators, for a couple of reasons. One is that the large quantity of clean water necessary to fill the line cross-country was difficult to obtain and manage in any location and particularly so in dry-climate regions where many early large pipelines were constructed. The second problem was dewatering, since methods and tools to accomplish that had yet to be developed.[10] Consequently, up until the 1940's, if a pressure test was performed at all, it was usually accomplished using the transported commodity, natural gas in the case of gas pipelines, or crude oil or petroleum products in the case of liquid transmission pipelines. Owing to concerns for the consequences of a test failure (loss of product in the case of liquids, and loss of

[9] "Hydrostatic testing" means conducting a pressure test of a pipe or vessel using water as the pressurizing medium. However the term is also often used to refer to pressure testing using any fluid including gaseous media such as air, nitrogen, or natural gas. In this document, it is understood to mean a pressure test using any fluid except where a distinction is made with respect to the test medium.

[10] These same limitations existed for gas distribution systems. The quantities of water required are still large, and the networked nature of the systems complicates dewatering. Residual water in distribution piping is a problem for customers.

extensive quantities of pipe due to fracture propagation in the case of testing with natural gas), operators typically limited test pressures to between 5 psig and 50 psig above, or at most 10% above, their intended operating pressure.[11,12,13,14]

The first large-scale use of proof testing long-distance gas pipelines with water was carried out by the Texas Eastern Transmission Corporation in 1950.[15] In 1947 Texas Eastern acquired the two War Emergency pipelines built to transport crude oil and fuel from Texas to New Jersey during World War II, and converted them to transport natural gas. Texas Eastern experienced many service failures due to original pipe manufacturing defects which may have enlarged while in petroleum transportation service, and also due to corrosion because parts of the line were installed uncoated to save time. In 1950 Texas Eastern completed an ambitious program to revalidate the integrity of the pipelines by pressure testing them with water to levels well above the MAOP and in some cases up to yielding. Texas Eastern was able to do this because they had already developed cleaning pigs which were inserted in traps and were propelled by gas pressure to sweep accumulated liquids out of the line as part of the process of converting the lines from liquid to gas.[16] Although they experienced hundreds of test breaks,[17] the tested pipelines were reliable in subsequent years and portions of them are still in service today.[18] As a result of Texas Eastern's experience, between 1953 and 1968 the industry performed scientific studies to better understand the benefits, limitations, and mechanics of

[11] Kiefner.
[12] Hough, 1955.
[13] McGehee.
[14] Shires and Pratt.
[15] Castaneda and Pratt.
[16] Castaneda and Pratt.
[17] Bergman.
[18] Kiefner.

hydrotesting.[19,20,21] Over time, other operators began to consider or adopt the practice of hydrostatic testing with water to higher levels than had previously been customary.

The evolution of test requirements for commissioning a new pipeline system as they pertain to transmission pipelines constructed from steel pipe is summarized briefly below. (Testing requirements are not discussed herein for: low- and high-stress distribution piping, mains, and service lines; piping fabricated from plastic or cast iron pipe; testing for purposes of uprating; and testing to accommodate changes in location classes. The reason for omitting these requirements is they introduce significant complexity in details that are not central to the issue at hand.) Recordkeeping requirements in connection with testing are discussed with other recordkeeping requirements discussed in Part C of this submittal.

1. B31.8 Standard, Predecessors and Sequels

a. 1935 ASA B31.1, Section 2 Gas and Air Piping

§203 "Division of Systems" defined two categories of pipe based on location. Division 1 piping was air or gas piping constructed within power plants, gas plants, or manufacturing plants, or within the boundaries of cities or villages. Division 2 piping was constructed in compressor stations, installed cross-country, or outside boundaries of cities or villages.

§222 described pressure test requirements for Division 1 piping. Before installation, valves and fittings were to be "capable of withstanding a hydrostatic shell test" to designated pressures based on pressure rating classes similar to present-day pressure ratings for valves and flanged fittings. The ratio varied between 2.2 and 2.5. Pipe was to be "capable of meeting the hydrostatic test requirements" contained in listed pipe product specifications. After installation, piping systems containing welded joints were to be "capable of withstanding a hydrostatic test"

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[19] McGehee.
[20] Kiefner.
[21] Bergman.

to 1.5 times the service pressure, with the test to be applied where practical. §223 states that "if a test is performed" it must be in accordance with Clause 524 (found under Section 5, "Fabrication"). §524 permitted preliminary air or gas testing to 100 psig to check for leaks. During the hydrostatic pressure test, welds were to be struck by hammer blows to jar them.

§223 described pressure test requirements for Division 2 piping. Before erection, valves and fittings were to be "capable of withstanding a hydrostatic test pressure" to 1.5 times the rated maximum working pressure. Pipe was to be subjected to and safely withstand a mill pressure test in accordance with the pipe product specification, but not in excess of 90% of the yield point or yield strength of the material. There were no pressure test requirements post-installation. The working pressure was 80% of the pipe mill test pressure, or a percentage of the yield strength calculated as the seam joint efficiency factor divided by 1.4.

The language in the 1935 standard was understood to mean that testing of the pipe after installation was discretionary for Division 1 piping and not required for Division 2 piping. The wording "capable of withstanding a pressure test" was a design criterion calling for a combination of specified material strength grade and wall thickness of sufficient capacity to sustain pressure of specified amounts without impairment of the serviceability due to material failure or gross distortion. This is not the same as requiring that a pressure test after installation actually be performed. Most pipeline operators made this same interpretation until such time as testing became a clearly stated requirement in the 1955 edition.[22]

b. 1942 ASA B31.1, Section 2 Gas and Air Piping

The 1942 edition slightly revised testing requirements post-installation, as described in §223. Every piping system was required to be "capable of withstanding a test pressure" of 150% of the service pressure for Division 1 piping or 50 psig greater than the maximum service

[22] Hough, 1955.

pressure for Division 2 piping. A test after installation test “may be made with air or gas” which “need not exceed 120% of the maximum allowable working pressure” for Division 1 piping or “shall not exceed 120% of the maximum allowable working pressure” for Division 2 piping. As with the 1935 edition, §223 was interpretable as requiring that a piping system be specified to be strong enough to withstand a test without actually being required to undergo such a test. Working pressure for Division 2 piping were then established similarly to the 1935 standard, meaning it was based on the mill test or an engineering calculation if there was no mill test.

The duration of the pressure test, if performed, was not specified. §630(b) stated that “where an actual internal pressure test is made” (implying that an “actual internal pressure test” might not be made), the test pressure be maintained for long enough to inspect the joints and connections. This implies that where a test was made, its primary purpose was a leak test of flanged, threaded, or welded connections.

c. 1947 Addendum and 1951 B31.1, Section 2 Gas and Air Piping

The 1947 Addendum to the 1942 B31.1 standard did not change the testing requirements for gas and air piping. The 1951 B31.1 standard slightly revised the wording in §223 concerning post-installation testing to read “Where an internal fluid pressure test is made, it shall not exceed” 150% of the maximum allowable working pressure for Division 1 piping, and for Division 2 piping, 120% of or 50 psig greater than the maximum allowable working pressure whichever was greater. The language still only required a capability for withstanding a test, not the performance of an actual test. If a test was performed using any fluid (liquid or gaseous) the maximum test level was limited, and no minimum test duration was prescribed other than that it be long enough to inspect joints and connections for leaks.

d. 1952 B31.1, Section 8

Pressure testing requirements were found in Chapter 5, "Requirements after installation." §824 gave pressure testing requirements. These were identical to those found in §223 of the 1951 standard. The terms "Division 1" and "Division 2" designations were replaced with description of the systems in §807(c)(2)(a) and 807(c)(1)(a), respectively.

e. 1955 B31.1.8

The 1955 standard introduced the concept of 4 location class factors based on density of land development adjacent to the pipeline, each with different maximum allowable operating stress levels, and different pressure test requirements following installation. The precise definitions of the classes in terms of house counts and the dimensions of the reference area were somewhat different than today but the intended meanings of the classes were the same as today (e.g. Class 1 being rural, and so on) and the allowed operating stresses were also the same.

Testing requirements were stated in §841.3 "Testing after construction". §841.31 stated that all mains and services were to be tested, except tie-ins where individual test sections were eventually joined after testing. This was the first time in the gas piping standard that testing after installation became a firm requirement, but no minimum test duration was specified. The design requirement for the capability to withstand a pressure test was moved to Chapter 3 "Piping System Components and Fabrication Requirements", §831 "Piping System Components," where components were to be designed to withstand the system pressure test without failure, leakage, or impairment of their serviceability.

Pressure test requirements were given in §841.4 "Test requirements." §841.411 stated that all pipelines and mains to be operated at a hoop stress of 30% or more of the specified minimum yield strength (SMYS) "shall be given a field test to prove strength after construction and before being placed in operation." Under §841.412, piping installed in Class 1 areas was to be tested with air or gas to 1.1 times the maximum operating pressure or hydrostatically tested to at least 1.1 times the maximum operating pressure; piping installed in Class 2 areas was to be tested with air to 1.25 times the maximum operating pressure or hydrostatically tested to at least 1.25 times the maximum operating pressure; and piping installed in Class 3 and 4 areas was to be hydrostatically tested to at least 1.4 times the maximum operating pressure.

§841.413 waived the §841.412 hydrotest requirement for Class 3 and 4 piping if the ground temperature at the time of the test was or might fall below 32 F, or water of satisfactory quality was not available in sufficient quantity. In that case, an air test to 1.1 times the maximum operating pressure could be performed and the test pressure ratio of 1.4 did not apply.

§841.416 also allowed air testing of Class 3 and 4 pipe in any case, provided certain hoop stress limits were observed, the pipe was not operated at more than 80% of the test pressure, and the pipe had a seam joint efficiency factor of 1.00.

§841.5 "Safety during tests" advised the user to give due regard to the safety of employees and the public during pressure tests. When air or gas is the test medium, steps were required to remove persons not involved in conducting the test when the test hoop stress level exceeds 50% SMYS.

f. 1958 through 1982 B31.8

Pressure test requirements in the 1958, 1963, 1967, 1968, 1975, and 1982 standards and their addenda were the same as in the 1955 standard.

g. 1984 Addenda through 1986 B31.8

The 1984 Addenda to the 1982 edition revised the wording in §841.321 to specify that the pressure test of all piping intended to operate at hoop stress levels of 30% SMYS or greater be held for a minimum duration of 2 hours. This was the first occurrence of a specified minimum test duration in the B31.8 piping standard. Test levels were the same as previously. The pressure test requirements in the 1986 edition were the same as the 1984 Addenda.

h. 1989 through 2007 B31.8

The 1989 standard introduced a new operating stress level in excess of the traditional maximum operating stress level of 72% SMYS in Class 1, up to a maximum operating stress of 80% SMYS. Pipe in this category was referred to as Class 1, Division 1, and was to be pressure tested to a minimum stress level of 100% SMYS, with water as the only permitted test fluid. The traditional maximum operating stress of 72% SMYS was referred to as Class 1, Division 2. The same test requirements applied for Class 1, Division 2, and for Classes 2, 3, and 4 as in previous editions. The requirements from the 1989 edition remained unchanged in the 1992, 1995, 1999, 2003, and 2007 editions.

i. 2010 B31.8

Important revisions were made to the pressure testing requirements in the 2010 edition of the standard. The minimum test ratio for Class 1, Division 2 pipe (with a maximum operating stress level up to 72% SMYS) was raised to 1.25, regardless of test medium, and the minimum test ratio for Class 3 and 4 piping was raised to 1.50. Also, significant additional guidance on test planning, execution, and risk mitigation is provided in §841.3.1 “General requirements.”

2. CPUC General Order 112 and Sequels

The CPUC introduced regulations governing the design, construction, operation, and maintenance of natural gas pipelines within the State of California under General Order (GO) 112, first issued in 1961. The pressure testing requirements in GO 112 are discussed below.

a. 1961 GO 112

CPUC General Order 112 incorporated significant portions of the 1958 B31.8 standard. Certain changes were made to the pressure testing requirements. Among those changes were: the pressure testing requirements were extended to pipe operating at hoop stresses of 20% SMYS or more (rather than 30% SMYS), the test margin for Class 1 pipelines was increased to 1.25, the test margins for Class 3 and 4 pipelines was increased to 1.5, and the test pressure was required to be maintained until it was stabilized and for a period of not less than 1 hour. This last item appears to be the first reference to a minimum hold period.

b. 1964 GO 112-A

The 1964 GO 112-A incorporated content from the 1963 edition of B31.8. That standard did not change from prior years with respect to pressure testing. GO 112-A provided the same additional requirements on pressure testing as the 1961 GO 112.

c. 1967 GO 112-B

The 1967 GO 112-B incorporated content from the 1967 edition of B31.8. That standard did not change from prior years with respect to pressure testing. GO 112-B provided the same additional requirements on pressure testing as the 1961 and 1964 GOs.

d. 1971 GO 112-C

With the promulgation of 49 CFR Part 192, GO 112-C replaced content from B31.8 with content from Part 192 issued in 1970, with some additional requirements. The content from Part 192, Subpart J – Test Requirements, was incorporated verbatim and without additions or modifications.

e. 1979 GO 112-D

The 1979 GO 112-D incorporated the content from Part 192 issued in 1978. Since Subpart J remained relatively static in subsequent years, few changes in actual requirements occurred subsequently.

3. 49 CFR Part 192

The first full set of Federal pipeline regulations were issued in 1970. Subpart J – Test Requirements, §192.501 through §192.517 set forth requirements for pressure testing of pipelines after construction. An important new requirement relative to those contained in preceding or contemporaneous editions of B31.8 or GO 112 was §192.505(c) stipulating maintaining the strength test pressure for at least 8 hours. As originally proposed, the specified minimum test duration was 24 consecutive hours, a practice which was observed by a few but not all pipeline operators. This was reduced to 8 hours on the recommendation of the TPSSC.[23]

Aside from limitations based on maximum hoop stress levels, maximum operating pressure based on dividing the pressure test by a minimum specified factor, given in Subpart L – Operations, Clause 192.619(a)(2)(ii). For pipe installed after November 11, 1970, test pressure ratios were 1.1, 1.25, and 1.5 in Classes 1, 2, and 3 or 4, respectively. These were the same as in the 1961 GO 112. For pipe installed and tested prior to November 12, 1970, the test ratio for Classes 3 and 4 was 1.4, based on the requirements in the interim Federal standard between 1968 and 1970 which were the same as B31.8, and based on B31.8 being the de facto national standard prior to 1968 (except in California).

These requirements for testing after construction have remained relatively static in subsequent years.

[23] Fed. Reg., pg. 13255.

C. History of Recordkeeping Requirements

1. Recordkeeping Requirements Prior to 1955

Recordkeeping requirements specified in engineering standards for gas pipeline standards prior to 1955 were few and focused on welding. The 1935 B31 standard §526(b) required employers of welders to maintain records of welding operators they employed, showing dates of employment, results of their welding tests, and the identifying mark assigned to them. (Welders were required by §523(l) to stamp their identifying mark adjacent to welds they made on pipe.) The 1942 B31 standard, Appendix I, Part I, §10 required that records of welding procedure qualification testing be kept by the manufacturer or contractor. §22 therein required that copies of the record for each qualified welder be kept by the manufacturer or contractor. No retention period for these records was specified, and no other recordkeeping requirements were expressed.

No provisions or requirements for recordkeeping of any kind were specified in the 1951 B31.1, Section 2 or supporting sections of the standard dealing with welding or installation such as Section 6 "Fabrication Details." Similarly, none were given in the 1952 B31.1, Section 8 in its entirety.

It would be reasonable to expect that a variety of documents related to the design and construction of a pipeline facility be retained long-term, and perhaps this is necessary for accounting purposes for a regulated utility in accordance with State rules and regulations. However, retention of technical documents was not addressed by the engineering standards of the day.

2. Recordkeeping Requirements 1955 to 1961

a. 1955 B31.1.8

§824.25, in Chapter II "Welding," required that records of welding procedure qualification tests be retained for as long as the welding procedure is in use. Further, the pipeline operator or contractor (presumably whoever employed the welders) was required, during construction, to maintain a record of the welders qualified, their dates of employment, and test results.

In Chapter IV "Design, Installation, and Testing" §841.417 requires maintaining records showing the type of fluid used for pressure testing and the test pressure of pipelines that operate at a hoop stress of 30% or more of SMYS. The retention period is the useful life of the facility. This recordkeeping requirement is not stated under §841.42, §841.43, or §841.44 giving separate pressure test requirements for pipe operating at less than 30% SMYS but greater than 100 psig, leak test requirements for pipe operating at 100 psig or more, and leak test requirements for pipe operating at less than 100 psig, respectively. Thus an operator might reasonably not have retained records for tests performed in accordance with those paragraphs.

The 1955 edition was the first B31 standard to extend its scope beyond design, construction, and commissioning of the piping system to include operation and maintenance. Accordingly, additional recordkeeping language is introduced in Chapter V, "Operating and Maintenance Procedures." §850.3 "Basic requirement" states that each operating company having gas transmission or distribution facilities … shall: (a) Have a plan covering operating and maintenance procedures…(c) Keep records necessary to administer the plan properly." §851.4 states that records "should" be made of pipeline inspections for external or internal corrosion, listing several items of potential interest. §851.5 states that records "should" be made covering leaks and repairs. In addition, leakage survey records, line patrol records and other records relating to routine or unusual inspections "should" be kept on file as long as the section of line remains in service. §854.1 requires the operator to have plans for inspecting pipe-type and bottle-type gas holders; per §854.2 the operator "shall" keep records which detail the inspection and test work done and the results.

The terms "shall" and "should" were used throughout B31.1.8 and its sequels. "Shall" is understood to mean an action is required, while "should" is understood to mean an action is recommended but not required. Thus any action identified by "should" is reduced to guidance distinct from a strict requirement. However, since the B31 code was a voluntary standard and not a regulation, operators could choose not to follow requirements in the standard. Records adequate to effectively execute the pipeline operation and maintenance were required, but specific records were merely recommended and what was actually required was left to the operator. The possibility was not precluded that data different than or in addition to what the standard said "should" be recorded might be necessary in order to fulfill §850.3(c).

b. 1958 B31.8

Recordkeeping requirements and suggestions in the 1958 edition of B31.8 appear to be the same as those in the 1955 edition.

3. Recordkeeping Requirements 1961 to 1970

a. ASME B31.8

The 1963 and 1967 editions of B31.8 did not differ from the 1958 edition with respect to recordkeeping. The 1968 edition included certain enhancements such as the weld inspection requirements similar to those introduced by the 1961 GO 112 but without the accompanying weld inspection recordkeeping requirement. On the other hand, the corrosion inspection and leak investigation record keeping in §851.4 and §851.5 became required, not recommended.

b. GO 112

General Order 112 of 1961 incorporated most if not all of the 1958 B31.8 standard, with added requirements to better meet the objectives of the CPUC, for clarification, and for enforcement. Some important additions involved recordkeeping. GO 112 §206.1 added minimum inspections based on location class to B31.8 §828.2, and stipulated that a record be made of the results of the tests and the inspection method used. §209.1 extended the requirements from the 1958 B31.8 §841.3 and §841.4 for pressure testing of pipe that operates at 30% SMYS to pipe operating at 20% SMYS. This change in scope included the pressure test recordkeeping requirements in §841.417. In Chapter V, recommended patrols and corrosion inspections were made mandatory, and recommended records of corrosion inspections and leak investigations in §851.4 and §851.5 became required in GO 112 §202.1.

A Chapter VI "Records" was added consisting entirely of CPUC-added language. §301.1 stated that "the responsibility for maintenance of necessary records to establish that compliance with these rules has been accomplished rests with the utility. Such records shall be available for inspection at all times by the Commission…." In other words, the utility must maintain sufficient records to be able to prove on demand that the utility is complying with all of the rules. This could include design calculations, material procurement records, and a broad range of construction and installation inspection data, in addition to the operation and maintenance activities described above, and could well have required more recordkeeping than was the case before GO 112. Also, §302.1 required that specifications for materials and equipment, installation, testing, and fabrication be maintained by the utility.

A Chapter VII "Reports" was also added which required reporting to CPUC 30 days in advance of any proposed new installation, major reconstruction, or change in MAOP. Specific information to be reported to CPUC included the purpose or reason for the activity, specifications concerning pipe to be installed, the MAOP, and the test parameters to be used. Such reporting would likely tie in with additional recordkeeping activity both before and after the filing.

GO 112-A of 1964 incorporated most if not all of the 1963 B31.8. Since the 1963 B31.8 was not different from the 1958 edition with respect to recordkeeping, GO 112-A imposed similar additional requirements as GO 112 from 1961. GO 112-B incorporated most if not all of the 1967 B31.8. Since the 1967 B31.8 was not different from the 1963 edition with respect to recordkeeping, GO 112-B imposed similar additional requirements as GO 112-A from 1963

4. Recordkeeping Requirements post-1970

a. 49 CFR 192

Complete Federal safety standards for gas pipelines were introduced in 1970. Although some technical content was based on the 1968 edition of B31.8, the provisions went well beyond B31.8 in terms of inspections and recordkeeping. All provisions were required, not merely recommended ("shall" not "should"). Moreover, many of these requirements exceeded those in effect in GO 112 at that time. These are briefly discussed below.

- Subpart E – Welding: §192.243(f), where nondestructive testing (i.e. radiography) of welds is performed, a record is required showing the number of girth welds made, the number tested, the number rejected, and their disposition by location (e.g. milepost), for the life of the pipeline. Also §192.225(c), requires a record of the details of each qualification of a welding procedure, to be retained for as long as the procedure is used.
- Subpart J – Test Requirements: §192.517, a record is required of each test performed on pipelines operating above 30% SMYS or above 100 psig but below 30% SMYS. The record must indicate the following 7 items: the names of the operator, the responsible employee, and the test company (if any); the test medium used; the test pressure; the test

duration; pressure readings; elevation variations if they are significant; and leaks or failures. Such records must be retained for the useful life of the facility.

- Subpart K – Uprating: §192.553(b), a record is required of each investigation required to complete the uprate (e.g. review the design, and operating and maintenance history), work done, and each pressure test in connection with the uprate. The record must be retained for the life of the uprated segment.
- Subpart L – Operations: §192.619(a) sets forth criteria for establishing the MAOP, as the lowest of the design pressure of the weakest components or pipe based on specified attributes, the pressure obtained by dividing the post-construction test pressure by a specified factor, the highest actual operating pressure during 5 years preceding July 1, 1970, for furnace butt-welded pipe a pressure equal to 60% of the mill test pressure, for other pipe a pressure equal to 85% of the highest test pressure the pipe experienced in the field or pipe mill, or the maximum safe pressure determined in consideration of the condition and operating history of the pipeline.
- Subpart M – Maintenance: §192.709, a record is required of each leak discovered, repair made, line break, leak survey, line patrol, and inspection of transmission pipelines for as long as the line remains in service. Records would have to be retained at least until the next round of inspections (e.g. 5 years).
- Numerous other activities (sampling of odorant, valve maintenance, vault maintenance, distribution leakage surveys, and others) must occur at specified periodic intervals. While no recordkeeping was specified in connection with those activities, an operator would have to keep records of those activities to demonstrate compliance to the requirements.

The 1971 issuance of Part 192 added Subpart I on corrosion control, which required installation and criteria for the cathodic protection (CP) of buried steel pipelines, periodic monitoring of the effectiveness of the CP system, monitoring of internal corrosion, and monitoring of atmospheric corrosion. Recordkeeping requirements as of July 31, 1972 are discussed below.

- Subpart I – Corrosion Control: §192.491(a), each operator was required to maintain records or maps showing the location of cathodically protected pipe, CP facilities (e.g. rectifiers or anodes), and other structures bonded to the pipe. Also §192.491(b), each record or map from (a) plus records of each test or inspection of the CP system in sufficient detail to show adequacy of corrosion control were required to be retained as long as the facility is in service.

Important and extensive new recordkeeping requirements were put in place to support operator qualification (OQ) in 1999, integrity management planning (IMP) for transmission pipelines in high consequence areas (HCAs) in 2004, and distribution system IMP in 2009, as discussed below.

- Subpart N – Qualification of Pipeline Personnel: §192.807, requires the operator to maintain qualifications of personnel performing covered tasks. The qualification records must include identification of the individuals, the covered tasks each individual is qualified for, the dates of qualification, and the qualification method. The records must be maintained while the person is performing the covered task and for 5 years after.
- Subpart O – Gas Transmission Pipeline Integrity Management: §192.947, requires the operator to maintain records demonstrating compliance to Subpart O. The required items listed are (a) a written integrity management plan, (b) documents supporting the threat identification and risk assessment, (c) a written baseline assessment plan (BAP), (d) documents supporting each decision, analysis or process of each element of the BAP and IMP, (e) personnel training program and records, (f) prioritized assessment mitigation schedule, (g) documents supporting the Direct Assessment (DA) plan, (h) documents supporting the Confirmatory Direct Assessment (CDA) plan, and (i) verification of notifications made to OPS or any State regulator as required by Subpart O.
- Subpart P – Distribution Pipeline Integrity Management: §192.1011, requires the operator to maintain records that demonstrate compliance to the requirements of Subpart P, for at least 10 years. The records must include any superseded copies of the IMP.

b. GO 112-C

General Order 112-C issued in 1971 consisted substantially of the 1970 issuance of Part 192 with some modifications to meet the objectives of the CPUC. Part I – General Requirements, Subpart B – Records, §121.1 gives the same statement that maintaining records being the responsibility of the utility as Chapter VIII, §301.1 of GO 112-B. Similarly, §122.1 provides the same requirement to maintain specifications for material and equipment, installation, testing, and fabrication. Otherwise GO 112-C did not add recordkeeping requirements over and above those of Part 192.

c. **ASME B31.8**

The Federal safety standards effectively supplanted B31.8 as a governing standard nationally and in the State of California. However it continued to evolve as a technical standard with national and international application. Except where it conflicted with the provisions of Part 192, B31.8 could be used as technical guidance for achieving the performance based requirements of Part 192 (e.g. how to design a fabricated branch connection, how to evaluate the strength of corroded pipe, how to select a suitable repair). However, the recordkeeping requirements in B31.8 would likely not govern for a pipeline in California or elsewhere in the US.

D. Grandfathered Pipelines

1. Origin of the Term

The term “grandfathered pipelines” refers to those pipelines for which the operating pressure was established on the basis of operating history rather than pressure testing in accordance with Subpart L. The origin and basis is described in the Preamble to the first full issuance of Title 49 – Transportation published in the Federal Register.[24]

In the original proposal for Part 192, no recognition was given for piping installed prior to 1955[25] on the basis of very loose testing requirements, and for piping already operating at hoop stress levels greater than 72% SMYS. The Federal Power Commission (FPC) wrote a letter to OPS pointing out that there were thousands of miles of pipeline already in service, installed in accordance with prevailing standards and practices, that could not continue operating at their then-current levels and comply with the proposed regulations. The FPC also stated that based on

[24] Fed. Reg., pg. 13248-13276.

[25] In its comments to the original docket, the TPSSC referred to 1952 as the first year that the ASME B31.1.8 gave minimum test pressures. However, that new test requirement occurred in 1955, not 1952. The TPSSC comments are interpreted accordingly herein.

a review of the operating records of interstate pipelines, no improvement in safety would be gained by reducing the operating pressures of existing pipelines "which have been proven to be capable of withstanding present operating pressures through actual operation." In response, OPS included a "grandfather" clause to permit continued operation of pipelines at the highest operating pressure the pipeline had experienced in service during the 5 years preceding July 1, 1970 (even if the pipe had previously been subjected to a hydrostatic pressure test to qualify a higher MAOP but the pipe had not operated at that level during the specified 5-year interval).

It is noted that GO 112 already had set a regulatory precedent for the grandfathering of untested pipelines. Gas pipelines placed in service after July 1, 1961 were required to be pressure tested, but those installed before this date were exempted from pressure test requirements.[26] The CPUC was likely guided by provisions in §804.6 of the 1955 B31.1.8 and it's sequels that the standard was not intended to be applied retroactively to existing facilities insofar as design, installation, establishing the operating pressure, and testing were concerned. Consistent with these exemptions, the concept that new or evolving requirements concerning materials, design, construction, and the establishment of the MAOP are not retroactive to existing facilities that are already in operation was recognized in the Federal pipeline regulations from the outset. This concept is embodied in §192.13 and is fully expressed in the discussion of the retroactive effect on existing pipelines in the Preamble to Part 192.[27] §192.13 was incorporated in the 1970 GO 112-C.

[26] CPUC, Rulemaking 11-02-019, Findings of Fact No. 5, pg. 27.
[27] Fed. Reg., pg. 13248-13276, on the subject of the retroactive effect on existing pipelines, quotes the Natural Gas Pipeline Safety Act, Section 3(b): "Not later than 24 months after the enactment of this Act, and from time to time thereafter, the Secretary shall, by order, establish minimum Federal safety standards for the transportation of gas and pipeline facilities. Such standards may apply to the design, installation, inspection, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. Standards affecting the design, installation, construction, initial inspection and initial testing shall not be applicable to pipeline facilities in existence on the date such standards are adopted."

2. Unbroken Chain of Documentation Not the Rule

The practical significance of this was that it was not necessary for an existing pipeline already in service to have been pressure test to the minimum specified ratio of the MAOP. In fact, §192.619 offered four possible alternatives for establishing the MAOP that would not necessarily have required any documentation of a prior post-installation pressure test or, in some cases, other technical data about the pipe:

- §192.619(a)(1) recognized the design pressure of the weakest component in accordance with Subparts C and D. In this case the MAOP would be based on manufacturer's component pressure ratings or engineering calculations using specified material strength and wall thickness dimensions.
- §192.619(a)(3) recognized the highest pressure to which the pipeline had been subjected during the 5 years preceding July 1, 1970.
- §192.619(a)(4) recognized 85% of the highest test pressure to which the pipe had been subjected, either in the pipe mill or in the field. If no field test was documented, the mill test would govern. The operator could determine the pipe mill test pressure if he knew the pipe product specification and year of manufacture.
- §192.619(a)(5) allowed the operator to determine the maximum safe pressure considering the history of the segment, known corrosion, and actual operating pressure. This might be used, for example, with an uncoated pipeline that had experienced general wall thinning due to corrosion. (It is notable that this language existed prior to the use of in-line inspection for conducting integrity assessment, so an operator would likely not have complete information about the extent of corrosion.)

None of the above methods for establishing the MAOP necessarily require a documented prior hydrotest, meaning the regulator has since 1970 accepted that not all records need necessarily be present, or if present, need necessarily be complete or represent an unbroken chain of traceability. In fact, the method given in (a)(3) requires knowing no information about the specified grade or wall thickness of the pipe. These alternatives have been in Part 192 from 1970 to the present day. That these alternative methods of establishing MAOP were allowed proves that OPS recognized that records of testing or of pipe physical attributes were not always available. Note also that once the MAOP has been established using any one of the allowed methods, an operator is unlikely to ever revisit the issue except perhaps to address a change in class location or to uprate the pipe.

The likelihood of records going missing increases with the age of the system, particularly with systems built prior to 1970 when the more-extensive records requirements of Part 192 were in effect. Nationwide, 37% of natural gas transmission pipelines now in service were installed before 1960, and 61% were installed before 1970,[28] thus a sizable proportion of existing pipelines were installed at a time when only minimal provisions for recordkeeping were found in recognized standards and regulations.

In the course of my consulting activities with numerous pipeline operators, I have found that it is not at all uncommon for pipeline operators to have incomplete or inaccurate data about the attributes of portions of their pipeline systems, including specified pipe material grades, specified nominal wall dimensions, seam types, pipe manufacturers, coating types, pressure classes of valves, installation dates, construction specifications, welding procedures, pressure tests, corrosion control data, and operating pressure data. There are many reasons for loss of records including: perceived unimportance, change of facility ownership, fire or other loss event on site, or simple misplacement of paper documents. While the likelihood of gaps in the data increases with age, particularly with systems built prior to 1970, many of those systems were not "grandfathered." I have encountered data gaps of this nature associated with systems built as recently as 1990.

That gaps could exist in an operator's records does not automatically mean the operator is imprudent or irresponsible (although I would concede that there are few good excuses for missing data for facilities built in recent times). Having established the MAOP by any recognized method, an operator is obliged to operate accordingly and conduct such inspections,

[28] http://www.phmsa.dot.gov/pipeline/library/data-stats.

surveillance, maintenance, and repairs as necessary to preserve the safety and reliability of the pipeline. Prudent operators do that all the time without necessarily referring to historical data or documents.

Certain elements of an integrity management plan (IMP) in accordance with Part 192, Subpart O and ASME B31.8S, notably the integrity threat identification and risk assessment tasks, are facilitated by having reasonably complete and accurate historical and technical data. ASME B31.8S recognizes that data important or useful to these tasks may be missing. §4.2.1 "Data Requirements: Prescriptive Integrity Management Programs" states that if listed data elements relevant to an integrity threat are not available, the integrity threat must be assumed to apply, while §4.4 "Data Collection, Review, and Analysis" states that unavailability of data cannot be used to justify excluding an integrity threat. §5.9 "Data Collection for Risk Assessment" advises that if significant data are not available, the risk model may need to be modified based on an analysis of the impact of the data being unavailable. With each integrity threat listed with the prescriptive IMP under Appendix A, the paragraph "Gathering, reviewing, and Integrating Data" states that where the operator is missing data, conservative assumptions shall be used with the risk assessment or the segment shall be prioritized higher. In Part 192, Subpart O, §192.917 requires the operator to perform integrity threat identification and risk assessment in accordance with B31.8S, Sections 4 and 5, respectively. These sections incorporate the provisions discussed above concerning how to compensate for unavailable data. By referencing these sections of B31.8S, the regulations clearly contemplate that data important to an IMP may be unavailable.

E. Traceable, Verifiable, and Complete" Represents New Requirements on Recordkeeping

It has been suggested that the criteria for document reliability, being "traceable, verifiable, and complete" do not represent new standards for the quality of natural gas pipeline records. While the attributes of "traceable, verifiable, and complete" are certainly desirable, and reasonably expected in modern times, they are not standardized thresholds for data quality for pipelines of all eras, and have no basis in regulation. They represent new documentary criteria.

The terminology "traceable, verifiable, and complete," as applied to documents related to the design, construction, or operation of a natural gas pipeline, originated with Safety Recommendation (SR) P-10-2 issued by the National Transportation Safety Board (NTDB) to Pacific Gas & Electric (PG&E), issued on January 3, 2011. The NTSB's recommendation that records "should" (as opposed to "shall" or "must") be traceable, verifiable, and complete was applied to "all as-built drawings, alignment sheets, and specifications, and all design, construction, inspection, testing, maintenance, and other related records…relating to pipeline system components, such as pipe segments, valves, fittings, and weld seams for Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing".[29] The NTSB did not extend the recommendation to all pipeline facilities in all locations, nor to all facilities anywhere that have in fact been pressure tested.

These particular words appeared nowhere in any issuances of the B31 standard, GO 112, or 49 CFR Part 192 prior to SR P-10-2. The recommendation is not of a regulatory origin. The words, as used in connection with gas pipelines, did not originate with the Federal pipeline

[29] NTSB.

regulatory agency, the CPUC, or any other state pipeline regulatory agency. In this context, they originated with the NTSB (though NTSB may have co-opted them from applications outside the pipeline industry). The NTSB is not a regulatory agency: it is an independent agency of the US Government that has no responsibility for writing regulation and no powers of regulatory enforcement. Based on accident investigations that it is authorized to perform, the Board offers opinions and recommendations which may or may not be correct[30] or influential.[31,32]

Shortly after issuance of SR P-10-2, PHMSA issued ADB-2011-01 advising operators that records they rely on for establishing the MAOP "must be reliable" and that the records "shall be traceable, verifiable, and complete."[33] Because the recommendations contained in SR P-10-2 did not originate with PHMSA, had no precedent in PHMSA regulations or pipeline industry standards, and almost certainly were not made in consultation with PHMSA,[34] PHMSA offered no guidance in ADB-2011-01 as to what would satisfy their newly issued requirements. It took PHMSA 16 months to come up with guidance to the industry as to how to interpret the terminology.[35] In the meantime, the industry attempted to guess what was necessary to meet these requirements by issuing white papers[36] and developing individual company processes that were hoped to meet the regulator's criteria. No guidance was found in the GPTC "Guide,"[37] a reference used industry-wide for guidance on how to interpret and comply with Part 192. The

[30] It is my opinion that some NTSB pipeline failure investigations were inadequate or produced incorrect conclusions or recommendations.
[31] The NTSB's reports are not admissible in court, 49 USC 1154(b): "No part of a report of the Board, related to an accident or an investigation of an accident, may be admitted into evidence or used in a civil action for damages resulting from a matter mentioned in the report;" although its investigators' factual reports are, 49 CFR 835.2.
[32] NTSB recommended that ASME B31.8 revise its design requirements to account for the potential for longitudinal seam fatigue as a result of a failure in a hazardous liquid pipeline. The B31.8 committee reviewed the issue and concluded that there was no technical justification for such a revision.
[33] PHMSA, ADB-2011-01.
[34] 49 USC 1131: "The Board shall provide for appropriate participation by other departments, agencies, or instrumentalities in the investigation. However, those departments, agencies, or instrumentalities may not participate in the decision of the Board about the probable cause of the accident."
[35] PHMSA, ADB-2012-06.
[36] AGA, "Industry Guidance on Records Review," Oct. 2011.
[37] GPTC.

fact that no guidance could be found in any common external publication is consistent with the position that "traceable, verifiable, and complete" represented new criteria.

According to ADB-2012-06, "traceable" records are tied to original documents. It should not be surprising that documents that predated 1955 or perhaps 1961 might not have been retained because there was no requirement to retain them. It is also possible, with the passage of time, for original documents to be accidentally destroyed (e.g. by fire or flood), disposed of (e.g., in the event that facilities changed ownership), or merely misplaced or misfiled (which makes the document as good as lost). In any of these or similar circumstances, it would then be impossible to meet the "traceable" test. While unfortunate, such occurrences are not that uncommon, as discussed earlier.

"Verifiable" records are those in which data is confirmed by other separate documentation. Nowhere in the historical or current regulatory language reviewed above does agreement between multiple data sources appear as a requirement.

"Complete" records are finalized by a signature or date. ADB-2012-06 gives the following example: "a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable." It is noted that this example lists two items that are not specified in §192.517, namely the specific segment of pipe, and temperatures. Thus PHMSA's own requirements for recordkeeping since 1970 actually do not meet the new test by their own criteria.

The language of SR P-10-2 is clearly made in reference to "grandfathered pipelines" that are now in Class 3 or 4 areas. As explained in Part D above, gaps in documentation could well occur in connection with many "grandfathered pipelines." Therefore, the notion that the criteria of SR P-10-2 represent thresholds of data reliability that have always been present in regulations is illogical and inconsistent with established fact.

CHAPTER 6

THE DECISION TREE AND

SUBPRIORITIZATION PROCESS;

TIMP PROGRAM;

MANAGING PIPELINE INTEGRITY;

AND PROPOSED CASE

TABLE OF CONTENTS

PREPARED REBUTTAL TESTIMONY

DOUGLAS SCHNEIDER

I. INTRODUCTION

My name is Douglas Schneider. I am the Director of Pipeline Integrity for Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E). I sponsored opening testimony in this proceeding and my qualifications can be found in that volume. This testimony responds to the prepared direct testimony of several intervening parties to Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company's (SDG&E) Proposed Natural Gas Pipeline Safety Enhancement Plan. Specifically, this testimony responds to claims made, primarily by the Division of Rate Payer Advocates (DRA) and The Utility Reform Network (TURN), that:

1. SoCalGas and SDG&E's Pipeline Safety Enhancement Plan is not consistent with the Commission's Decision (D.11-06-017).
2. Certain pipeline features should have been or should be managed as part of SoCalGas and SDG&E's Transmission Integrity Management Program (TIMP).
3. A prudent operator would have pressure tested and maintained records of those pressure tests well before regulations came into existence.
4. The Commission should reject SoCalGas and SDG&E's proposed case.

Intervenors fundamentally misunderstand what the Commission ordered natural gas operators to do in D.11-06-017. Specifically, Ordering Paragraph 4 requires that California natural gas transmission operators "file and serve a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) to comply with the requirement that all in-service natural gas transmission pipeline in California . . . [be] pressure tested in accordance with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c)."[1] As the Commission states, "Historic exemptions must come to an end with an orderly and cost-conscience [*sic*] implementation plan."[2]

SoCalGas and SDG&E's Pipeline Safety Enhancement Plan accomplishes the intent of the Decision to cost effectively end historic exemptions in a thoughtful and orderly manner. To do so, SoCalGas and SDG&E's decision tree proposes to test or replace all transmission pipelines that have not been pressure tested to current standards, with identified pipelines in populated areas receiving priority. DRA seems to miss the fact that SoCalGas and SDG&E's proposed decision tree already takes into account the location of the pipeline when DRA recommends the Commission require the location of pipelines be considered (or included) as part of the sub-prioritization process.

There is also no merit to DRA's recommendation to reduce PSEP costs by $74 million because certain pipelines should have been or should be managed as part of SoCalGas and SDG&E's Transmission Integrity Management Program (TIMP). In making this recommendation, DRA appears to misunderstand the relationship between existing regulations and what was ordered by the Commission in D.11-06-017. This misunderstanding bleeds over into DRA and TURN's conclusions that a prudent operator should have maintained pressure test records well before regulations came into existence. As explained in Section 2 below, D.11-06-017 sets forth new requirements that gas operators must now meet, and these requirements are incremental to existing regulations. Thus, the suggestion that SoCalGas and SDG&E are somehow imprudent as operators because they lack some historic records is unfounded.

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[1] D.11-06-017, p. 31.
[2] D.11-06-017, p. 18.

SoCalGas and SDG&E take seriously the obligation to maintain their transmission systems in a safe operating condition, and as a prudent operator, take into account when assessing the integrity of a pipeline what records exist for that pipeline.

DRA and TURN's recommendations that the Commission reject SoCalGas and SDG&E's proposed case are equally shortsighted. Section 5 explains how SoCalGas and SDG&E's proposals to include the replacement of wrinkle bends, girth welds and non-piggable, non-state-of-the-art pre-1946 transmission lines are intended to comply with the Commission's commitment to enhance the safety of natural gas transmission pipelines and the directive in D.11-06-017 to consider, among other things, the retrofitting of pipelines "to allow for in-line inspection tools." [3,4]

II. DRA FUNDAMENTALLY MISUNDERSTANDS WHAT THE COMMISSION ORDERED PIPELINE OPERATORS TO DO.

DRA claims in its testimony that SoCalGas and SDG&E have misinterpreted D.11-06-017. According to DRA's witness Ms. Phan:

> "SoCalGas and SDG&E estimate that an additional 2,000 miles of transmission segments will need to be addressed to determine whether they require pressure testing or replacement. Sempra assumes in its filing that, "the CPUC will require pressure testing or replacement of pipeline installed prior to 1970 since modern standards were not in place before that time." Sempra is interpreting D.11-06-017 to require all pipeline segments installed prior to 1970 to be tested in accord with 49 CFR 192.619, excluding subsection 192.619(c).
>
> D.11-06-017 states, "This decision orders all California natural gas transmission operators to develop and file for Commission consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plans) to achieve the goal or orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been

[3] D.11-06-017 – Ordering paragraph 8
[4] D.11-06-017 – p. 16 – Section 3

> pressure tested."[5] D.11-06-017 does not require the digging up and testing to Subpart J those pipeline segments that have been previously tested."[6]

DRA does not take into account Ordering Paragraph 4 in its analysis. That ordering paragraph expressly requires that "all in-service natural gas transmission pipeline in California . . . [be] pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c),"[7] and the Commission states on page 18 of its decision that "[h]istoric exemptions must come to an end."[8] These statements make plain that the Commission's goal is to have all transmission pipelines tested in accordance with 49 CFR 192 Subpart J (Subpart J). That is why SoCalGas and SDG&E's decision tree includes, as part of Phase 2, the testing or replacing of lines that do not meet Subpart J standards, or the "modern standard" as described by the Commission.

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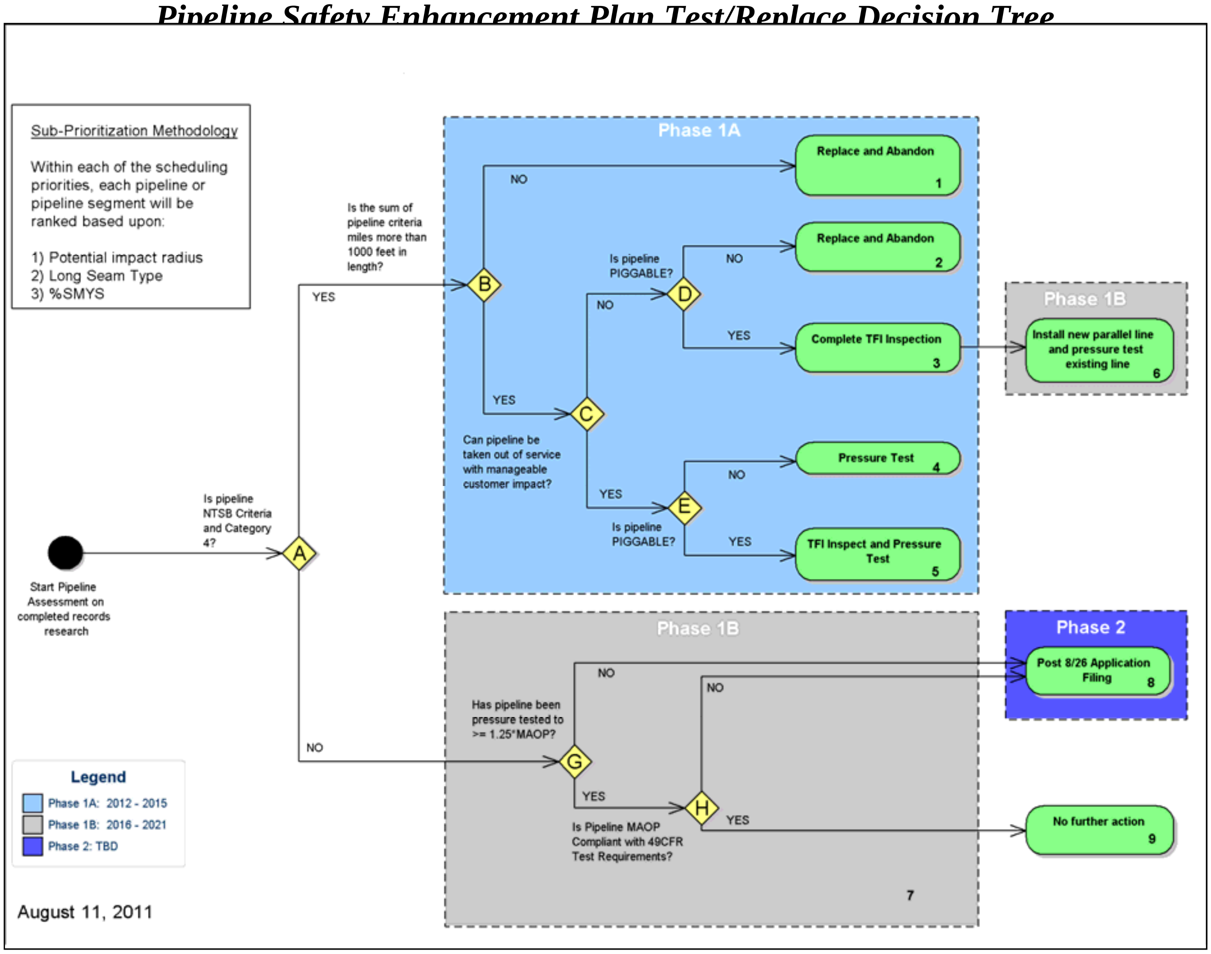
[5] D.11-06-017, p. 1 – Section 1 – Summary.
[6] DRA Exhibit 2 Prepared Testimony of D. Phan in A.11-11-002 SoCalGas and SDG&E PSEP, pp. 9-10.
[7] D.11-06-017, p. 31.
[8] D.11-06-017, p. 18.

Figure DMS-1

Pipeline Safety Enhancement Plan Test/Replace Decision Tree



As shown in the decision tree, all transmission pipelines are addressed within the tree, with Phase 1A addressing the pipeline segments in Class 3 and Class 4 locations and Class 1 and Class 2 High Consequence Areas that do not have sufficient documentation of a pressure-carrying capacity of 1.25 times the MAOP. Subsequent phases address the remaining transmission lines that are not tested to modern standards and are to be either tested or replaced.

As stated in opening testimony, SoCalGas and SDG&E propose to evaluate, as part of Phase 1, the use of transverse field inspection (TFI) tools as an equivalent means of assessing long seam stability for in-service pipelines. The proposed demonstration would include validation of TFI in parallel with pressure testing. If accepted, TFI could significantly reduce the costs of Phase 2. If no alternative to pressure testing is approved, SoCalGas and SDG&E, based on D.11-06-017, must pressure test or replace in Phase 2 all in-service transmission pipelines that were not tested to modern standards.

A. GO 112 As It Existed During The 1960's And Industry Standard Recommendations For Pressure Testing Do Not Meet Subpart J Standards

Modern pressure test standards are contained in Subpart J, which prescribes the minimum leak test and strength test requirements for pipelines. This standard is incorporated into today's General Order 112. Subpart J went into effect in 1970 and is recognized as the modern standard for pressure testing, as evidenced by the fact that the grandfather clause specified in 49 CFR 192.619(c) cannot be applied to pipelines that are installed after the effective date of Part 192 – Transportation of Natural and Other Gas By Pipeline: Minimum Federal Safety Standards.[9]

Subpart J specifies the maximum test pressures to prove strength by test medium (water, air, inert gas or natural gas), the test pressure that must be achieved, and the duration that test pressure must be held. For pipelines intended to operate at a hoop stress of 30% or more of its specified minimum yield strength (SMYS), the pressure test must be held for a minimum of 8 hours, unless the pipe is a fabricated unit or short segment where a post-installation test is impractical, in which case a pre-installation test of 4 hours is required. The test duration for pipelines intended to operate at or above 100 psig but less than 30% of SMYS is 1 hour.

Subpart J also specifies recordkeeping requirements. For pipelines with an MAOP at or above 100 psig, a gas operator must retain a record of: (1) the operator's name, the name of the employee responsible for the test, and the name of any testing company used; (2) test medium

[9] The basis for the grandfather clause comes from the Natural Gas Pipeline Safety Act (Section 3(b)), which states, *"Not later than 24 months after the enactment of this Act, and from time to time thereafter, the Secretary shall, by order, establish minimum Federal safety standards for the transportation of gas and pipeline facilities. Such standards may apply to the design, installation, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. Standards affecting the design, installation, construction, initial inspection and initial testing shall not be applicable to pipeline facilities in existence on the date such standards are adopted."*

used; (3) the test pressure achieved; (4) the duration of the test; (5) record of pressure readings; (6) significant elevation variations; and (7) the disposition of any leaks and failures during the test.

General Order 112 as it existed in the 1960's, in contrast, prescribed that a gas operator only retain a record that shows the type of fluid used for the test and the test pressure achieved for pipelines operating at a hoop stress of 20% or more of SMYS. While General Order 112 prescribed the permissible test fluids and minimum test pressures for pipelines to be operated at 100 psig and higher, it required a test duration of at least one hour only for pipelines intended to operate at a hoop stress of 20% or more of SMYS. There was no requirement that a record of the test duration be retained. As a result, pipelines tested under General Order 112 that operate at a hoop stress of 30% or more of SMYS may not have been tested for 8 hours as required in the modern standard, and it is highly unlikely that records exist that meet the recordkeeping requirements of Subpart J.

General Order 112 specifically provides, as stated in D.11-06-017 Findings of Fact 5, that pipelines installed before 1961 were exempted from any pressure test requirements. For pipelines that were pressure tested prior to 1961 but after 1955, they would have likely been tested per the 1955 edition of the American Society of Mechanical Engineers (ASME) B31.1.8 standard code for pressure piping – Gas Transmission and Distribution Piping Systems. That standard also does not meet Subpart J requirements. ASME B31.1.8 specified a post-construction strength test for pipelines that operate at a hoop stresses of 30% or more of SMYS; however, there was no minimum test duration specified and the test records that were required to be retained included only the test medium and the test pressure achieved. Prior to 1955, as discussed in Mr. Rosenfeld's testimony, there were no industry standards for post-construction pressure testing: “Up until the 1940’s, if proof testing was done at all, it was usually accomplished using the transported commodity . . . .”[10]

DRA falsely indicates that post-construction pressure testing was required in the period from 1935 to 1955, and mistakenly identifies the design requirements in Section 824 of the 1951 edition of B31.1.8 as testing requirements. Witness Michael J. Rosenfeld provides detailed discussion of the history and meaning of strength testing requirements in the natural gas pipeline industry. The following table summarizes the strength testing and associated record keeping requirements of industry standards and regulatory requirements.

[10] Testimony of Michael J. Rosenfeld, Section II.B at p. 6; *see also* Section II.B.1a. - II.B.1.d.

Figure DMS-2

Summary Table of Post Construction Pressure Tests and Duration

Post Construction Strength Test Duration and Record Specification				
	Industry Standard		Regulatory Requirement	
N/S = Not Specified N/A = Not Applicable	Pre-1955	1955 - 1961	GO 112 1961 - 1970	GO 112 Post 1970 (49 CFR 192)
Strength Test Requirement and Duration when Specified				
30% and more of SMYS	N/A	Yes - N/S	Yes - 1 Hour	Yes - 8 Hour
20% SMYS up to 30% SMYS	N/A	Yes - N/S	Yes - 1 Hour	Yes - 1 Hour
100 psig to 20% SMYS*	N/A	Yes - N/S	Yes - N/S	Yes - 1 Hour

Documentation Requirements - 30% and more of SMYS				
Operator Information	No	No	No	Yes
Test Medium	No	Yes	Yes	Yes
Test Pressure	No	Yes	Yes	Yes
Test Duration	No	No	No	Yes
Record of Pressure Readings	No	No	No	Yes
Significant Elevation Changes	No	No	No	Yes
Disposition of Leaks and Failures	No	No	No	Yes

Documentation Requirements - 20% SMYS to < 30% SMYS				
Operator Information	No	No	No	Yes
Test Medium	No	No	Yes	Yes
Test Pressure	No	No	Yes	Yes
Test Duration	No	No	No	Yes
Record of Pressure Readings	No	No	No	Yes
Significant Elevation Changes	No	No	No	Yes
Disposition of Leaks and Failures	No	No	No	Yes

Documentation Requirements - 100 psig to < 20% SMYS*				
Operator Information	No	No	No	Yes
Test Medium	No	No	No	Yes
Test Pressure	No	No	No	Yes
Test Duration	No	No	No	Yes
Record of Pressure Readings	No	No	No	Yes
Significant Elevation Changes	No	No	No	Yes
Disposition of Leaks and Failures	No	No	No	Yes

* Some editions of the code refer to pressures in excess of 100 psig, while others including current code, refer to at or above 100 psig.

B. Post San Bruno Identification Of Transmission Pipelines In Populated Areas That Had Not Previously Undergone A Testing Regimen

Contrary to what DRA and TURN suggest, a pipeline segment included in Phase 1A of SoCalGas and SDG&E's Pipeline Safety Enhancement Plan (PSEP) does not necessarily mean that pressure test records for that segment do not exist that would have met pre-1970 pressure testing recordkeeping requirements. SoCalGas and SDG&E conservatively classified pipelines in populated areas as Category 4 (pipelines where records of an adequate testing regimen to validate the safe operating pressure have not been located), and subsequently developed the PSEP to prioritize these segments for action in Phase 1A. As a result, some pre-1971 pipelines may satisfy the recordkeeping requirements in effect at the time of the commissioning pressure test, but lack recordkeeping detail now required to satisfactorily document the pressure test and allow for scheduling of their testing or replacement to a later phase in PSEP. SoCalGas and SDG&E explain in their opening testimony that pipelines prioritized in Phase 1A for replacement or pressure test were identified through the record review process described in the April 15, 2011 Report of Southern California Gas Company and San Diego Gas & Electric Company on Actions Taken in Response to NTSB Safety Recommendations. Those recommendations (NTSB Recommendations P-10-2, P-10-3 and P-10-4) instructed PG&E to:

1) Identify transmission pipelines in populated areas that had not had their MAOP established through pressure testing;
2) Determine the MAOP based upon strength calculations using traceable, verifiable and complete records; or

3) If unable to validate a safe operating pressure through a strength test or engineering calculation, test the pipeline or replace it.[11]

Following the NTSB's recommendations, Executive Director Paul Clanon notified SoCalGas and SDG&E of these urgent safety recommendations and directed us to report on those "steps [we] will take proactively to implement corrective actions as appropriate" for our natural gas transmission pipeline system.[12] In response to that directive, SoCalGas and SDG&E undertook an intensive records search to identify gas transmission lines that had not previously been pressure tested to a 1.25 times MAOP safety margin.[13] Each pipeline's records were reviewed to determine if sufficient documentation existed to demonstrate a post-construction test to that safety margin. Sufficient documentation meant that the records have supporting information. For example, when a note on a company form indicated that the test pressure and medium were sufficient to meet the record keeping requirements, SoCalGas and SDG&E used only those values if there was corroborating information of the test from other documentation.

SoCalGas and SDG&E chose not to use engineering calculations allowed in recommendation P-10-3 as a method to avoid pressure testing of a pipeline per recommendation P-10-4 for the reasons explained in the April 15, 2011 report.

> SoCalGas and SDG&E did not validate the MAOP of any pipeline segments using the approach specified in Safety Recommendation P-10-3. In order to do so, SoCalGas and SDG&E believe they would need to affirmatively state that no pipeline materials other than those specified and documented in identified records were installed. That is, records must demonstrate, without fail, that no components of any portion of the pipeline

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[11] January 3, 2011 NTSB Press Release, available at: http://www.ntsb.gov/pressrel/2011/110103html.

[12] January 3, 2011 letter from Paul Clanon, Executive Director of the Commission to Michael Allman, President and Chief Executive Officer, Southern California Gas Company, Jeffrey Shaw, Chief Executive Officer, Southwest Gas Corporation, and Jesse Knight, Jr., Chairman and Chief Executive Officer, San Diego Gas & Electric Company, available at http://www.cpuc.ca.gov/NR/rdonlyres/CE921E44-7596-4B04-B875-A0F521FF27A3/0/LettertoSoCalUtilities010311.PDF

[13] April 15th, 2011 Report of Southern California Gas Company and San Diego Gas & Electric Company on Actions Taken in Response to NTSB Safety Recommendations, p. 7.

segment were changed subsequent to the date of identified records, effectively requiring a perfect chain of document custody for pipelines that may have been installed over fifty years ago and that have been subject to many different document retention regulatory requirements.[14]

The following tables show the miles of Class 3 and 4, and Class 1 and 2 High Consequence Area transmission pipeline (criteria miles) identified as having sufficient documentation of a pressure test to 1.25 times the MAOP (category 1 and 2)[15],[16] and pipelines that do not have sufficient pressure capacity documentation of 1.25 times the MAOP (category 4). These are grouped by the time periods associated with pressure testing standards and General Order 112 prior to the implementation of the Federal code.

Figure DMS-3

Phase 1A Category 4 Criteria Miles by Pressure Test Time Period

Category 4 Phase 1A Mileage by Testing Time Period

Company	**Pre-1955**	**55 – 61[17]**	**62 – 70**	**Total**
SoCalGas	259	37	19	315
SDG&E	46	14	1	61
Total	**305**	**51**	**20**	**376**

[14] April 15th, 2011 Report of Southern California Gas Company and San Diego Gas & Electric Company on Actions Taken in Response to NTSB Safety Recommendations, p. 9.

[15] Category 1 are pipelines with documentation of a hydrostatic pressure test to 1.25 times or more of the MAOP, Category 2 are pipelines with documentation of a pressure test using a medium other than water to 1.25 times or more of the MAOP.

[16] SoCalGas and SDG&E also have in their April 15, 2011 Report a "Category 3." Category 3 included pipelines that had documentation sufficient to show that it had operated continuously at a pressure of at least 1.25 times greater than its current MAOP (i.e., an equivalent in-service gas pressure test). The Commission's June Decision does not allow for an in-service gas pressure test. Accordingly, for purposes of our PSEP filing, our Category 3 pipelines are included in a later Phase.

[17] Code specified testing for pipeline operating at a hoop stress greater than 30% SMYS. 18 of the 37 miles at SoCalGas and 2 of the 14 miles at SDG&E operate with an MAOP less than 30% SMYS.

Category 1 and 2 Criteria Miles with 1.25 times MAOP or Greater Pressure Test by Time Period

Category 1 & 2 Criteria Mileage by Testing Time Period

Company	Pre-1955	55 – 61[18]	62 – 70	Total
SoCalGas	147	286	182	615
SDG&E	11	55	12	78
Total	**154**	**341**	**194**	**689**

C. DRA's Proposed Modifications To The Sub-Prioritization Process Fails To Recognize That The Existing Process Is Already Based Upon Pipeline Location

DRA claims that SoCalGas and SDG&E's "sub-prioritization methodology does not account for pipeline location, risk assessments from TIMP, or maintenance data in ranking pipeline for MAOP validation."[19] They inappropriately recommend that these elements be included in PSEP.[20] This recommendation ignores that SoCalGas and SDG&E account for pipeline location in the decision tree, as shown on page 4. Also, DRA's recommendation that the sub-prioritization process incorporate TIMP and maintenance data would dilute focus away from higher priority long seams.

Pipeline location is used in the first step of SoCalGas and SDG&E's decision tree. Decision tree node A determines whether the pipeline is "NTSB Criteria and Category 4." "NTSB Criteria," as described in SoCalGas and SDG&E's opening testimony, includes pipelines

[18] Code specified testing for pipeline operating at a hoop stress greater than 30% SMYS. 67 of the 286 miles at SoCalGas and 1 of the 55 miles at SDG&E operate with an MAOP less than 30% SMYS.
[19] Exhibit DRA-1 Executive Summary and Cost Recovery Policy in R.11-11-002, p. 3.
[20] DRA Exhibit 2 Prepared Testimony of D. Phan in A.11-11-002 SoCalGas and SDG&E PSEP, p. 83. (" . . . Sempra should consider ranking pipeline segments in descending order of class location from Class 3 to Class 1, decreasing PIR's and percentage of High Consequence Area (HCA) pipe within each project. Sempra should consider the date of the last assessment in sub-prioritization as well. All other factors being equal, a pipeline that is more problematic or shows a higher level of risks, based on the TIMP risk assessments, should be given higher priority than a pipeline that was assessed and was ranked with a lower level of risks.").

in Location Class 3 and 4 and additionally Class 1 and 2 High Consequence Areas (i.e., more populated areas).[21] After this initial prioritization, the sub-prioritization criteria is applied to pipelines in populated areas that do not have sufficient documentation of the pressure-carrying capacity. As an additional consideration regarding the use of pipeline location for ranking purposes, it should be noted a pipeline is not necessarily remote or without the influence of human factors simply because it is a Class 1 or 2 location. While this may be generally true, many pipelines in Class 1 and 2 locations are near population centers and areas of human influence where a pipeline failure would not be acceptable.

The primary objective of the SoCalGas and SDG&E proposed sub-prioritization process is to rank pipelines with a higher potential risk for rupture in populated areas ahead of pipelines with a lower risk for rupture in populated areas. Pipeline failures are generally categorized in terms of leak versus rupture, where rupture represents larger and more hazardous pipeline failures similar to the pipeline rupture in San Bruno. Rupture risk is dominated by stress level, which in turn is driven by the combination of factors including pressure, diameter, wall thickness, manufacturing process and material strength.

The SoCalGas and SDG&E proposed sub-ranking of pipelines by potential impact radius (PIR) serves as an effective proxy for the accounting of all factors contributing to stress level and, therefore, rupture risk. Potential impact radius correlates closely to stress level as the two factors share in common both diameter and pressure, and PIR proportionately reflects the increased exposure to rupture risk to people by accounting for the areas of impact as opposed to stress level alone (i.e., potential impact radius avoids the pitfalls of prioritizing a small but highly stressed pipeline with a small impact area over a medium or low stress pipeline with a much

[21] SoCalGas/SDG&E Amended Testimony, p. 49.

greater area of impact). In turn, division of the potential impact radius by the long seam factor serves to up-rank pipelines with longitudinal seam factors less than 1.0, and thus provide for the initiation of those projects sooner than if only the PIR were used. Stress level is directly proportional to increased rupture risk, and is used as the final prioritization factor to account for increased likelihood of pipe failure as opposed to the consequences of a failure.[22]

It is for these reasons that PIR, seam type, and stress level have the greatest effect on the pressure-carrying capacity of the long seam, and should remain as the main factors for ranking the testing or replacement of pipelines that are in populated areas and do not have sufficient demonstration of a 1.25 times MAOP safety margin.

DRA also recommends that TIMP and maintenance information be used as part of the prioritization criteria. As explained in greater detail below, TIMP, and by extension, general maintenance, are separate from PSEP. The priority of PSEP is to validate the integrity of long seams through pressure testing, addressing more heavily populated areas prior to lesser populated areas. DRA's recommendation to add corrosion control and other data into the prioritization process would result in a prioritization process that does not meet the objective of prioritizing pipelines with the greatest potential consequences from long seam failure above those with a lesser potential consequences.

[22] As an additional consideration, it should be noted a pipeline is not necessarily either remote or without the influence of human factors simply because it is Class 1 or 2 locations. While this notion may be generally true, many pipelines do exist in Class 1 and 2 locations that are very near population centers and areas of human influence where a pipeline rupture would not be acceptable.

III. WHAT THE COMMISSION HAS ASKED NATURAL GAS TRANSMISSION PIPELINE OPERATORS TO DO UNDER D.11-06-017 IS DIFFERENT FROM INTEGRITY ASSESSMENT WORK PERFORMED UNDER TIMP

Intervenors assert that the assessment work funded and completed under TIMP requirements are effectively redundant with PSEP requirements, and any overlap between the two programs should be discounted from recovery for PSEP work. In their testimony DRA states:

> The abandonment, replacement and hydrostatic testing of these 383 miles as part of the Plan will also enable Sempra to meet the TIMP requirements of reassessing these pipelines in the next seven years. The abandonment of 21 miles will remove these pipelines from the TIMP and Sempra will not need to assess these pipelines again. The replacement and hydrostatic testing of the remaining 362 miles will meet the assessment methods required by TIMP. Sempra requests funding for the assessments and reassessments of TIMP pipelines in its General Rate Case applications. In the most recent GRC filed in December 2010, Sempra requested $25 million each year, starting in 2012, for the assessment and reassessment of pipelines as part of the TIMP.
>
> Since Sempra is managing the assessment work of these specific lines under TIMP, DRA recommends an adjustment to the Plan cost estimates to reflect the accounting of these 383 miles in that program. If the Plan cost estimates for these 383 miles are not adjusted, then Sempra would receive funding for the assessment/management of the same pipelines twice, as part of the GRC and as part of the Plan.[23]

TURN and IP Watson also make similar points in their testimonies.[24] DRA, TURN and IP Watson are wrong. The requirements to comply with D.11-06-017 are new and incremental to the work to be done under TIMP. The scope of affected pipelines and the resultant activities required within each program scope differ.

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[23] DRA Exhibit 2 Prepared Testimony of D. Phan in A.11-11-002 SoCalGas and SDG&E PSEP, pp. 79-80.

[24] On page 19 of the Testimony of Thomas J. Long, Sempra Utilities' Pipeline Safety Enhancement Plan A.11-11-002, TURN provides the following statement: "With respect to the many segments in the PSEP with an identified manufacturing threat, the Sempra Utilities should be required to demonstrate that any testing that should have been conducted under Subpart O would not obviate the need to address the segment in the PSEP. Similarly, on page 14 of the Prepared Direct Testimony of R. Thomas Beach on Behalf of Southern California Indicated Producers and Watson Cogeneration Company A.11-11-002, IP Watson states: "The PSEP should be carefully scrutinized to ensure that it does not duplicate the 22 utilities' existing TIMP activities funded through their current rates."

TIMP applies to High Consequence Areas and nine threat categories. Phase 1A of PSEP goes beyond High Consequence Areas because it covers NTSB Criteria segments and is focused on threats that are considered stable under TIMP. On page 49 of our opening testimony, we describe the difference in mileage between TIMP and Phase 1A of our Pipeline Safety Enhancement Plan:

> The NTSB's criterion exceeds the miles of pipelines operated in High Consequence Areas by SoCalGas by 247 miles and the pipelines operated by SDG&E in High Consequence Areas by 37 miles. In other words, the NTSB directives apply to 284 miles of transmission Pipelines operated by SoCalGas and SDG&E that are not part of our existing Transmission Pipeline Integrity Management Programs, and exceed those requirements by about 21%.[25]

SoCalGas and SDG&E identify High Consequence Areas in accordance with Subpart O - Gas Transmission Pipeline Integrity Management, 49 CFR 192.903 (Subpart O). Subpart O provides two options for defining High Consequence Areas, and SoCalGas and SDG&E utilize the option known as "Method 2." Using Method 2 results in some location Class 3 pipelines not being located in a High Consequence Area.

SoCalGas and SDG&E's Phase 1A plan was designed to comply with the Commission's directive to "start with pipeline segments in Class 3 and Class 4 locations and Class 1 and Class 2 High Consequence Areas, with pipeline segments in other locations given lower priority for pressure testing." This is the same scope as that covered by the NTSB in its January 3rd recommendations to PG&E. Thus, Phase 1A covers all Class 3 locations whether they are defined by "Method 2" as a High Consequence Area. Also included in Phase 1A are some accelerated miles, as explained in opening testimony and in the rebuttal testimony of Richard D. Phillips.

[25] SoCalGas/SDG&E Amended Testimony, p. 49.

The second primary difference between TIMP and the Pipeline Safety Enhancement Plan are the contrasting activities required within each program scope. TIMP is designed to be a broad threat identification process. Under TIMP, each pipeline within a High Consequence Area is evaluated individually, and an approach is selected to complete the required assessment. This evaluation includes the identification of pipeline threats within nine categories defined by ASME Standard "Managing System Integrity of Gas Pipelines," B31.8S-2010, and as described in the following excerpt from our Testimony:

> Under current Federal regulations, potential threats to the safe operation of a pipeline are categorized by nine potential failure modes. The nine potential failure modes are grouped by three time factors: (1) Time Dependent; (2) Time Independent; and (3) Stable. Time Dependent threats are generally those related to corrosion and include external corrosion, internal corrosion and stress corrosion cracking. Time Independent threats include third party/mechanical damage, incorrect operational procedure, and weather-related and outside force. Stable threats are manufacturing-related, welding/fabrication-related or equipment-related.[26]

The threat identification described above determines the appropriate assessment method to be used for each individual pipeline covered under TIMP. While these assessment methods include pressure testing, they also include in-line inspection (ILI), direct assessment, and "other technologies." While equivalent per the code, each method has advantages and disadvantages when compared to each other.

Manufacturing and construction defect stability under TIMP is reliant upon operating pressure history and pressure test history (inclusive of the grandfather clause under 49 CFR 192.619(c)) as noted in the NTSB San Bruno investigation:

[26] SoCalGas/SDG&E Amended Testimony, p. 39.

> In summary, under 49 CFR 192.917(e)(3), operators are entitled to consider known manufacturing- and construction-related defects to be stable, even if a line has not been pressure tested to at least 1.25 times its MAOP.[27]

As a result, under normal operating circumstances, defects under TIMP can be considered stable even in the absence of a post-construction pressure test to 1.25 times MAOP:

> An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the High Consequence Area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.
>
> (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;
>
> (ii) MAOP increases; or
>
> (iii) The stresses leading to cyclic fatigue increase.[28]

This is in stark contrast to the requirements of the Commission's June 2011 Decision. While the Decision focuses on one of the nine threats identified under TIMP, that is manufacturing threats, the Decision is quite prescriptive on what must be done to address that threat – any pipeline that is in service that has not been pressure tested to Subpart J standards <u>must</u> be pressure tested or replaced. While pressure testing is appropriate to assess the integrity of the long seam, it may not be the appropriate assessment method under TIMP to deal with the other threats to the pipeline. Pressure testing, for example, does not provide detailed information concerning the time dependent threat of corrosion compared to in-line inspection and direct assessment. Thus, for a reassessment, it would not provide the data needed to compare the reassessment to the data gathered during the baseline assessment, so that SoCalGas and SDG&E

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[27] Pipeline Accident Report, Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, National Transportation Safety Board, p. 113.
[28] CFR 49 Part 192 section 192.917(e)(3).

could take appropriate action if the data showed that corrosion is now occurring on the pipeline being reassessed.

As such, the scope and purpose of TIMP is distinct from that of the PSEP. The PSEP decision tree was developed specifically in response to Decision 11-06-017 and is not appropriate or applicable to TIMP.

IV. SOCALGAS AND SDG&E ARE PRUDENT OPERATORS OF THEIR GAS TRANSMISSION SYSTEM

While DRA and TURN do not explicitly comment that SoCalGas and SDG&E are imprudent in the operation of the system, the implication is obvious with statements suggesting that a prudent operator should have all historic records of a pressure test.[29,30] In a similar vein, Utility Workers Union of America suggests that somehow the Commission's directives to implement interim safety enhancement measures indicate that the pipelines included in the Pipeline Safety Enhancement Plan are hazardous to public and employee safety.[31] Such suggestions are unfounded.

SoCalGas and SDG&E take seriously the obligation to maintain their transmission system in a safe operating condition. We are proud of the strong safety record that we have built over the years and we strive to maintain our system in a manner that meets industry safety standards. To that end, SoCalGas and SDG&E have implemented robust Integrity Management Programs in addition to our long-standing routine safety and maintenance practices. Our integrity management programs have significantly increased the level of preventative and

[29] Exhibit DRA-1 Executive Summary and Cost Recovery Policy in R.11-11-002, p. 11-16.
[30] TURN Prepared Testimony of Thomas J. Long, Sempra Utilities' Pipeline Safety Enhancement Plan A.11-11-002, p. 15-16.
[31] Exhibit UWUA-1 Testimony of UWUA Witness Carl Wood in A.11-11-002, page 9 ("They recognize that the pipe under scrutiny is old and leaky, and that until the pipe conforms to 'modern standards for safety' it will continue to pose a hazard to the public and to the employees who work with it every day.").

mitigative activities on our pipeline system as part of ongoing assessments (i.e., as in-line inspections, direct assessment, and integrity-related pressure tests). Any issues identified during these routine or integrity related activities have either been rectified or are being managed within the appropriate program.

As part of our transmission integrity management program, SoCalGas and SDG&E take into account, as the regulations allow, the records that exist for a pipeline when assessing the integrity of that pipeline.[32] In cases where background information is unavailable, or cannot be supplemented with reliable sources or institutional knowledge, more conservative default values are used. As an example, a pipeline acquired from another operating company where complete records are unavailable may result in the designation of a more conservative default value (e.g., pipe with undocumented grade and unknown attributes is assigned a default specified minimum yield strength of 24,000 psi).

Continuous improvements are made to assigned default values. These updates are accomplished through careful review and verification of existing information, newly discovered documentation, institutional knowledge, and knowledge of the system gained through physical inspection of pipe properties. Specific guidelines to determine, document and incorporate these new values based on vintage, manufacturing type, manufacturer, etc. are part of the program.

SoCalGas and SDG&E utilize these guidelines to assign enhanced estimates when data are lacking, using pipeline historical information such as company history, institutional knowledge, and knowledge of pipe characteristics (such as pipeline vintage, manufacturer, long

[32] Subpart 0, incorporates by reference ASME Standard B31.8-S, which provides guidance on the use of unsubstantiated data as part of the integrity management process. ASME B31.8-S, Appendix A, Section 4.4

seam type, etc.) as is an industry-accepted practice.[33] This information in turn is used to determine known pipeline manufacturing practices, develop an understanding of prevailing practices, and estimate or derive missing material properties. In this manner, realistic estimates of the missing data can be derived and supported with the pipeline specifications used during the time of installation, and in data from pipelines that share work orders or purchase orders from similar vintages of pipe. The process continually benefits from improved pipeline knowledge gained through ongoing data collection that results from continued records research, pipeline observations made during inspections, material sampling, or combinations of physical features and known background information.

This approach was developed in accordance with the following guidance from ASME B318.S:

> NOTE: When pipe data is unknown, the operator may refer to History of Line Pipe Manufacturing in North America by J.F. Kiefner and E.B. Clark, 1996, ASME.[34]

The guidance within the ASME Standard acknowledges the value of estimating reasonable values when faced with unknown data. To illustrate this approach, two examples are provided below:

> **Example 1** - Suppose that during the course of pipeline integrity work a flash-welded long seam is observed during exposure of the pipeline for inspection. Using knowledge of the seam type, the grade of material and age of manufacture can be determined accordingly:
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> > "A.O. Smith Corporation made only flash-welded steel pipe in the period between 1930 and 1969. All of it would have been at least Grade A material."[35]

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[33] ASME B31.S, Nonmandatory Appendix A, Section A4.2 (acknowledging missing records, and addressing supplementation of those records using background historical knowledge when available).

[34] ASME B318.S, Nonmandatory Appendix A, Section A4.2.

[35] History of Line Pipe Manufacturing in North America by J.F. Kiefner and E.B. Clark, 1996, ASME, p. 8-5.

Example 2 - Suppose records show a 16-inch diameter pipeline was made by U.S. Steel. This knowledge may also be used to determine likely seam type and minimum pipe grade:

> "In the sizes below 24-inch, all U.S. Steel pipe would be either seamless pipe or high-frequency ERW pipe. The minimum grade would be Grade A."[36]

In this manner, knowledge of the pipeline diameter can be combined with known manufacturing processes to improve upon previously missing and unknown pipeline data.

What intervenors fail to understand is that recordkeeping alone is not the singular barometer of true pipeline integrity, and should not be the sole view into comprehensive integrity management; a fully integrated and developed understanding of pipeline integrity equally includes knowledge of historical operation, maintenance practices, and pipeline condition. This understanding is reflected in our April 15th Report:

> During the course of their records review, SoCalGas and SDG&E did not discover any documented inconsistencies that would call into question the standard engineering practices used through the years, nor cause concern regarding the current pressure-carrying capacity of in-service pipelines. Gas pipelines are manufactured, designed and constructed to safely operate at MAOP, and throughout their operating histories SoCalGas and SDG&E have employed industry standard engineering practices to provide appropriate margins of safety. SoCalGas and SDG&E are confident those line segments are operating safely and in compliance with current regulatory requirements.[37]

These efforts, along with the investments that we have made enabling much of our system to be piggable, as well as the active participation in industry groups such as American Gas Association, Pipeline Research Council International and American Society of Mechanical Engineers to advance the state-of-the-art in integrity management, are all part of our comprehensive approach to managing our systems in a safe operating condition.

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[36] History of Line Pipe Manufacturing in North America by J.F. Kiefner and E.B. Clark, 1996, ASME, p. 8-8.
[37] Report of Southern California Gas Company and San Diego Gas & Electric Company on Actions Taken in Response to the National Transportation Safety Board Safety Recommendations, p. 10.

V. DRA AND TURN'S RECOMMENDATION THAT THE COMMISSION REJECT SOCALGAS AND SDG&E'S PROPOSED CASE IS MISGUIDED

In an apparent effort to reduce costs, DRA and TURN recommended that the Commission reject SoCalGas and SDG&E's proposed case. This is shortsighted. SoCalGas and SDG&E's proposals to replace wrinkle bends and girth welds and to replace non-state-of-the-art pre-1946 transmission pipelines are intended to comply with the directive in D.11-06-017 to consider, among other things, the retrofitting of pipelines to allow for in-line inspection tools and to enhance the overall safety of natural gas transmission pipelines in California.[38]

A. Contrary To What Intervenors Say, SoCalGas And SDG&E's Proposals On Wrinkle Bends Should Be Adopted.

DRA's recommendation that wrinkle bends be addressed only through TIMP fails to improve the safety of the transmission system in a cost-effective manner and fails to recognize several important factors, namely:

1. That TIMP activities apply primarily to pipelines within HCA, and that the scope of the PSEP extends well beyond these HCA limits to all transmission pipeline, and
2. That construction related threats such as wrinkle bends are typically considered stable under TIMP, yet may still fail during a widespread destabilizing event such as an earthquake or continuous heavy rainstorm episodes.

[38] D.11-06-017, item #8, p. 32.

The Commission has stated it is resolute in its commitment to improve the safety of natural gas transmission pipelines.[39] The outages associated with pressure tests under the Pipeline Safety Enhancement Plan provide an ideal window of opportunity to cost effectively remove wrinkle bends with minimal additional disruption to service and enhance the safety of the transmission system.

While the pipeline rupture in San Bruno has placed primary focus on the need for post construction pressure tests to validate the integrity and stability of a pipeline's long seam, the stability of all manufacturing and construction threats, including wrinkle bends, are receiving greater scrutiny. Indeed, current pipeline integrity regulations focus on the issue of defect stability as the trigger to determine the appropriate integrity assessment methods related to both manufacturing and construction defects.

In addition, significant girth weld flaws were observed during the NTSB failure investigation.[40] Vintage welds of similar quality pose a potential risk during any earth movement event, even if currently recognized as stable under normal operating conditions. The same risk applies to wrinkle bends or other field fabricated construction threats that are subject to permanent ground displacement.

DRA offers the following statement in their PSEP testimony, "In its Test Year 2012 GRC, Sempra did not identify the issue of wrinkle bends as a threat to its system and failed to propose a system-wide accelerated replacement of wrinkle bends in that proceeding."[41] This statement is false. In fact, wrinkle bends are addressed in the TY2012 GRC proposal (see Exhibit SCG-05-CWP-R, page RKS-CWP-182-R). The approximately 160 wrinkle bends

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[39] D.11-06-017, Section 3 discussion.

[40] Pipeline Accident Report, Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, National Transportation Safety Board, p. 43.

[41] DRA Exhibit 2 Prepared Testimony of D. Phan in A.11-11-002 SoCalGas and SDG&E PSEP, p. 32.

identified as part of the GRC are in addition to the approximately 4,000 wrinkle bends identified in PSEP. The GRC proposal is addressing wrinkle bends in response to the TIMP regulations where they are located within HCA identified for ground movement, and were not included as part of PSEP. The wrinkle bends addressed as part of PSEP are to take advantage of the opportunity to remove these non-state-of-the-art field bends that cannot be effectively assessed using pressure test, in-line-inspection or direct assessment, yet are considered stable per current regulations.

It is disingenuous of DRA to use SoCalGas' request for $25 million in TIMP funding in its O&M non-shared GRC filing as a point of contention to deny the removal of wrinkle bends as part of PSEP when DRA itself proposed funding only $11.1 million for TIMP (Exh. DRA-44). DRA's proposed underfunding was based on their mistaken belief that, as of 2009, SoCalGas had already completed all of its baseline assessments required by TIMP. SoCalGas explained in rebuttal that baseline assessments were not complete, and would continue through 2012. Even when this misunderstanding was clarified in rebuttal, DRA did not re-evaluate their position and held firm on their desire to underfund the TIMP program, while discounting all of the work proposed in testimony and workpapers. DRA chose to ignore all of the requested funding based on documented project requirements, and instead favored a historical 5-year average cost that does not address the project specific requirements laid out in the GRC filing.

SoCalGas and SDG&E have, in fact, evaluated their transmission system based on the TIMP requirements and requested the necessary funding to complete the "management" of the threats to its pipeline system in its TY 2012 GRC. But as stated, the transmission pipelines covered by PSEP are broader than those covered by TIMP, and the funding requested in PSEP is incremental to that requested in the GRC. That is why the funding from removing the 160 wrinkle bends requested as part of the GRC is not included in our PSEP filing.

If the proposal for removal of these wrinkle features is not approved as part of the PSEP, SoCalGas/SDG&E urge the Commission to consider the possibility of selected mitigation of a higher risk subset of wrinkle bends present on affected pipelines. A selective approach, while not as comprehensive as full mitigation of the threat, will at least result in a targeted reduction in the overall risk associated with these features while taking advantage of the planned outage for pressure testing.

B. SoCalGas And SDG&E's Proposal To Replace Non-Piggable Pre-1946 Pipelines Should Be Adopted

Contrary to the intervenor's interpretations, SoCalGas and SDG&E's proposal to replace non-piggable pre-1946 pipelines is consistent with the Commission's order that pipelines "…where warranted, be capable of accommodating in-line inspection devices"[42] and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested.

As part of the Transmission Integrity Management Program, some pre-1946 pipelines were retrofitted and in-line inspected to assess for damages (dig-ins) and corrosion. Since these lines can accommodate modern inspection technologies (smart pigs), and the capability of these technologies continues to expand, they have been identified for pressure testing as part of the PSEP. Those pre-1946 transmission lines that have not been retrofitted and cannot accommodate in-line inspection tools have been identified for replacement as part of PSEP in order to meet the Commission directive to expand the system piggability as well as enhance transmission pipeline

[42] Page 20 of Decision 11-06-017.

safety in a cost-effective manner. Given that the integrity of these pre-1946 transmission pipelines cannot be assessed using the most advanced technology, and the time and cost to complete a pressure test may be substantial, it does not make sense to pressure test these pipelines. While DRA is correct when they state that these aged pipelines can continue to be maintained for normal operation, DRA fails to recognize that pressure testing of these pipelines is well in excess of normal operation.

Pre-1946 pipelines were built using non-state-of-the-art construction methods (i.e., oxy-acetylene welds that are inherently brittle), were not designed to be hydrotested post construction, and are relatively more likely to develop leaks on girth welds or experience other failures at elevated test pressures that will be costly to locate and repair. The same elevated risk of failure is also true for these pipelines with regard to the possible presence of non-state-of-the-art system additions, modifications and repairs that may not be suited for the elevated test pressures. These factors add a higher degree of uncertainty during the test compared to pipelines that have been in-line inspected or were constructed at a later date.

DRA's suggestion that a pressure test is sufficient for these aged lines is short-sighted and fails to recognize that while a remote possibility exists that pressure testing may remove flaws that are on the verge of failure, it is well-established in the industry that the circumferential orientation and size of typical girth weld flaws is such that they are relatively insensitive to the effects of pressure testing. Performing only a pressure test on these non-piggable, non-state-of-the-art constructed pipelines will thus leave a population of potential flaws in service that may be considered stable, yet will remain prone to future failure during earth movement events.

Replacement of these aged pipelines will further drive down the risk associated with those remaining and otherwise stable flaws. The elevated test pressures, water removal challenges, and inability to inspect using state-of-the-art equipment and inability of the pressure test to validate the integrity of the girth welds in an earthquake when taken together, clearly indicate that the time has come for these aged pipelines to be replaced.

C. TURN Mistakenly Believes That Funding For Mitigation Of Pre-1946 Pipeline Features And Wrinkle Bends Should Be Rejected Based Upon The Capabilities Of Newly Emerging Robotic In-Line Inspection Technology

TURN believes that newly developed robotic in-line inspection technology is capable of inspecting pre-1946 pipelines and wrinkle bends, and may therefore serve as the basis to reject funding for mitigation of pre-1946 construction features. According to their testimony:

> Probably the most important reason for rejecting this request as this time (or scaling it back substantially to spend O&M rather than capital dollars) is because new technology – invented with the help of R&D money funded by SoCalGas ratepayers – is making it possible to inspect lines that were previously "unpiggable."[43]

It was also noted by TURN that battery powered self-propelled tools are being developed to deploy inspection technologies in pipelines that either do not have sufficient pressure and/or flow to move conventional in-line inspection tools or, in some cases, have a configuration that could obstruct passage of the conventional inspection devices. TURN's testimony notes:

> The research arm of the Northeast Gas Association (NYSEARCH) has been developing innovative robotic, remotely-controlled, self-powered, in-line inspection technology for unpiggable pipelines with Pipetel Technologies, Inc.. SoCal spent its R&D money to field test some of this equipment on at both the 8 inch and 20-26 inch robots. This technology now exists for pipelines of 6-8 inches in diameter (Explorer 6-8) and will be commercialized in diameters up to 14 inches (Explorer 10-14) and in the 20-26 inch range (TIGRE) in 2011-2012.

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[43] Prepared Testimony of W.B. Marcus on behalf of The Utility Reform Network A.11-11-002 (Sempra Triennial Cost Allocation Proceeding, PSEP Phase), p. 21.

> The basic technology can be applied to other line sizes, and work is being done to make the robotic technology available for more line sizes.[44]

While SoCalGas and SDG&E are strong proponents and supporters of the development of self-propelled robotic inspection tools, we recognize that these tools are limited by the existing capabilities of these devices, as well as their relatively limited availability.

In-line inspection technology can be conceived as a two part system: the "vehicle" or platform used to deploy the inspection sensors, and the sensor technology used to detect anomalies. It is important to realize that the major advances and development work in the area of this new robotic technology lie in the development of a robotic platform that can overcome the typical factors that impede the use of conventional in-line inspection tools (namely pipeline geometry, gas pressure, and gas flow rate). Like all inspection methods, robotic inspection devices have advantages and limitations, and the current capabilities of these new devices make them best suited for short length applications with difficult geometry, flow, or access.

Expected applications include short, non-piggable pipe segments that are under freeways, in casings, or otherwise in locations that cannot be readily exposed. At each of these locations, a fitting will need to be welded onto the pipe, and access added to allow the robotic tool to enter and exit while the pipeline is in service. For a variety of reasons (chief among these being battery life between recharges) this technology is not currently capable of inspecting long lengths of pipeline. Similar to conventional tools, depending upon the pipe configuration the tool can inspect about a mile of pipe per day for wall loss typically associated with corrosion. While the applicability of this self-propelled technology will expand to carry additional inspection methods

[44] Prepared Testimony of W.B. Marcus on behalf of The Utility Reform Network A.11-11-002 (Sempra Triennial Cost Allocation Proceeding, PSEP Phase), p. 22.

and address larger diameter pipe, it will likely be at least a decade before a full suite of inspection methods using variety of technologies across multiple diameter ranges is available.

D. DRA States That In-Line Inspections, Including TFI, Performed Before Pressure Testing Should Be Rejected Because The Pipelines Are Presumed To Have Been Recently Inspected Under The TIMP And Will Duplicate Work And Ratepayer Expenditures

DRA incorrectly believes that the standard magnetic flux leakage technology is used to inspect long seam flaws. DRA also takes issue with outcome 5 on the decision tree (shown on page 4), which identifies the in-line inspection of piggable pipelines using transverse flux inspection (TFI) technology prior to pressure testing. DRA's rejection of the proposal is based upon the incorrect belief that the previous inspection using standard axial magnetic flux leakage (MFL) technology will adequately assess the long seam. DRA fails to understand the differences in the technologies, or the fact that the SoCalGas and SDG&E proposal is strictly for the incremental forecast costs of using the TFI tool, and that the costs associated with using the standard MFL are not included in the PSEP, as these costs were included in the general rate case filing.

DRA misunderstands that the TIMP-related inspections performed to date have primarily used axially oriented magnetic flux leakage tools that are not sensitive to the long seam condition. While the axial tools may detect gross volumetric flaws in the long seam, this technology is not sensitive to axially oriented narrow flaws associated with seam issues.

The physics of TFI tools, in contrast, are far more sensitive to targeted evaluation of the long seams to inspect for the same manufacturing flaws that are the focus of the PSEP, and are identified as stable under TIMP. This difference in inspection ability is clearly defined in TIMP, and referenced in ASME B318.S, where assessment methods must be specifically tailored to the threats under evaluation.

Further, TFI inspections have not been a requirement of the SoCalGas/SDG&E TIMP assessments to date, and thus use of this specific inspection technology is not redundant with the axial MFL inspections that have been utilized so far. The assertion that duplication with TIMP should be the basis for rejecting our proposed use of TFI ignores the numerous responses provided to DRA covering this very topic. In one response, when asked why SoCalGas and SDG&E are requesting funds in the PSEP to perform reassessments that are part of TIMP, these issues were made clear in the following response:

> SoCalGas and SDG&E are not requesting any funding to perform activities already planned as part of TIMP. The proposed TFI inspections are incremental to TIMP-related activities. There are no pipelines for which a TFI tool run would supplant IMP activities, and TFI inspections were not contemplated as part of our most recent General Rate Case Applications. Please see section IV.B.2.c on page 49 of our Testimony, and additionally refer to pages 11-13 in our February 24, 2012 Comments on the Technical Report of the Consumer Protection and Safety Division for a complete description of our proposed use of incremental TFI inspections as part of the plan to satisfy the Commission's directives in Decision 11-06-017.[45]

It makes sense to leverage the investment made in these pipelines and gather additional long seam data using TFI technology that is above and beyond what is required by TIMP and what was requested in the last General Rate Case. Removal of critically sized flaws on the long seam prior to the pressure test is in the best interest of all parties. The Commission should support the use of TFI as a cost-effective measure not only to prevent failures during pressure testing, but to also identify and permanently remove flaws that are of a critical size and further improve the safety of the transmission system.

[45] Data Request DRA-DAO-21-01.

SoCalGas and SDG&E's proposed TFI assessments are also in keeping with the guiding principle of long-term cost effectiveness for our customers. Cost avoidance associated with pressure test failure disruptions, and the potential long-term benefit of cost savings in Phase 2 if TFI (and our proposed use of non-destructive evaluation) is adopted as an acceptable equivalent to pressure testing, are the basis for this proposed approach. DRA should recognize and support the opportunity to achieve the significant cost savings potential on behalf of ratepayers. Witness Harvey H. Haines in his testimony provides a detailed discussion of both TFI and non-destructive evaluation, their role in assessing pipeline condition, and how they can be applied as equivalent alternatives to pressure testing.

It should also be noted that §696 was recently added to the California Public Utilities Code and requires that expenses for the transmission integrity management program be placed in a balancing account.[46] All costs associated with TIMP will be subject to this balancing account rules, and PSEP costs will be subject to the rules the Commission determines during this proceeding. Expenses will be accounted for in the appropriate balancing account (PSEP or TIMP), and will be included in one or the other, not both. Additional information on the accounting of the PSEP expenses is included in the testimony of Edward Reyes.

VI. CONCLUSION

SoCalGas and SDG&E's Pipeline Safety Enhancement Plan meets what the Commission ordered natural gas operators to do in D.11-06-017. SoCalGas and SDG&E's Pipeline Safety

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[46] California Public Utilities Code §696: In any ratemaking proceeding in which the commission authorizes a gas corporation to recover expenses for the gas corporation's transmission pipeline integrity management program established pursuant to Subpart O (commencing with Section 192.901) of Part 192 of Title 49 of the United States Code or related capital expenditures for the maintenance and repair of transmission pipelines, the commission shall require the gas corporation to establish and maintain a balancing account for the recovery of those expenses. Any unspent moneys in the balancing account in the form of an accumulated account balance at the end of each rate case cycle, plus interest, shall be returned to ratepayers through a true-up filing. Nothing in this section is intended to interfere with the commission's discretion to establish a two-way balancing account.

Enhancement Plan accomplishes the intent of the Decision to cost effectively end historic exemptions and pressure test or replace transmission pipeline. The testing and replacement ordered to be included in the plan are incremental actions beyond what is required by the transmission integrity management program and are prioritized in accordance with the Decision. In addition, the costs to perform these programs shall be tracked and recovered separately and not be duplicative. As part of its plan, SoCalGas and SDG&E have also proposed the replacement of non-state-of-the-art wrinkle bends, pipe and girth welds in accordance with the Commission's commitment to enhance the safety of natural gas transmission pipelines, and additionally the clear directive in D.11-06-017 to consider, among other things, the retrofitting of pipelines "to allow for in-line inspection tools." Lastly, requirements for post construction pressure testing were first required in California per General Order 112 in 1961, with the Subpart J test becoming effective in 1970.

This concludes my testimony.

CHAPTER 7

ALTERNATIVE ASSESSMENT METHODS

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PREPARED REBUTTAL TESTIMONY

OF HARVEY H. HAINES

I. INTRODUCTION

This testimony responds to the prepared direct testimony of intervening parties to Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company's (SDG&E) Proposed Natural Gas Pipeline Safety Enhancement Plan. Specifically, this testimony responds to claims made primarily by the Division of Rate Payer Advocates (DRA) that:

A. SoCalGas and SDG&E's Pipeline Safety Enhancement Plan use of circumferential magnetic flux leakage (CMFL, sometimes called TFI) or in-ditch non-destructive evaluation (NDE) is not an equivalent means to assess defects that could fail a hydrotest (D.11-11-002).

Intervenors misunderstand the equivalence of ILI, NDE, and hydrostatic pressure tests.

II. SUMMARY OF CONCLUSIONS

A. Pipelines fail because of flaws present in the pipe steel. The key to maintaining integrity is to remove any flaws that remain in the pipeline that are close to failure. These flaws may be introduced during manufacturing and remain in the pipeline since it was constructed as in the case of the San Bruno, CA failure.

B. Pressure testing and In-Line Inspection (ILI) measurements are both effective methods of removing flaws that can fail in a pipeline. Pressure testing removes flaws by testing to a pressure above the operating pressure. The ratio of the test pressure above the operating pressure is called the test margin. In-Line Inspection tools have the ability to obtain a test margin as large as that required by pressure testing. The advantage of using a measurement to detect and size defects is that defects can be located well before they reach the critical size allowing both the ability to repair critical defects prior to failure, and monitoring of less serious defects over time.

C. Circumferential magnetic flux leakage (CMFL) or TFI has been an effective method for detection of flaws in the seam weld of pipelines and is the method of choice for many liquid operators who must perform periodic tests of their seam welds if susceptible to pressure cycle fatigue crack growth. A defect in the seam weld was the initiation site of the San Bruno, CA failure. The current preferred ILI technique to use for inspecting seams is the CMFL tool, although other tools show promise of being good seam inspection tools in gas pipelines. Although inspection of the seam is paramount in eliminating defects that could have gone undetected in the seam weld during manufacturing it is also important to inspect the pipe body in addition to the weld zone.

D. ILI is often used prior to a required hydrotest to identify, locate, and remove or repair flaws that would fail a hydrotest. This can prevent a potentially costly process of keeping a pipeline out of service during a hydrotest as each flaw is discovered. In addition for new ILI technologies that have the potential to increase pipeline safety and/or reduce the cost of maintaining safety, this combination gives the operator and regulator additional assurance the newer technique (ILI) is indeed equivalent to the more established technique (pressure testing) and can be used effectively on its own for future integrity testing.

E. In-ditch NDE of entire joints should be as good as or better than an ILI and is an acceptable method for inspection of short segments that can be exposed, as long as the NDE includes a record of the data collected that allows verification by another individual qualified to interpret such records.

III. QUALIFICATIONS

I am qualified to submit this testimony by training and experience in measurements since 1982. I have been employed starting in 2002 by Kiefner and Associates, Inc. (KAI) a Worthington, Ohio consulting firm that provides technical services to oil and gas pipeline operators and pipeline industry groups, including pipeline failure investigations, fitness for service assessment, integrity assessment procedures including in-line inspection assessments, risk assessment, codes compliance, research, training , and other services. My current position is Senior Pipeline Specialist.

During my employment with KAI I have provided consultation to numerous oil and gas pipeline operators in technical matters related to in-line inspection measurements, operational reliability assessment, and training. I co-teach a KAI workshop on Pipeline Reliability Assessment several times per year, where the various causes of pipeline failure are presented including a discussion of pipeline defects and pipe properties. We spend the significant portion of the workshop discussing the advantages and disadvantages of assessing pipeline threats using ILI, hydrotesting, and direct assessment.

Prior to joining KAI, I was employed by the Gas Research Institute (GRI) for 11 years, including 7 years as the program manager responsible for development of ILI inspection technologies for the U.S. Gas industry. I was responsible for a $5 million annual budget dedicated to understanding and improving ILI technology for detection and sizing of all defects in pipeline steels. Projects included efforts to better understand the sizing capability of magnetic flux leakage (MFL) technology, including efforts to understand circumferential MFL (CMFL). Another major effort was to develop electromagnetic acoustic transducer (EMAT) technology to detect and size cracks in the pipe body and adjacent to the long seam. In the 4 years at GRI prior to joining the transmission pipeline group, I was responsible for cased-hole logging R&D in the exploration and production group.

Prior to joining GRI in 1990, I spent 8½ years with Chevron as a petrophysicist evaluating rocks using non-destructive geophysical measurement techniques. These geophysical measurement techniques are very similar to the techniques used for NDE of pipeline steels.

My academic training is as a geophysicist with B.S. 1980 and M.S. 1982 degrees from the Massachusetts Institute of Technology.

I am a current member of NACE International, the SPWLA, and a committee member of the PRCI Operations and Inspection Technical Committee.

IV. MATERIAL REVIEWED

[1] Duffy, A.R., McClure, G.M., Maxey, W.A., Atterbury, T.J., "Study of Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure," PRC/AGA research report, February 1968.

[2] Kiefner, J.F., and Clark, E.B., "History of Line Pipe Manufacturing in North America," ASME Research Report DRTD-Vol. 43, 1996.

[3] Kiefner, J.F., Maxey, W.A., and Eiber, R.J., "A Study of the Causes of Failures of Defects That Have Survived a Prior Hydrostatic Test," PRC/AGA report No 111, November 3, 1980.

[4] Kiefner, J.F., "Modified Equation Aids Integrity," Management Oil & Gas Journal Oct 6, 2008.

[5] Morris, W.G., and Haines, H.H. "Pipeline Reliability Assessment Workshop" presented to federal and state regulators at The Federal Transportation Safety Institute in Oklahoma City, April 26-27, 2011 and previous years.

[6] Rosenfeld, M.J., "Application of Integrity Assessment," Presentation to the CPUC, June 24, 2011.

[7] Code of Federal Regulations Part 192 Subpart L – Operations, Subpart J – Hydrostactic Test Requirements, and Subpart O – Pipeline Integrity Management.

[8] Rosen tool specifications for the RoCorr™ – CMFL tool, 2012.

[9] GE PII Crack Detection tool Specification for the CMFL TranScan™ inspection tool, 2010.

[10] Managing System Integrity of Gas Pipeline, ASME B31.8S-2010, Section 6.1

V. EQUIVALENCY ARGUMENT

The concept of assuring the fitness for service of a pipeline using pressure testing versus detecting and sizing defects has been demonstrated many times for pipelines. Mike Rosenfeld of Kiefner and Associates gave a presentation to the CPUC on the subject on June 24, 2011[6]. The concept is based on the known fact that pipelines do not fail unless a flaw is present in a pipeline that will reduce the failure pressure of a pipeline to the point where the pipeline will fail [1],[5]. Such a defect is termed a "critical defect."

The relationship between critical defects and failure pressure is often represented as a cross-plot with flaw length on the x-axis, flaw depth on the y-axis, and a series of curves representing the failure pressure for a given flaw depth and length. This type of cross-plot is presented below in figure 1, and was used by Mike Rosenfeld in his June 2011 presentation. Flaw depth (d) is usually expressed as a fraction of wall thickness (t) or d/t, where a flaw with a d/t of 0.6 would be 60% through-wall.

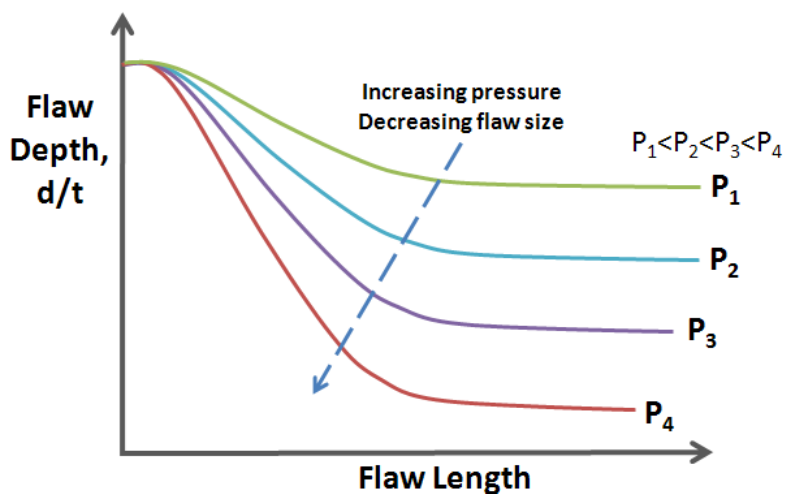

Figure 1, A Critical defect length and depth for different pressure levels.[6]

The cross-plot is often inverted with flaw depth and failure pressure interchanged, where flaw length is still on the x-axis, but failure pressure is on the y-axis with depth of a critical defect represented by a series of curves on the graph. Both plots demonstrate the relationship between depth, length, and pressure, where larger defects lead to lower failure pressures. This later type plot is usually easier to calculate and is the type of plot used in this testimony to represent the equivalency of a pressure test and an examination for defects of a critical size that could fail in-service.

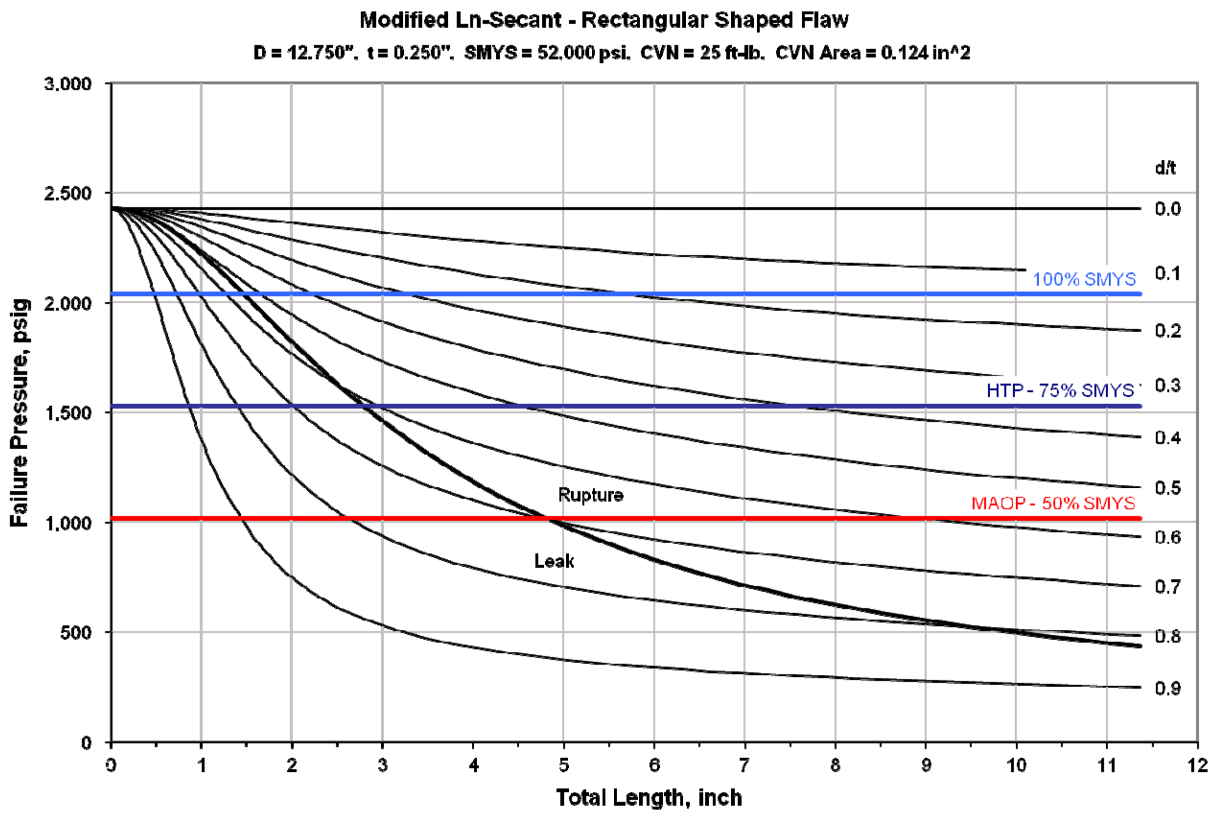

Figure 2, Critical defect length and failure pressure for different defect depths given a specific pipe material.

Figure 2, above is a cross-plot where the depth of a defect at failure is calculated for a 12-inch diameter by ¼-inch wall thickness with a pipe strength of 52,000 psi.[1]

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[1] The modified log-secant [4] assessment equation is used to calculate depth curves for sharp flaws such as crack-like seam weld flaws. For blunt flaws such as corrosion in the pipe body, a different assessment equation such as the modified B31G equation is often used to produce a similar plot.

Superimposed on the plot is a case for a gas pipeline in a class 3 location, where the maximum allowable operating pressure (MAOP) is 50% of the specified minimum yield strength. Current regulations for new class 3 pipe must be pressure tested to 150% of MAOP which is 75% of specified minimum yield strength (SMYS) for a pipeline with an MAOP of 50% of SMYS. Pipe will not fail until a defect that contains a flaw exceeds the flow stress, which is calculated as 10,000 psi above SMYS in the modified log-secant equation and other commonly used assessment equations. This agrees with experience where shallow defects of 10% to 12% wall thickness or less do not fail even at 100% of SMYS.

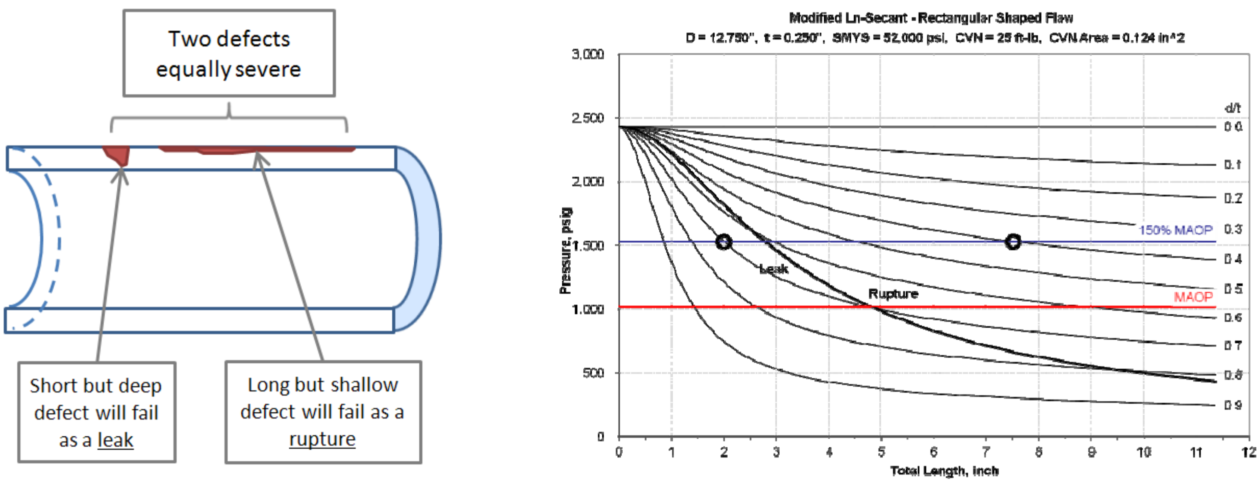

Figure 3, A 2-inch long 70% deep defect will fail at the same pressure as a 7½ inch long 40% deep defect, although the shorter deep flaw will fail as a leak where the longer shallower flaw will fail as a rupture.

The family of curves representing different depth flaws at failure shows that deeper flaws will fail at lower pressures. For a flaw of a given depth, shorter flaws produce higher failure pressures. In general long shallower flaws will fail as ruptures and deeper short flaws will fail as leaks. An example of this is represented above in figure 3. Two defects that will fail at the same pressure are considered equally severe. A 2-inch long 70-percent deep flaw will fail at the same pressure as a 7½-inch long 40-percent deep flaw, the difference being the short 2-inch flaw will fail as a leak and the long 7½-inch flaw will fail as a rupture.

We have shown that if the flaw size can be measured for a pipe material of known diameter, wall thickness and strength, the failure pressure can be calculated. For these situations, a tool that can measure defect sizes (i.e. ILI, NDE) can be equivalent to pressure testing.

The advantage of using a measurement to detect and size defects is that defects can be located well before they reach the critical size allowing both the ability to repair critical defects prior to failure, and monitoring of less serious defects over time.

Improvements and acceptance of ILI and NDE technology is reflected in the Code of Federal Regulations. When the Federal Regulations were written in 1970 only hydrostatic testing was included as an integrity test in-part because ILI technology was still in its infancy and did not exist as a practical equivalent to pressure testing. Current Subpart O regulations [7], which were implemented in 2004 allow for (1) ILI, (2) hydrotesting, (3) Direct Assessment (DA), or (4) Other technology to be used for ongoing integrity threats reflecting advances in integrity management technology beyond hydrotesting. When performing a hydrotest Subpart O refers back to Subpart J from these initial 1970 regulations and states that a "pressure test must be performed in accordance to Subpart J" essentially stating that Subpart J and ILI are acceptable methods as long as they are each capable of addressing a susceptible threat. Under current industry practice before the San Bruno incident, seam weld manufacturing defects were considered stable for gas pipelines. San Bruno demonstrated to the gas pipeline industry the necessity of demonstrating a sufficient safety margin to consider seam defects stable and no longer a susceptible threat. If a pipeline has never been hydrotested then a flaw could have existed in the pipeline close to failure for decades. ILI capable of inspecting the seam can be used to find large flaws in the seam that could be on the verge of failure. If found these flaws can be removed or repaired before a leak or rupture occurs. In addition a 100% NDE inspection of a joint should qualify as a substitute for ILI as in-ditch NDE measurements are used to qualify ILI tools and are allowed in B31.8S Section 6.1 [10]. “The operator may choose to go directly to examination and evaluation for the entire length of the pipeline segment being assessed, in lieu of conducting inspections.” The ILI or NDE method(s) used must be capable of addressing the susceptible threats.

When using methods in undocumented pipe that size defects such as ILI or NDE, a concern is that undocumented pipe properties such as strength, diameter, and wall thickness are needed to calculate predicted burst pressure. Although diameter and wall thickness can be determined from ILI or NDE measurements, currently the only generally accepted measurements for pipe strength are destructive tests made in the laboratory, because currently there is no generally accepted NDE measurement for pipe strength. This results in increased uncertainty for a pipe segment operating with undocumented pipe strength, when using ILI or NDE to assess the flaws in the pipe. This should not preclude using measurement to detect and size defects. Uncertainty of pipe strength can be overcome with reasonable engineering judgment such as the use of conservative values based on known pipe characteristics. If the quantity of defects is not large (as is commonly the case for seam defects) then the opportunity to repair all flaws can be used to provide for an increased level of safety from inspection when pipe strength is unknown.

VI. USE OF CMFL (OR TFI) FOR CRITICAL DEFECT DETECTION

Magnetic Flux Leakage (MFL) is the most commonly used in-line inspection measurement for gas pipelines. This technique has been established in industry as the preferred method for detecting and sizing corrosion metal-loss in the pipe body. However, when used in its conventional arrangement with axial magnetization, this type of inspection technology is poor at detecting defects in the long seam.

Conventional MFL uses a magnetizer that has poles that are spaced a fixed distance apart inside the pipe. This is the easiest and best way to set up a uniform magnetic field in the pipe wall. When the pipe wall is thinned from metal loss the remaining steel can no longer carry or conduct as much magnetic flux and the flux is forced out of the pipe wall with an increase both inside and outside the pipe. Sensors inside the pipe on an ILI tool can pick-up this increase in flux, the amplitude and dimensions of the flux increase can be related to the volume (length, width, and depth) of the metal missing from the pipe wall. Because the magnetizer is axially oriented the flux lines are axially oriented and defects that are axially oriented produce the smallest signal disturbance and the smallest and least reliable signals. Defects in the seam have near perfect axial orientation and are thus the least reliably detected using conventional MFL tools.

To address the inspection of axially oriented flaws, tools were developed by British Gas in the 1990s to target detection of seam defects by orienting the magnetizer in the circumferential or transverse direction. British Gas called their tool transverse field inspection or TFI. These tools are generically described as circumferential magnetic flux leakage (CMFL) tools with TFI often considered a trade name of the developer of the first commercial CMFL tool. CMFL tools have different specifications for detecting defects depending upon the vendor. Figure 4 below shows the specification [8][9]for the two vendors with the most experience running CMFL tools. Both show detection limits which result in a higher level of safety from an ILI inspection than with a conventional 150% pressure test for the class 3 example shown.

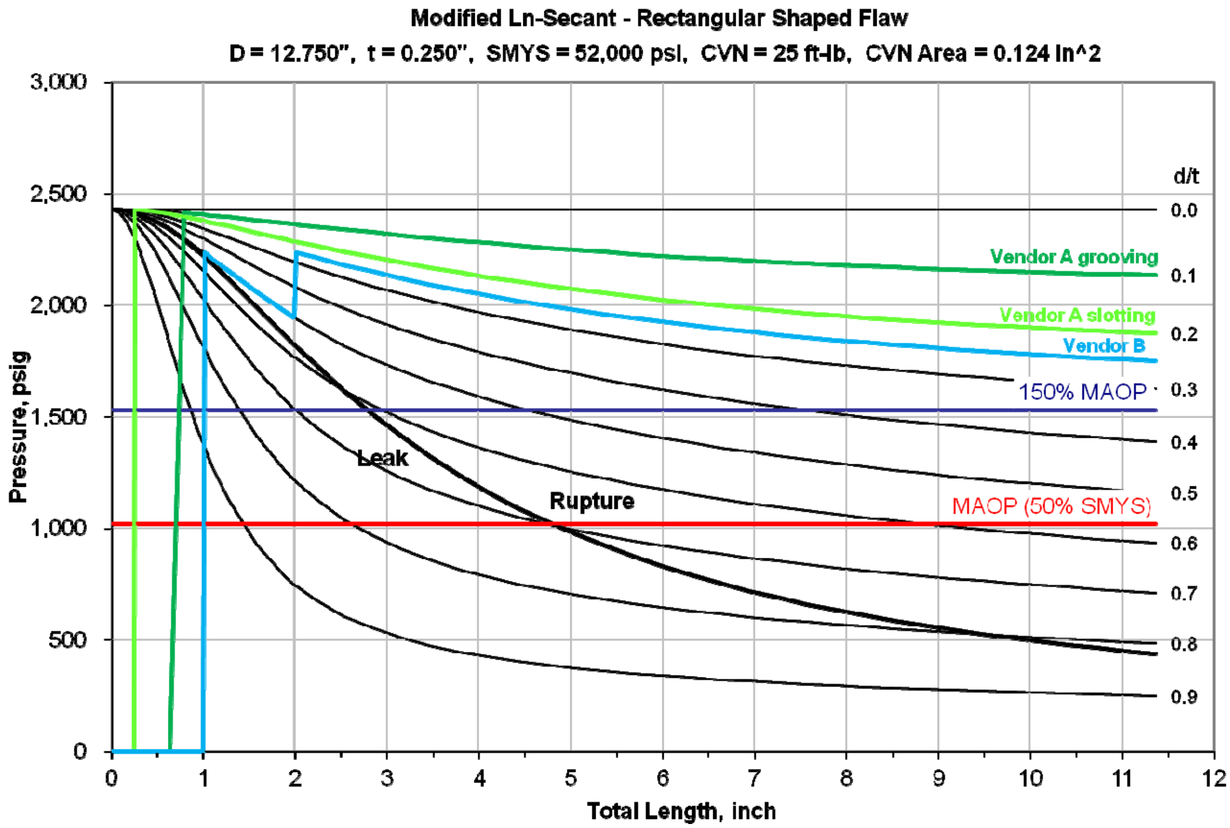

Figure 4, Detection thresholds for commercial CMFL tools show smaller defects are detected using ILI if pipe parameters are known.

From figure 4 it is apparent that CMFL has the ability to detect smaller defects than would fail by hydrostatic pressure test. For the most severe defects that can fail as ruptures, defects that are almost 5-inches long or longer, figure 4 shows that CMFL has the ability to find smaller shallower defects than hydrotesting. Therefore, both techniques can find so called subcritical defects, or defects that are too small to fail at MAOP.[2] Results are similar for pipelines operating at moderate stress levels, e.g. Class 2, 3, & 4.

CMFL is currently the assessment technology most widely used by liquid pipeline operators to manage seam anomaly growth caused by pressure-cycle-induced fatigue. Gas

[2] The figure shows that for short defects of approximately 1-inch or shorter neither technique works well 100% of the time for finding defects. But because these defects are short they fail as leaks and are often detected using above ground leak detection surveys.

operators have typically not used CMFL because the light pressure cycles experienced in gas pipelines do not typically cause seam anomaly growth except in large flaws whose size can allow the flaw to grow to a critical defect size at the maximum allowable operating pressure even with light pressure cycles.

One of the issues with older pipelines is having records that establish pipe properties for segments of the pipeline. An issue of current concern is determining pipe strength or more specifically Specified Minimum Yield Strength (SMYS). It is important to realize that both ILI and pressure testing can find subcritical defects even if they are not capable of measuring pipe strength (unless the hydrotest pressure is increased until the pipe yields which is not required by current regulations). If the pipe strength is not as good as specified, then a pressure test will remove smaller defects than predicted using SMYS and the assessment equations, but the safety margin will remain the same. For an ILI tool if all of the detectable flaws are repaired, the increased margin of safety using an ILI tool will be reduced, but the pipeline will still remain safe because defects close to failure are removed or repaired.

Newer technologies such as ILI need to be allowed for operators to use the most appropriate technology for managing integrity. In cases where it is difficult to take a line out of service because it might cause disruption to the customer and the line is “piggable,” in-line inspection is the obvious choice for managing integrity. The CPUC led the federal government in the 1960s by implementing pipeline safety regulations almost a decade before the US DOT. The CPUC has the opportunity to repeat that regulatory lead here by allowing the forward looking technology of ILI to be used for inspecting pipeline seams that have a potential to fail because a potential threat exists, rather than relying solely on the older pressure testing regulations cited in the NTSB recommendations. There is nothing wrong with using pressure testing to establish a margin of safety; however ILI is currently capable of doing the same albeit with advantages and disadvantages over hydrotesting.

Unlike hydrotesting which is a mature technology, ILI continues to improve as new methods of detecting and sizing flaws are possible. Newer technologies are capable of detecting seam weld anomalies such as EMATs and helically oriented MFL, although neither has been proven to the extent that CMFL has and neither is currently being requested by SoCalGas or SDG&E as an alternative the hydrostatic testing. Because ILI technology is evolving, performance based specifications should be used to qualify its use in lieu of specifying a particular technology.

ILI is often used prior to a hydrotest to identify, locate, and remove or repair defects that would fail a hydrotest. This can prevent the potentially costly process of keeping a pipeline out of service during a hydrotest as each flaw is discovered. In addition for new ILI technologies that have the potential to increase pipeline safety and/or reduce the cost of maintaining safety, this combination gives the operator and regulator additional assurance that the newer technique (ILI) is indeed equivalent to the more established technique (pressure testing) and can be used effectively on its own for future integrity testing. During hydrotesting only one flaw is usually discovered on each pressurization, usually before the desired test pressure is reached, but sometimes during the 8-hour hold period at the test pressure. If a break occurs the flaw must be located and removed before the pipeline segment can be repressurized in an attempt to reach and maintain the required test pressure. Each pressurization usually takes 24 hours. If many breaks are encountered during testing a pipeline segment, then hydrotesting can result in an extended service outage. In an attempt to minimize any outage, especially on critical line segments, operators often try to find and remove or repair as many flaws as possible to minimize downtime through the use of ILI before the pressure test.

VII. USE OF NDE FOR CRITICAL DEFECT DETECTION ON DIRECT EXAM OF SHORT SEGMENTS

NDE methods used for direct examinations in the ditch can be better than methods used in ILI tools. Because NDE in the ditch is not limited by the environment of in-line inspection, more detailed measurement are can be made. NDE is routinely used in modern pipe mills to detect seam flaws before they can fail during hydrotest in the pipe mill manufacturing process. NDE is also required during in-ditch examination of ILI anomalies to verify the accuracy of an ILI tool. For corrosion metal loss inspections these methods commonly include pit gauges or laser scans for external corrosion, and UT wall thickness measurements for internal corrosion. Methods used to inspect the pipe body for cracking include magnetic particle (MT) crack detection and UT angle beam shear wave measurements. Measurements used to examine the seam or girth welds include MT crack detection, UT angle beam shear waves and radiography (RT). In general MT is used to locate cracks, where UT and RT are used for determining the depth or extent of cracking. Because these methods are used to verify the location of and the sizing accuracy of ILI tools and serve as local reference standards, they are generally considered more accurate than the NDE measurement made from ILI tools.

If these methods are used to certify a piece of pipe, the entire joint (or pup) should be inspected including the girth welds, and any measurements should be recorded in a manner that an independent interpretation of the measurements can be made. This includes photographs of MT, films or digital recording of RT, and reproducible digital recordings of any UT waveforms and a traceable method of locating where the measurement was taken on the inspected pipe.

If measurements from certified personnel are taken and recorded then NDE could serve as the sole assessment technique for short segments where the entire pipe can be excavated for examination, or is already above ground. The chosen NDE method need not be limited to the ones described here but should be repeatable, verifiable, and appropriate for the flaw type of concern. Multiple measurements that can inspect the various portions of the pipe may be needed (such as magnetic particle to detect cracks and angle beam UT to size them) and redundant measurements can help ensure no defect is left undetected.

Table 1, Comparison of pressure testing, ILI, and in-ditch NDE assessment techniques

Assessment Technique	Benefits	Limitations
Hydrotesting	• Appropriate for wide range of defect types and conditions • Known margin of safety for a given test pressure	• Line must be taken out of service • Does not yield information about defect that do not fail during test (not effective for small defects) • Water acquisition, disposal, and any remnant water inside the pipeline can be a problem
In-Line Inspection	• As effective as hydrotest for detecting large defects • Can detect small defects and size all defects allowing planned remediation (immediate response for defects near failure, scheduled response for larger defects, and monitoring for smaller defects • Line does not have to be taken out of service	• Line must be “piggable” • Many anomaly digs may be necessary • Different ILI measurements are required for different defect types, which may necessitate multiple ILI runs • Measurement error must be accounted for (the smallest defects may not be detected and measurement uncertainty must be accounted for requiring additional digs to ensure safety)
In-ditch Non-Destructive Evaluation	• More accurate than ILI (i.e. used to validate ILI measurements) • Line does not have to be taken out of service	• Line must be exposed • Only practical over limited lengths of pipeline • Can be operator skill dependent (recommend recording actual signals for independent verification if needed)

CHAPTER 8

MANAGING CUSTOMER IMPACT

AND ACCELERATED MILES

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PREPARED REBUTTAL TESTIMONY

OF RICK PHILLIPS

I. INTRODUCTION

The purpose of this testimony is to respond to the prepared direct testimony of the Division of Ratepayer Advocates (DRA), Southern California Generation Coalition (SCGC), The Utility Reform Network (TURN), and the Southern California Indicated Producers and Watson Cogeneration Company (SCIP/Watson) filed on June 19, 2012. Specifically, this testimony responds to the following statements and concerns raised by DRA, TURN, SCGC and SCIP/Watson:

A. The Commission needs a more detailed understanding of the reasoning for selecting replacement over pressure testing in order to approve ratepayer funding of replacement activities.

B. The Commission should review each replacement project separately.

C. Only pressure testing should be pursued because it is a lower cost option when compared to replacement.

D. A 6-month notice should be required when service to customers will be curtailed.

E. There is not adequate support or justification in the SoCalGas and SDG&E PSEP filing for the inclusion of the accelerated mileage.

F. PSEP mileage should not be accelerated into Phase 1A because it will result in lower priority segments being addressed before high priority segments

G. Category 1 and 2 segments should not be included in the PSEP or accelerated into Phase 1A.

H. Clarification regarding total Accelerated mileage in the Phase 1A scope.

I. PSEP Phase 1A scope should not include Department of Transportation (DOT) defined distribution mileage

The Commission directives to SoCalGas and SDG&E were to develop plans that "should provide for testing or replacing all [segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test] as soon as practicable"[1] and that address "all natural gas transmission pipeline… even low priority segments,"[2] all the while "[o]btaining the greatest amount of safety value, i.e., reducing safety risk, for ratepayer expenditures."[3] The Plan proposed by SoCalGas and SDG&E strives to achieve each of these goals while also adhering to the guiding principle of minimizing impacts to customers.

In their testimonies, intervenors challenge various elements of the SoCalGas and SDG&E PSEP scope. They make several assertions and recommendations regarding not only the type of work proposed (pressure testing or replacement), but also the boundaries and extents of the different projects (Category 4 criteria miles and Accelerated miles). Such recommendations appear to be primarily based on reducing the cost of Phase 1A of the PSEP with little apparent regard for overall Plan costs or impacts on customers. SoCalGas and SDG&E's Plan minimizes overall costs and impacts to customers.

At the heart of their testimony, DRA, TURN and SCGC would prefer SoCalGas and SDG&E to pressure test, rather than replace, pipelines because they believe that it is the lower cost option. These intervening parties fail to recognize, however, the impracticality of testing some lines, the burden that testing imposes on customers when they have no service for extended periods of time, and the improvement in quality of the pipeline asset.

[1] Decision 11-06-017 June 9, 2011, page 19.
[2] *Id*, page 20.
[3] *Id*, page 22.

Intervenors' myopic focus on costs ignores SoCalGas and SDG&E's mandate to provide safe and reliable service to their customers. SoCalGas and SDG&E take seriously both mandates. In developing their Pipeline Safety Enhancement Plan, they sought to develop a plan that minimizes impacts to their customers. Accordingly, SoCalGas and SDG&E, when implementing Pipeline Safety Enhancement Projects, propose to pressure test pipelines where customer impacts are manageable. Manageable Customer Impacts means that SoCalGas and SDG&E: (1) will not interrupt service to its core customers in order to pressure test a pipeline; (2) will work with Non-Core customers to determine if an extended outage is possible; (3) will, where necessary, interrupt Non-Core customers for short periods of time as provided for in their tariffs; and (4) will – as is their current practice – work with Non-Core customers to plan, where possible, service interruptions during scheduled maintenance, down time or off peak seasons.

SoCalGas and SDG&E will also use alternatives where possible to maintain service to customers during pipeline outages. Such alternatives may include CNG, LNG, temporary bypasses, or alternate feeds from existing pipelines. This, however, does not mean that SoCalGas and SDG&E will use these alternatives where the cost of doing so is outweighed by the benefits gained from replacing the pipeline.

With these principles in mind, SoCalGas and SDG&E have developed a "Replacement Decision Tree." SoCalGas and SDG&E recognize that this decision tree still allows for considerable flexibility. But at this early stage, it is unwise to create an overly prescriptive approach to the decision to test or replace a pipeline segment or to disqualify accelerated pipe segments. Accordingly, SoCalGas and SDG&E also propose to create an "Engineering Advisory Board" to review test versus replace and accelerated mileage decisions until sufficient experience has been gained to allow for the creation of a more systematic approach. Such an advisory board will avoid the cumbersome and time consuming process of having to file an expedited application, as SCGC suggests, for each proposed replacement project.

SoCalGas and SDG&E have proposed in Phase 1A of the PSEP to include lower priority segments or portions of segments in order to achieve overall project and program efficiency and cost effectiveness. The vast majority of these miles would otherwise need to be addressed in a later phase of the PSEP, and are aptly referred to as Accelerated miles due to their advancement from Phase 2 of the Program to Phase 1A. DRA fails to give proper consideration to the interspersed nature of the accelerated pipe segments with Category 4 Criteria pipe segments and has rejected the inclusion of these accelerated miles with seemingly no regard for the impact this would have on total cost, schedule, and customers, and instead recommends that only Category 4 Criteria miles be approved by the Commission for the Phase 1A scope. SoCalGas and SDG&E disagree with DRA's approach. While the Commission directives do state that the Plans "should start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority for pressure testing,"[4] adhering strictly to this approach would not accomplish another Commission goal of having the California utilities complete this work as soon as practicable and in a cost effective manner.

Developing a plan, such as the one put forth by SoCalGas and SDG&E, that attempts to strike a balance between completing the pressure testing and replacement activities as soon as practicable and addressing segments or portions of segments in order of priority (per NTSB criteria and internal subprioritization) is much more in alignment with the overall Commission directives than DRA's approach of deferring all Accelerated miles to a later phase.

[4] Decision 11-06-017 June 9, 2011, page 20.

II. DESPITE STATEMENTS TO THE CONTRARY, CONSIDERABLE EXPERTISE AND JUDGMENT WERE USED WHEN DETERMINING WHETHER TO TEST OR REPLACE A PIPELINE

DRA states in its testimony that SoCalGas and SDG&E's determination to test or replace a pipeline is "too vague and subjective to be relied on by the Commission as the basis of ordering ratepayer funding of hundreds of millions of dollars."[5] Accordingly, DRA recommends that all pipeline segments be pressure tested. DRA is wrong. SoCalGas and SDG&E relied on their judgment based on years of experience and system knowledge to determine which segments of pipe should be tested and which segments should be replaced. And while SoCalGas and SDG&E agree that additional engineering analysis is warranted, they plan to do so. Simply because further review is appropriate, however, is no basis to conclude blindly that all pipeline segments should be pressure tested, as argued by DRA.

SoCalGas and SDG&E used their considerable expertise and judgment when it determined if a segment should be replaced or pressure tested, with over half the miles placed into the pressure test category. The decision to place a pipeline in the replacement category was based on a measured review of the difficulty or impracticality of taking a line out of service. This judgment was made by SoCalGas and SDG&E personnel with years of experience designing and maintaining complicated interconnected piping systems that contain numerous off takes to customers.

Many pipelines simply cannot reasonably accommodate pressure testing because of their configuration and the number of taps off the lines that are used to feed customers. Such

[5] DRA Exhibit 2 Prepared Testimony of D. Phan in A.11-11-002 SoCalGas and SDG&E PSEP, page 48; TURN similarly states that "[i]t is hard to fathom how the Commission can reasonably be expected to pass judgment on the reasonableness of the utilities' proposals and the associated costs when the utilities are not yet in a position to explain how they intend to make the decisions underlying those proposals" (A.11-11-002 TURN Long Testimony, page 4).

pipelines are typically referred to as “distribution supply lines.” As the name implies, these lines are used to supply many customers. While they are operated at greater than 20% SMYS, and therefore are transmission lines under DOT regulations, they – unlike the larger transmission lines used to carry gas long distances - have many interconnections and take off points. Using an analogy: Transmission lines are like freeways – larger capacity with limited off ramps. Distribution supply lines are more like arterial boulevards with many off ramps feeding neighborhoods and commercial businesses lining the boulevard. A consequence of the multiple take off points for these distribution supply lines is that it is much more complicated to feed the many customers with alternate means.

Distribution supply lines are also typically comprised of more than one pipe diameter (e.g. 8”, 10”, 12”). This is a legacy of their age and changes that were implemented over the life of the pipeline (e.g., replacements of pipe sections in an active corrosion zone; the widening of a freeway or road that necessitated the relocation of the line; or a new substructure crossing the line transversely). These lines also contain many features (reduced size valves, pressure control fittings, etc.) that need to be removed prior to testing. Different sizes of pipe make executing a pressure test with water very difficult or impossible. This is because “pigging” is needed in the pressure test process, first in order to remove any air that would otherwise create an air void and influence the test reading, and then to remove water that can otherwise lead to internal corrosion or reach a customer’s meter, causing an outage. The pig device is used to separate liquid from gas and is usually an inflatable neoprene ball or dense foam device. These pigs are able to accommodate one or possibly two pipeline diameters. Accordingly, pipelines with multiple diameters would require multiple hydrotests, increasing costs and creating execution challenges.

III. INTERVENORS WOULD HAVE THE COMMISSION IGNORE THE REAL CUSTOMER IMPACTS THAT WILL OCCUR AS A RESULT OF PRESSURE TESTING PIPELINES THAT ARE ALREADY IN-SERVICE

In their recommendations, intervenors appear to have given little or no regard to the impracticality of testing certain lines or to customers being without gas service for extended periods of time. For example, they are silent about the significant difference in time that customers will be without service for pressure testing when compared to replacement. Unlike replacing a pipeline segment, pressure testing an in-service pipeline can cause service outages anywhere from two to several weeks. In addition it is important to understand that while there is little variability in the length of time it takes to tie in a replacement line to the existing system (less than 1 day to 2 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. SoCalGas and SDG&E have taken these realities into consideration when evaluating manageable customer impacts.

As stated, SoCalGas and SDG&E have done considerable work to determine those segments of pipeline that should be tested and which segments need to be replaced. But SoCalGas and SDG&E recognize that more work still needs to be done. Accordingly, they have developed the following "Replacement Decision Tree" shown in Figure 1 to assist in the decisions to be made under SoCalGas and SDG&E's original decision tree shown in Figure 2. The highlighted branches of the original Decision Tree refer to the greater detail provided by the "Replacement Decision Tree."

Figure 1 – Replacement Decision Tree

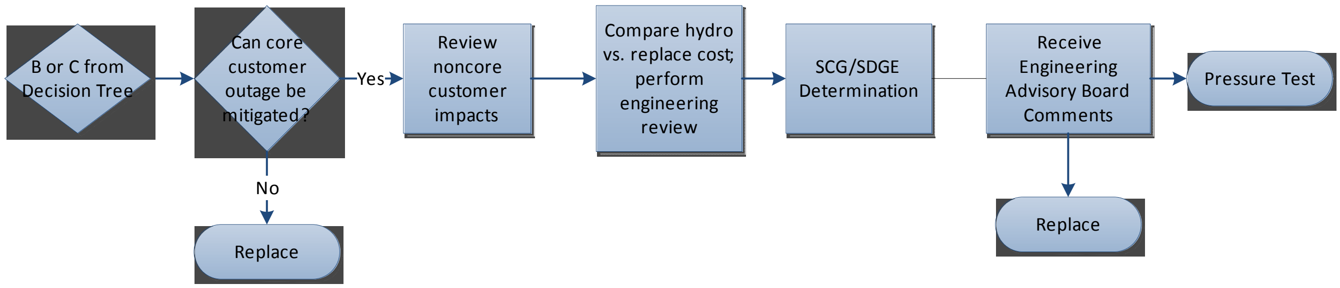
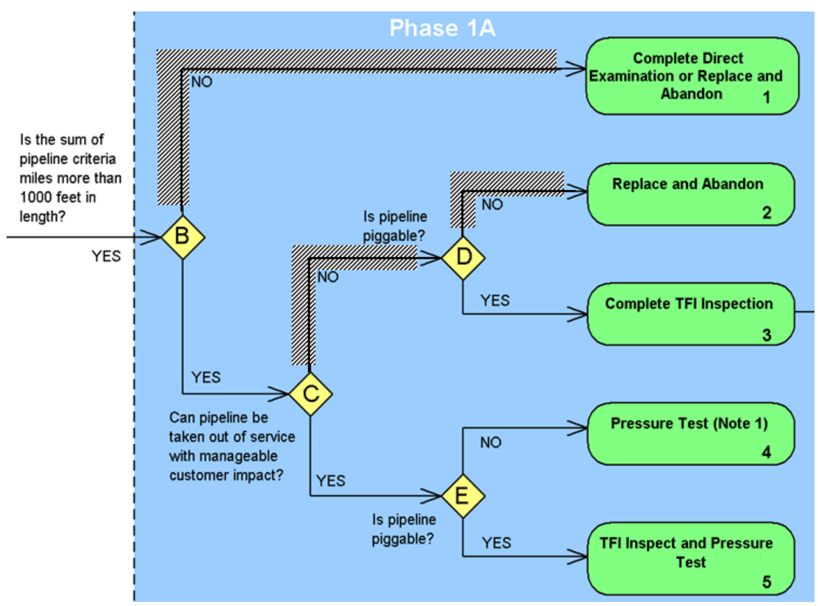


Figure 2 – SoCalGas and SDG&E Decision Tree



SoCalGas and SDG&E's "Replacement Decision Tree" should provide the Commission comfort that the appropriate factors that meet all the Commission objectives will be considered when assessing the determination of whether to pressure test or replace the lines.

The "Replacement Decision Tree" is based on the following principles: (1) That SoCalGas and SDG&E will not interrupt service to its core customers in order to pressure test a pipeline; (2) That SoCalGas and SDG&E will work with noncore customers to determine if an extended outage is possible; (3) That SoCalGas and SDG&E will, where necessary, temporarily interrupt non-core customers as provided for in their tariffs; (4) That SoCalGas and SDG&E will work with non-core customers to plan, where possible, service interruptions during schedule maintenance, down time or off peak seasons, and (5) That SoCalGas and SDG&E will consider cost and engineering factors for the improvement of the pipeline asset.

A. Mitigating Customer Impacts

The evaluation process will start with a determination of whether taking a pipeline out of service for pressure testing would result in the loss of gas service to customers. If service would be interrupted, alternatives to maintaining service to customers during pipeline outages will be evaluated. As part of the planning for the pressure test, SoCalGas and SDG&E will determine whether there is a viable alternative method of providing gas service to impacted core customers (i.e. CNG, LNG, temporary bypass, etc.). If there is not, a replacement line will be installed and the original asset will be abandoned or pressure tested once the new pipeline is in service.

As explained in Mr. Morrow's testimony, SoCalGas and SDG&E will make every effort to minimize impacts to customers by working with them to determine if an extended outage is acceptable or if the outage can be planned around the customer's scheduled maintenance, down time or during off peak seasons.[6]

B. Engineering Review to Align with Integrity Goals

Intervenors highlight the relative difference in the unit cost of pressure testing versus replacement activities as an important reason to either reject or discourage inclusion of pipe replacement in the Phase 1A scope. However, it is important to note that simply applying a pressure test unit cost to a project mileage can result in the omission of potentially significant project costs to manage customer impacts and disregards the opportunity to lower future costs and risks by improving the quality of the pipeline asset.

[6] Reference discussion in SoCalGas and SDG&E Amended PSEP testimony, Section II.A.3.

The estimated costs for hydrotesting provided in the SoCalGas and SDG&E PSEP do not include costs for managing customer impacts, as the pipeline segments selected for pressure testing are assumed to not require extraordinary efforts to maintain service to customers during pipeline outages. While TURN presumes that the "vast differential in the per-unit costs associated with the two options makes pressure testing the less financially consequential of the two,"[7] it is certainly feasible that the costs to manage customer impacts will be significant and cost prohibitive. Indeed, hydrotest costs are expected to be higher than those that appear to have been assumed by intervenors, as explained in SoCalGas and SDG&E witness Buczkowski's testimony. PG&E's experience has shown costs to be higher than originally planned.

Moreover, as a prudent operator, SoCalGas and SDG&E may identify situations in which spending incremental dollars to replace a pipe segment today will pre-empt asking for further funds in a future regulatory proceeding to make a line piggable, add capacity, or replace sections of a pipeline that qualifies for replacement due to leakage history. New lines can have structural advantages compared to earlier vintage lines that improve the overall quality and life of the pipeline asset. Accordingly, SoCalGas and SDG&E have included within their "Replacement Decision Tree" a process that will compare the costs of pressure testing against the costs of replacing an old pipeline if pressure testing appears feasible.

During the detailed engineering process, SoCalGas and SDG&E will consider all costs associated with pressure testing, including managing customer impacts (through CNG, LNG, installing temporary bypasses, etc.). Those costs will be compared with the costs of replacing the old pipeline with a new one. Other engineering factors will also be considered depending on the situation of each unique pipeline. Examples include relocation of the pipeline if it is known

[7] A.11-11-002 TURN Long Testimony, page 11.

that it will need to be moved in the future, and burying the pipeline deeper to reduce the possibility of outside damage.

SoCalGas and SDG&E believe there are cases where a new line is superior in integrity to an older hydrotested line, and therefore disagree with SCGC's statement that "[p]ressure-testing pipelines and replacing pipelines are equally effective in assuring customers that pipelines are safe."[8] As described by Mr. Schneider in Chapter IV of the Amended PSEP testimony, pressure testing does little to prove the integrity of legacy girth welds and other construction threats.[9] New lines can also be made piggable, enhancing future ability to assess the line's integrity.

An assumption used in the development of the proposed scope and cost estimates was that pipelines with less than 1,000 feet being addressed in the PSEP would bypass the customer impact evaluation and automatically be considered replacement projects. The justification for this step is that short sections are usually off takes that feed a regulator station and therefore the longer impacts associated with hydrotests would be unacceptable. Also factoring into the proposed policy is that the cost to hydrotest short distances of pipe are likely to approach or exceed the cost of replacement. While SoCalGas and SDG&E do not agree with DRA's recommended default position to "[i]nstead…pressure test these segments,"[10] as this position is also not adequately supported, SoCalGas and SDG&E will follow the customer impact and economic analysis proposed in this testimony. In doing so, there can be confidence that every project will have thorough justification for the action chosen.

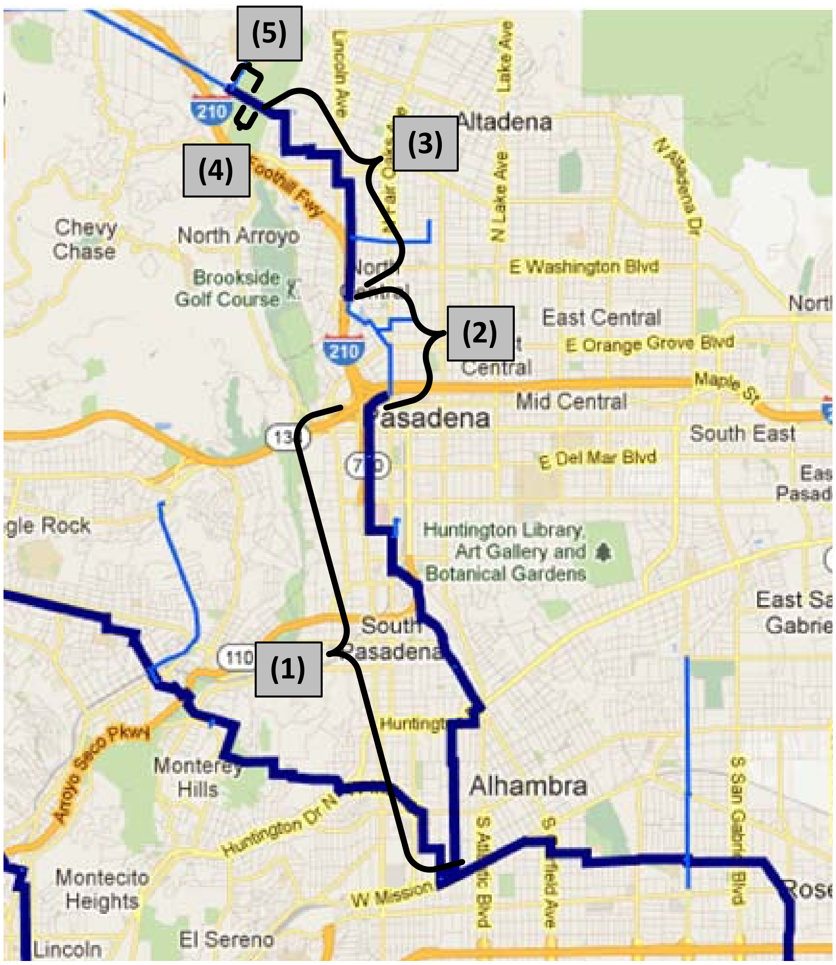
For those 1,000 foot or less projects that, after further evaluation, remain as replacement projects, SoCalGas and SDG&E still propose the Commission authorize the use of direct

[8] A.11-11-002 SCGC Phase 1 CEYap Testimony, page 4.
[9] See discussion in Amended PSEP Testimony beginning in Section IV.B.2.
[10] DRA Exhibit 2 Prepared Testimony of D. Phan in A.11-11-002 SoCalGas and SDG&E PSEP, page 48.

examination in lieu of pressure testing or replacement in order to potentially reduce costs and customer impacts.

The following is an example that illustrates the project execution aspects and challenges and the type of analysis that will be considered in the pressure test versus replace process. Line 32-21 (see Figure 3 below) runs mostly in city streets in the Pasadena area. The primary line was installed in the late 1940's and early 1950's.

Figure 3



For most of the line segments that make up this pipeline there are no records of a pressure test, thus rendering them Category 4. The following describes the sections identified in the figure:

(1) Entirely Category 4 criteria mileage except for a 20 foot segment at the beginning of the line that meets the DOT definition of a distribution line. The pipe segments were installed in the late 1940's and early 1950's. This section contains 12", 16", and 20" pipe and changes from one to another 7 times. Hydrotesting may well require a minimum of seven different test segments and possibly more to avoid customer impacts.

(2) Primarily contains a pipe relocation done in the early 1970's due to a freeway widening effort. These pipe segments are Category 1 per the definitions provided in Chapter IV of the SoCalGas and SDG&E PSEP testimony. This section is comprised of 2 different pipe diameters. This section also contains a small amount of pipe meeting the definition of a DOT Distribution line, and also is comprised of 2 different pipe diameters.

(3) Entirely Category 4 criteria mileage installed originally in the late 1940's. There is one diameter change over this section from 20" to 12", which would prohibit hydrotesting the entire section with a single test.

(4) Short section of Category 4 non-criteria mileage. This is a Class 1 area where the pipeline crosses the Arroyo Grande (north of the Rose Bowl). Under DRA's proposal this section would not qualify for accelerated treatment in Phase 1A, thus creating the need to re-visit this pipeline in a later Phase of the PSEP. (Accelerated pipe will be discussed in more detail further in this testimony)

(5) Short section of Category 4 criteria mileage installed originally in the late 1940's.

This example is provided to highlight the issues that would be factored into a cost estimate for hydrotesting. First, customer impacts would be assessed. If necessary, costs to provide alternate means of service during the time that each section was out of service would be calculated. Next, the number of test sections would be determined. Under DRA's proposal to only hydrotest Category 4 criteria pipe in Phase 1A, there would be up to 10 separate pressure test sections, with the possibility of more if elevation changes or mitigation of customer impacts requires further segmenting of the pressure test. Costs to prepare each of the 10 hydrotest sections would be calculated. The pipeline would then have to be revisited (contractors re-mobilized, permits applied for again, customers possibly impacted a second time) in Phase 2 for one additional pressure test.

Further engineering review would take into consideration the age and condition of the late 1940's and early 1950's pipe that would still remains in the system.

After all factors are gathered, SoCalGas and SDG&E engineers will propose replacement or pressure test. It may be that certain sections of a pipeline will be planned for replacement and other sections planned for test. The proposed action will then be offered to the Engineering Advisory Board for input. This Board is described in the next section.

IV. SOCALGAS AND SDG&E PROPOSE AN ENGINEERING ADVISORY BOARD TO REVIEW WHETHER A PIPELINE SHOULD BE TESTED OR REPLACED

SoCalGas and SDG&E have described the many factors that determine proper test or replace action. SoCalGas and SDG&E have also described that the decision to test or replace different pipelines embodied in its filed Plan was based on its considerable expertise and knowledge of its system. Intervenors have called into question SoCalGas and SDG&E's decisions. SoCalGas and SDG&E propose the formation of an Engineering Advisory Board to provide an extra level of comfort that their decisions have been sound. Because it would be premature at this early state to create a prescriptive approach to the determination of whether to test or replace a pipeline, SoCalGas and SDG&E recommend that the Commission adopt its proposal to create an Engineering Advisory Board to review its decisions to test or replace a pipeline to confirm that SoCalGas and SDG&E's decisions are based on sound customer, economic, and engineering evaluation.

This Engineering Advisory Board would be a four member board made up of a company representative, a representative of the CPUC's Consumer Protection and Safety Division (CPSD), a representative of the CPUC's Energy Division, and an outside pipeline integrity expert to be mutually agreed upon by the first three. This advisory board will review and provide input on SoCalGas and SDG&E's test or replace decisions and its accelerated mileage decisions. It will also provide input to SoCalGas and SDG&E's occasionally updated test/replace/accelerate criteria to reflect the experience gained over time.

It is important that the Board be structured to not impede the aggressive schedule of Phase 1A. Boards with a large number of members can take longer to reach decisions. Therefore, SoCalGas and SDG&E propose the membership be limited to the four positions listed. Also, since the Board will be reviewing primarily cost and engineering related issues it is important that its members be experienced in pipeline integrity engineering issues.

As SoCalGas and SDG&E ramp up and review each pipeline segment for its unique issues, experience will be gained with customer impacts, hydrotest and replacement costs, and the various engineering aspects. Through this knowledge a better refinement of the instances when it makes sense to replace versus test, and when to accelerate segments from later phases to Phase 1A will be known. It is expected that the Board will be more active at the beginning as each segment is reviewed with a tapering off of the number of decisions to be reviewed as information is gained over time. SoCalGas and SDG&E anticipate being able to absolve the Board in connection with the next GRC decision. The Boards function will be reviewed annually as to its appropriate level of involvement.

This Engineering Advisory Board proposal is superior to the process suggested by SCGC. As stated in Mr. Ed Reyes' testimony, requiring SoCalGas and SDG&E to submit an application (even if expedited) for every replace or test decision will create an unnecessary bureaucratic and cumbersome layer, slowing down progress on an already ambitious schedule, and ultimately preventing pipeline segments from being addressed "as soon as practicable."[11] SCGC's proposal to file an expedited application for each proposed replacement project should be rejected.

V. THERE IS NO MERIT TO SCIP/WATSON'S RECOMMENDATION THAT A 6-MONTH NOTICE SHOULD BE REQUIRED WHEN SERVICE MUST BE CURTAILED

SCIP/Watson assert "when service must be completely curtailed, SoCalGas / SDG&E should be required to provide customers operating critical energy infrastructure with at least 6 months' notice to allow the safe wind down of operations."[12] As previously stated, minimizing customer impacts is one of the foundational elements of the proposed PSEP. In direct testimony, SoCalGas and SDG&E provided examples of practices they engage in to minimize customer impacts, and would continue to pursue throughout execution of the PSEP, include making "every attempt to work around customer schedules (e.g., planned outages for maintenance and construction) as much as possible."[13] While it would be ideal to give customers notice of pipeline outages in a manner consistent with what SCIP/Watson recommend, the ambitious schedule proposed for the PSEP may not always allow for such extensive notification. With the amount of projects that need to be executed in Phase 1A, after allowing for detailed engineering, design, and execution planning, there may not be sufficient time to afford six-month notice

[11] Decision 11-06-017 June 9, 2011, page 19.
[12] SCIP-Watson Testimony (Beach) at p. 4.
[13] Reference discussion in SoCalGas/SDG&E Amended PSEP testimony, Section II.A.3.

before field work and any ensuing customer outages need to commence. SoCalGas and SDG&E recognize the importance of providing reliable service and will work to provide as much notice as feasible to impacted noncore customers should an interruption be necessary.

VI. SOCALGAS AND SDG&E'S INCLUSION OF ACCELERATED MILEAGE IN THE PSEP IS MOTIVATED BY A DESIRE TO MINIMIZE CUSTOMER IMPACTS, ACHIEVE COST EFFECTIVENESS, AND ADDRESS PIPELINE SEGMENTS LACKING DOCUMENTATION OF A PRESSURE TEST AS SOON AS PRACTICABLE

Both DRA and TURN express an opinion that insufficient analysis and justification was presented to support inclusion of Accelerated miles in Phase 1A. Though SoCalGas and SDG&E did not perform specific studies prior to filing it's PSEP to illustrate economic and project efficiencies resulting from accelerating these miles, the selection of the accelerated miles was done -- as were the decisions made for pressure test or replacement described earlier in this testimony -- based on expertise and engineering judgments by subject matter experts who are knowledgeable about our system. The extensive knowledge that company subject matter experts possess were used to select segments to accelerate into the Phase 1A scope and represents an intent to achieve the overarching goals of the PSEP[14]. To characterize the accelerated mileage scope as "included primarily to inflate the costs of the Plan"[15] or determined through "no analysis beyond asking a few field personnel what they felt about the proposal"[16] is to unjustifiably diminish the judgment of SoCalGas and SDG&E's subject matter experts.

SoCalGas and SDG&E did communicate examples of the types of situations considered when determining the Accelerated mileage scope, including:

[14] SoCalGas/SDG&E Amended Testimony, Section II.A.
[15] DRA Exhibit 2 Prepared Testimony of D. Phan in A.11-11-002 SoCalGas and SDG&E PSEP, page 12.
[16] A.11-11-002 TURN Marcus testimony, page 20.

- If a Category 4 segment containing Criteria mileage and proposed to be replaced or pressure tested in Phase 1A also has Non-Criteria portions, then the Non-Criteria portions are included in the replacement or pressure test scope.
- A Phase 2 segment (or segments) located between two Phase 1A segments or immediately adjacent to a Phase 1A segment may be "accelerated" into the Phase 1A scope if it is anticipated that the incremental cost and impact of continuing the replacement or pressure test to include the Phase 2 segment(s) would overall be more efficient and cost effective than interrupting the effort in Phase 1A and returning to the same location again in Phase 2.
- If it is anticipated that replacement of pipe segments in their existing location is infeasible (due to the presence of other underground utilities, not enough space in the Right-of-Way, etc.). In such circumstances, in order to replace the Phase 1A portions, a re-route of the pipeline may be required. Continuing the replacement of the pipeline along the new route to effectively replace some Phase 2 (accelerated) segments in Phase 1A may be more efficient from a cost and operations perspective than tying back and forth between the new route and the original pipeline.[17]

Subsequent to the filing, SoCalGas and SD&E studied in more detail a select number of projects with Accelerated mileage in the Phase 1A scope. In response to a data request[18], five projects (two pressure tests and three replacements) in the PSEP filing were examined to understand the effect on total cost of deferring the Accelerated mileage portion of the as-filed Phase 1A scope to Phase 2. This effort assumed all Accelerated miles would need to be addressed in Phase 2 and utilized a cost estimate methodology consistent with that presented in

[17] DRA-DAO-19-1(b).
[18] SCGC-10.4.

the filing and workpapers. For the replacement projects, by deferring the Accelerated mileage to Phase 2, the overall direct cost for the as-filed scope of work is estimated to increase by approximately 3.5 – 8.0%. For the pressure test projects, the increase in overall direct cost resulting from the deferral of Accelerated mileage to Phase 2 is estimated to be higher, in the range of 30 - 200%. This does not consider the customer and community impacts and risks associated with an approach to test or replace strictly Category 4 criteria segments which would result in many more test sections.

While only a small sample of projects were evaluated in greater detail as part of this effort, the fact that each one indicated an overall cost increase by deferring part of the scope to a later time suggests a pattern that is likely representative of many other pipeline s in the PSEP.

VII. ACCELERATED MILES WILL BE EVALUATED FURTHER IN THE ENGINEERING, DESIGN, AND EXECUTION PLANNING PHASE OF A PROJECT AND WILL BE OFFERED FOR REVIEW BY THE ENGINEERING ADVISORY BOARD

As each pipeline is reviewed in greater detail certain mileage proposed to be accelerated into Phase 1A may ultimately be deferred to a later phase, while other segments or portions of segments that were not proposed to be accelerated may be deemed more cost effective to include in the Phase 1A scope.

Keeping the Commission informed of the scope of PSEP projects through the annual status report proposed in the PSEP filing[19] should instill the necessary confidence that SoCalGas and SDG&E are being prudent in their project definition and focusing on the best interest of the ratepayers from a safety and cost perspective. Furthermore, the Engineering Advisory Board, which will review and help define the decision process to pressure test or replace a pipeline

[19] SoCalGas/SDG&E Amended PSEP testimony, p. 6.

segment, will be asked to also provide a similar assessment of the validity and appropriateness of including accelerated miles in the Phase 1A scope. The Board will review the decision process for determining mileage to accelerate into Phase 1A to see that it is repeatable, consistent with established guidelines, and is periodically updated to reflect lessons learned and knowledge gained as projects are executed.

VIII. AN ACCURATE INTERPRETATION OF THE COMMISSION DIRECTIVES WILL CONFIRM THAT SOCALGAS AND SDG&E ARE NOT ERRONEOUSLY INCLUDING MILEAGE IN THE PSEP SCOPE

DRA expresses concern that “SoCalGas and SDG&E are erroneously including segments that have previously been tested, and met the elements required by the regulations in effect, in the scope for Phase 2 and then accelerating these segments into Phase 1A as part of its Accelerated Miles”[20]

This statement is reference to the relatively small amount of Category 1 and 2 segments that were also included in the Phase 1A scope. The primary motivation for their addition to the scope is to facilitate project continuity and overall cost effectiveness. In these cases it is anticipated that executing the project to exclude these segments would be costlier than including them in the scope.

There is also a secondary motivation for pre-1970 segments because even though documentation exists for a pressure test demonstrating a safe operating margin of 1.25 times MAOP, these segments will still need to be re-tested or replaced in order to be brought into accordance with current standards. As Mr. Schneider explains in his rebuttal testimony DRA[21]

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[20] DRA Testimony (Phan) at p. 10.
[21] DRA asserts that “D.11-06-017 does not require the digging up and testing to Subpart J those pipeline segments that have been previously tested” (DRA Exhibit 2 Prepared Testimony of D. Phan in A.11-11-002 SoCalGas and SDG&E PSEP, page 10).

ignores ordering Paragraph 4, which states that "all in-service natural gas transmission pipeline in California [be] pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)."[22]

As such, Phase 2 of the PSEP needs to include not only Category 4 segments located in less populated (Class 1 and 2 non-HCA) areas, but also Category 1 and 2 segments that do not have pressure test records in accordance with modern standards. Consistent then with the approach outlined thus far, if SoCalGas and SDG&E identify a scenario in which accelerating these Category 1 or 2 segments that would otherwise be addressed in Phase 2 into Phase 1A would result in economic or operational efficiencies, then doing so should be considered reasonable and appropriate.

IX. SOCALGAS AND SDG&E OFFER CLARIFICATION TO THE NUMBER OF MILES PROPOSED TO BE ACCELERATED IN THE THEIR PLAN

Most of the intervenors' testimony commented on the amount of mileage proposed to be accelerated into Phase 1A of the PSEP. It should be clarified that new pipe construction was included in the Accelerated mileage total. New pipe construction is associated with the Line 6914 extension and the Line 1600 replacement and accounts for 15 SoCalGas Transmission, 13 SoCalGas Distribution, and 54 SDG&E Transmission Accelerated miles. These totals have an effect of skewing the Accelerated mileage total to appear to be a larger percentage of the total replacement miles. Excluding these miles leaves approximately 90 Accelerated miles for SoCalGas replacements to 128 Category 4 criteria, and 21 Accelerated miles for SDG&E replacements to 28 Category 4 criteria. As a point of reference, PG&E pressure tested approximately 163[23] miles in 2011 as part of their PSEP program. Approximately 100[24] of these

[22] Decision 11-06-017 June 9, 2011, page 20.
[23] PG&E Rebuttal Testimony, page 4-2.

miles were high priority, leaving about 60 Accelerated miles, even after detailed engineering and execution planning.

X. DOT DEFINED DISTRIBUTION MILEAGE INCLUDED IN THE PHASE 1A SCOPE SHOULD REMAIN IN THE PLAN

In their testimony, DRA recommends the Commission "reject the inclusion of 28 miles of distribution pipelines from the Plan because these pipelines would be more appropriately addressed as part of SoCalGas' and SDG&E's Distribution Integrity Management Program (DIMP) or with its next GRC"[25]

As explained in the supplemental direct testimony[26] submitted June 4th, 2012, the SoCalGas and SDG&E PSEP scope does propose to pressure test or replace a relatively small amount of mileage defined as DOT Distribution. These segments are included because of the perceived cost and operational efficiencies gained by incorporating them into the scope rather than executing a project around them. Inclusion of these segments is not driven by the presence of integrity threats that would otherwise need to be addressed in the Distribution Integrity Management Program. Per the aforementioned supplemental direct testimony, upon completion of detailed engineering, design, and execution planning, "determination with respect to the potential testing or replacement of each distribution segment identified above will be completed, and testing or replacement of each of a particular segment in Phase 1A will only be performed if including it within the scope of work is projected to be more cost effective than excluding it."[27]

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[24] PG&E presentation *Hydrotesting Challenges*, presented May 2, 2012, p. 4; presentation references PG&E's completion in 2011 of 102.3 Priority 1 Miles and 163.6 Total Miles.

[25] DRA Exhibit 2 Prepared Testimony of D. Phan in A.11-11-002 SoCalGas and SDG&E PSEP, page 18.

[26] PREPARED SUPPLEMENTAL DIRECT TESTIMONY OF DOUGLAS M. SCHNEIDER AND DAVID L. BUCZKOWSKI IN SUPPORT OF THE PIPELINE SAFETY ENHANCEMENT PLAN OF SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY, June 4th, 2012.

[27] *Id*, page 4.

And, as discussed above, the determination to ultimately include these pipelines in Phase 1A would be reviewed by SoCalGas and SDG&E's proposed Engineering Advisory Board.

XI. CONCLUSION

SoCalGas and SDG&E were ordered in their PSEP Plan to "set forth the criteria on which pipeline segments were identified for replacement instead of pressure testing." To satisfy this requirement and to determine a work scope to serve as the basis for the project cost estimates, SoCalGas and SDG&E have proposed that pressure testing will be completed on pipeline segments that can be taken out of service with manageable customer impacts.

In order to provide further clarity, SoCalGas and SDG&E offer additional guidelines that will be considered in the decision process for determining when pressure testing and replacement will be used during execution of the PSEP.

Assuming the guidelines outlined in this testimony are followed, replacement should be considered an appropriate and reasonable option to address segments in the PSEP.

An outright dismissal of the entire accelerated mileage scope is unreasonable and inconsistent with Commission directives to develop plans that "provide for testing or replacing all such pipeline as soon as practicable."[28] Such an approach to the PSEP also disregards one of the overarching Commission goals of "[o]btaining the greatest amount of safety value, i.e., reducing safety risk, for ratepayer expenditures."[29] For the reasons mentioned above, inclusion of accelerated miles in the scope of Phase 1A is reasonable and appropriate.

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[28] Decision 11-06-017 June 9, 2011, page 19.
[29] Decision 11-06-017 June 9, 2011, page 22.

CHAPTER 9

HYDROSTATIC TESTING COSTS, PIPE REPLACEMENT COSTS, AND CONTINGENCY

TABLE OF CONTENTS

PREPARED REBUTTAL TESTIMONY

OF DAVID BUCZKOWSKI

I. INTRODUCTION

The purpose of this testimony is to respond to the prepared direct testimony of Division of Ratepayer Advocates (DRA), Southern California Generation Coalition (SCGC), and The Utility Reform Network (TURN) filed on June 19, 2012. Specifically, my testimony responds to the following statements and concerns raised by DRA, TURN, and SCGC:

A. The cost estimates for pressure testing and pipe replacement included in the PSEP filing are supposedly not reliable;
B. Hydrotest cost estimates included in the PSEP filing are allegedly excessive; and
C. Contingency costs included for the pipe replacement and pressure testing estimates are excessive and should not be more than 8%.

On June 16, 2011, the Commission ordered California natural gas transmission pipeline operators to prepare and submit 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. These plans should provide for testing or replacing all such pipeline [sic] as soon as practicable*."[1] The Commission ordered the California gas utilities to file their "Implementation Plans" (i.e., Pipeline Safety Enhancement plans, or "PSEPs") no later than August 26, 2011. With this order, SoCalGas and SDG&E had just over two months to develop a comprehensive PSEP and to establish reasonable cost projections and timelines that would meet the Commission's mandate.

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

[1] D.11-06-017, mimeo., at 19.

available to develop them. SoCalGas and SDG&E acknowledge that these estimates are necessarily preliminary and often somewhat conceptual in nature. However, these estimates, when combined with the risk-based allowances provided by established contingencies, provide a reasonable projection of costs that will ultimately be incurred by SoCalGas and SDG&E to achieve the Commission's commitment to improve the safety of natural gas transmission pipelines in California.[2]

SoCalGas and SDG&E recognize that cost estimates will necessarily require refinements and updates as more information is compiled and projects are further defined. Further analysis, project definition, and updating of the PSEP cost estimates will be performed during the engineering, design, and execution planning phase of each project. This will ensure that decisions made based on estimated costs, particularly the decision to pressure test or replace, will be based on a greater level of project definition than currently exists. However, by establishing a cost projection based on reasonable Class 5 estimates and associated contingencies, SoCalGas and SDG&E have provided the Commission with a mechanism to allow the expeditious progression of this important program, while maintaining the opportunity to oversee program developments, and to implement our shared vision to improve gas pipeline safety.

The approach set out by SoCalGas/SDG&E is in stark contrast to the recommendations put forward by DRA, TURN and SCGC in their respective testimonies. These intervenors appear to support a "wait and see" approach that would increase bureaucracy and slow down the PSEP execution while SoCalGas and SDG&E further define PSEP projects, provide further assessments of potential safety threats, establish more refined estimates and seek prior approval from the Commission on a project-by-project basis.

[2] *See* D.11-06-017, mimeo., at 16.

SoCalGas and SDG&E appreciate and accept the fact that we must establish a strong governance structure and a transparent control environment to facilitate the Commission's PSEP oversight role and to demonstrate the reasonableness of our PSEP execution efforts. However, considering the difficulties and challenges inherent in testing and/or replacing large portions of a complex natural gas infrastructure system, while maintaining reliable service to customers, SoCalGas and SDG&E believe the recommended "wait and see" approach advocated by DRA, TURN and SCGC would result in delays, inefficiencies, and increased overall costs to customers. This approach is also inconsistent with the Commission's vision to expeditiously improve the safety of natural gas pipelines in California.

II. THE PRELIMINARY PSEP ESTIMATES DEVELOPED BY SOCALGAS AND SDG&E PROVIDE A RELIABLE COST PROJECTION

A. Assumptions and Projections

To achieve the Commission's directives to provide implementation plans that "must include best available expense and capital cost projections,"[3] SoCalGas and SDG&E developed their PSEP based on reasonable assumptions and projections, and established preliminary cost estimates following common industry practices. Specifically, as SoCalGas and SDG&E have stated in data requests and discussions with intervenors, "the replacement and pressure test cost estimates developed for the PSEP filing are Class 5 or slightly better."[4] This estimate class is in reference to the Cost Estimate Classification System developed by AACE International. The AACE system groups cost estimates by the level of project definition that was ultimately achieved for the estimate development. It describes the characteristics, end usages, expected accuracies, etc., of cost estimates as they range from high level to full detailed estimates.

[3] D.11-06-017, mimeo., at 32.
[4] Response of SoCalGas and SDG&E to DRA-DAO-19-2.

According to the AACE recommended practice "[o]nly the level of project definition determines the estimate class."[5] It is then the responsibility of the user to appropriately interpret the function of that estimate. For such strategic planning purposes as project screening or feasibility analyses, project owners will commonly rely on a Class 5. While additional project definition and analysis is typically required to refine the estimates to support a more detailed program budget authorization, the class 5 estimates provide a valuable basis to move forward with a major capital program.

B. Accuracy of the data set used to define the PSEP hydrotest and replacement scope

TURN argues that, based on discrepancies found between the data set provided in response to data request DRA-DAO-16 and the information included in the testimony, that the Commission should require the "Sempra Utilities to update and correct the database for review by the parties"[6]. DRA recommends, based on a similar comparison, that "the Commission require Sempra to explain the differences in the number of pipelines identified in its testimony and workpapers, and the number of miles of pipelines identified in the Decision Tree database, and to provide additional assurance that the Plan's scope is accurate, reliable, and can be validated."[7]

As SoCalGas and SDG&E had explained to both DRA and TURN in our data responses, compilation of the data included in the spreadsheet provided in response to DRA-DAO-16 Question 6 was completed nine months after the filing and in direct response to the data request. We also noted that the data set would contain some discrepancies due to the timing of the creation of the spreadsheet for the data request and the fact that the data set used to define the

[5] AACE International Recommended Practice No. 18R-97, page 2.
[6] TURN Testimony (Long) at p. 18.
[7] DRA Testimony (Phan) at p. 74.

scope of the PSEP projects, including the testimony and workpapers, is not static (e.g. hydrotest records continue to be researched, HCA and class locations change, etc.).

The database created and approach used to define the PSEP hydrotest and replacement scope was reasonable and appropriate to develop an estimate, with the appropriate level of contingency, for the Commission to authorize the PSEP. As indicated in Rick Phillips' testimony, assessment of the technical inputs and scope will be reviewed on a project by project basis by the Engineering Advisory Board. To provide updated mileage numbers and explanations of relatively small discrepancies[8] between the figures in the filing versus those in the spreadsheet provided in response to this DRA data request for additional review, as TURN and DRA recommend, will further the "wait and see" approach that seems to have been adopted by these intervenors.

III. HYDROTEST COST ESTIMATES WERE DEVELOPED BASED ON BEST AVAILABLE INFORMATION AND PROVIDE A REASONABLE PROJECTION OF COSTS THAT WILL BE INCURRED DURING PSEP EXECUTION

DRA takes issue with the hydrotest cost estimates included in the SoCalGas and SDG&E PSEP. Their testimony states that "Sempra's average unit cost per segment of $1.4 million for SoCalGas Transmission pressure testing projects is excessive and without justification."[9] This statement is confusing in that a segment is not a standard length. Because hydrotests have fixed cost components as well as variable costs that depend on testing lengths, referencing a cost per

[8] *See* DRA Testimony (Phan) at p. 74; DRA cites a discrepancy between the Category 4 pressure test miles from the testimony (206 miles) and the workpapers (171.5 miles). However, the 206 miles from the testimony (page 108) includes all SoCalGas as well as the SDG&E Category 4 criteria mileage. The 171.5 mileage figure looks to only include SoCalGas Transmission and SoCalGas Distribution (no SoCalGas Storage or SDG&E miles). Also, DRA cites a discrepancy between the SoCalGas DOT defined transmission mileage identified in Question 2 of the data request response (3757 miles) and the value obtained from the data in Question 6 (3131 miles). The database created in response to Question 6 did not include a large portion of Class 1 and 2 non-HCA (non-Criteria) mileage that is included in the 3757 figure.

[9] DRA Testimony (Phan) at p. 59.

segment without alluding to the segment length makes interpretation of this unit cost difficult. DRA further states that "[a]lthough the average cost per mile gives some indication of how much it would cost to perform hydrostatic testing, the cost of testing a segment is a better indicator of testing costs."[10] However, DRA does not provide any rationale for its apparent position that a per-segment cost estimate is a better indicator than a per-mile cost estimate.

DRA's testimony identifies several specific cost elements (see below) for which they dispute the unit cost included in the SPEC Services estimates. Such unit costs can be debated even on cost estimates with much greater project definition, let alone a Class 5 estimate that utilizes several assumptions and factors that can yield a fairly wide expected accuracy range. As such, SoCalGas and SDG&E do not agree with DRA's recommendation that the Commission adopt "unit rather than aggregate or average hydrotest costs."[11] As SoCalGas and SDG&E further develop and define their PSEP projects, the detail and justification for costs used in our estimates will be far more aligned with the specific project characteristics.

SoCalGas and SDG&E agree with DRA that it would be prudent to develop a water management plan to accompany the hydrotesting program, and we intend to pursue such a plan during the engineering, design, and execution planning. This will provide a framework for realizing efficiencies in the purchase, treatment, and disposal of hydrotest water, as well as any additional water or solutions used to clean a pipeline prior to testing, and will identify opportunities to re-use water for multiple hydrotests, all of which should ultimately yield the best opportunity to minimize project costs.

[10] DRA Testimony (Phan) at p. 59.
[11] DRA Testimony (Roberts) at p. V-30.

A. Water Supply Costs

DRA asserts that "Sempra should be paying approximately $.01 to $.02 per gallon for supply water, not $.45 as used in its Safety Enhancement estimate."[12] However, the $0.01 to $0.02 per gallon value that DRA notes and the $0.45 per gallon value found in the SPEC estimates have different underlying assumptions and cannot undergo a like-to-like comparison. DRA's calculation appears to assume an accessible water hydrant adjacent to the hydrotest segment. While the assumptions listed in Appendix D of our testimony do state that an "[e]stimate assumes on-site water supply will be available for purchase at one end of the pipeline segment," this was not intended to necessarily presume close proximity to a hydrant. As such, the Total Hydrotest Water element in our cost estimate assumes a component for transportation of hydrotest water via truck, as well as additional costs for filling and unloading water from the trucks. The vacuum truck that DRA references is used on-site to facilitate movement of the source water from the transport truck into the pipeline before the test is initiated and from the pipeline into the Baker upon conclusion of the hydrotest, and, as such, is separate from the transportation and filling components included in the Total Hydrotest Water unit cost.

It should be noted that no additional costs were included in our hydrotest estimates for additional water for flushing or other solutions used to clean a pipeline prior to hydrotesting. It has been PG&E's recent experience in their PSEP work that pre-test cleaning has contributed significantly to project costs and is a major reason that the actual costs incurred thus far have been well in excess of the estimated values found in their filing.[13]

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[12] DRA Testimony (Roberts) at p. III-13.
[13] *See* discussion in PG&E's Reply Brief in R.11-02 019 at pp. 43-44.

B. Water Disposal Costs

In their testimony, DRA assumes that storm drains or sewer systems will frequently be an option for hydrotest water disposal. To justify this statement, DRA points to the fact that "Sempra has been cleaning its lines as part of ILI testing, and that only clean water will be used to fill the lines for test."[14] While it is true that pipelines are cleaned prior to pigging, it is also important to note that cleaning is only done to the extent that good contact can be made between the MFL pig and the pipe wall, which is needed for a successful in-line inspection. Most permits to dispose into these types of systems require water quality comparable to drinking water. In the vast majority of cases, the hydrotest effluent water from a pipeline that has been cleaned prior to pigging will still be contaminated beyond the thresholds for disposing into these types of systems. Furthermore, not all pipelines undergo in-line inspection as part of TIMP. ILI is just one of the acceptable assessment methods utilized in TIMP, and many pipelines, particularly the distribution supply lines, have never been in-line inspected or internally cleaned.

On top of the hydrotest cost estimates provided by SPEC Services, SoCalGas and SDG&E included an allowance for post-pressure test repairs. DRA references SoCalGas' and SDG&E's excellent safety performance to contest the appropriateness of this cost, stating that "if there are any repairs needed, the cost will be de minimis."[15] While SoCalGas and SDG&E are proud of our previous safety performance, and maintain confidence in the overall integrity of their pipeline systems, the PSEP pressure testing program will take a significant portion of the SoCalGas and SDG&E system to pressure levels not achieved under normal operations. This may create leaks or ruptures that will need to be repaired before placing pipelines back into service. When pressure tests are actually executed for the PSEP, the quantity of repairs per test

[14] DRA Testimony (Roberts) at p. III-14.
[15] DRA Testimony (Phan) at p. 62.

segment may in fact be less than what we have assumed in our plan. However, it is also possible that actual repairs cost more than the unit cost assumed in the plan as well. The allowance for post-pressure test repairs included in the SoCalGas and SDG&E PSEP represents a forecast of the effort that could be required to repair pressure test failures.

IV. SOCALGAS' AND SDG&E'S APPROACH TO ESTABLISHING THE REQUESTED PSEP CONTINGENCY AMOUNT IS REASONABLE AND APPROPRIATE

DRA suggests the Commission should adopt a contingency percentage for the PSEP estimate of "no more than 8%, which is comparable to amounts the Commission has approved for more complicated projects such as PG&E's, SoCalGas', and SDG&E's Advanced Metering Infrastructure (AMI) projects."[16] DRA's recommendation represents a misunderstanding of the intent and function of a contingency in a project cost estimate and is inconsistent with prior Commission directives related to estimate contingencies. An 8% contingency for the PSEP would significantly understate the required estimate allowance to cover the risk profile associated with this program, and would be materially less than the contingency amounts required for this program following common industry estimating practices. DRA further attempts to justify their position by stating "[w]ith the Plan, Sempra is proposing work activities that are not any different than, and with a similar time frame as, the work activities proposed in a general rate case."[17] This is not accurate. Undertaking a massive program to hydrotest existing lines, or replace lines, as is proposed in our PSEP, is unprecedented. This statement demonstrates a fundamental misunderstanding of the complexity, challenges, and risks of

[16] DRA Testimony (Phan) at p. 64.
[17] DRA Testimony (Phan) at pp. 65-66

executing one of the largest infrastructure projects in the history of our company on an aggressive schedule.

Similarly, TURN's allegation that the requested PSEP contingency amounts are "excessive" is without merit, and ignores common industry practices to establish risk based allowances for capital projects in the early phases of their natural life cycles. The contingency percentages established by the engineering consultant for SoCalGas and SDG&E, SPEC Services, were developed following common industry estimating practices and are consistent with prior Commission directives.

A. SoCalGas and SDG&E's approach to establish the requested PSEP contingency amount is consistent with common industry estimating practices

With respect to the intent and function of a contingency, in a response to a data request, SoCalGas and SDG&E defined contingency as an amount "covering costs that may result from incomplete design, unforeseen and unpredictable conditions, or uncertainties within the defined project scope." This position is consistent with the definition of contingency as defined by the Association for the Advancement of Cost Engineering (AACE):

> Contingency is a cost element of the estimate used to cover the uncertainty and variability associated with a cost estimate, and un-foreseeable elements of cost within the defined project scope. Contingency covers inadequacies in complete project scope definition, estimating methods, and estimating data.[18]

Similarly, the US Department of Energy (DOE) notes that contingency is "*a normal component of a project's costs and is to be included in estimates during the budgeting process, commensurate with project risks*."[19] Therefore, including a contingency in a project estimate does not reflect a "cushion" or a "padding" of the estimate as alleged by DRA, but instead

[18] AACE International Recommended Practice, No. 34-R-05, TCM Framework: 7.3 - Cost Estimating and Budgeting, 2007, p. 4.
[19] US DOE Cost Estimating Guide for Program and Project Management, April, 2004, DOE G 430.1-1X, p. 40.

reflects an essential element of the estimate that provides a risk-based allowance for unforeseeable elements of a defined project scope. Including an appropriate contingency amount that reflects the current stage of project definition and project risk profile allows the estimator to establish a reasonable estimate amount for the ultimate project delivery. It should be noted, however, that contingency specifically excludes changes or additions to the project scope as well as unforeseen major events or outside factors, such as, changes in the regulatory environment, changes or unusual permit requirements, natural disasters, prolonged labor strikes, etc. It is not appropriate to include costs for potential new scope, or extraordinary risk events in contingency as doing so would unduly increase project estimates.

Common estimating practices require an estimator to include a risk based allowance (i.e., contingency) to account for the inherent risks in any project estimate. The value of the contingency amount is dependent on the risk profile(s) of the project components and the status of project definition at the time of the estimate. For purposes of the PSEP estimate, SPEC Services developed contingency percentages following common industry practices and its prior experience on similar projects. Guidelines for estimating contingency developed by the DOE summarized in the following table corroborate the contingency levels for "Planning" estimates utilized by SPEC Services in their pipe replacement and pressure test cost estimates.

Table 11-1. Contingency Allowance Guide By Type of Estimate

Type of Estimate	**Overall Contingency Allowances** **% of Remaining Costs Not Incurred**
PLANNING (Prior to CDR) Standard Experimental/Special Conditions	20% to 30% Up to 50%
BUDGET (Based upon CDR) Standard Experimental/Special Conditions	15% to 25% Up to 40%
TITLE I	10% to 20%
TITLE II DESIGN	5% to 15%
GOVERNMENT (BID CHECK)	5% to 15% adjusted to suit market conditions
CURRENT WORKING ESTIMATES	See Table 11-2
INDEPENDENT ESTIMATE	To suit status of project and estimator's judgment

DOE Office of Management Directive[20]

As a project matures through its natural life cycle (e.g., moving from a preliminary/planning estimate to a more complete estimate), the amount of required contingency generally decreases to reflect the greater certainty of estimate assumptions and additional project design detail, while the amount of the base estimate will typically increase with the greater level of design completion. The following figure from the DOE Office of Management Directive demonstrates how contingency levels change throughout the life of a project.[21]

[20] DOE, Office of Management, Directive G 430.1-1 Chapter 11 – Contingency (Guide, 3/28/1997, MA).
[21] *Id.*

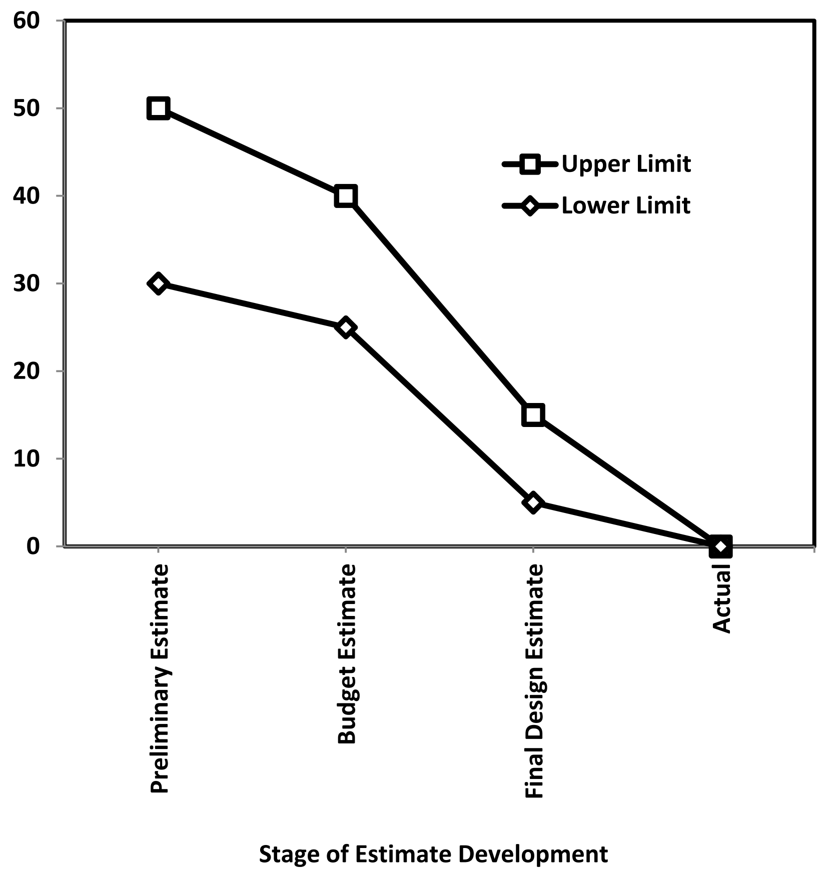

Figure 11-1. Contingency As a Function of Project Life

The DOE figure above illustrates that greater contingencies are needed early in project development when uncertainty and unknowns have yet to be evaluated. On the low end, in order to be at an 8% contingency a project would likely have to be approaching the Final Design Estimate. At that point considerable engineering, design, and planning would have already taken place.

B. SoCalGas' and SDG&E's approach to the PSEP contingency amount is consistent with prior Commission directives

With respect to prior Commission directives regarding estimate contingency, in D.09-03-026 related to PG&E's SmartMeter™ Program Upgrade Proceeding (A.07-12-009), the Commission concluded that risk based allowances (i.e., contingencies) included in project estimates should be based on the specific risk profile associated with a project rather than simply applying a contingency percentage previously adopted by the Commission on a different project. In that decision, the Commission stated:

> Consistent with the manner in which the risk based allowance adopted in D.06-07-027 was calculated, we will adopt a risk based allowance for the Upgrade costs. That PG&E's estimated overall Upgrade risk based allowance factor of 12.9% is higher than the 8.0% allowance for the original AMI project is a result of PG&E's analysis of risk for specific categories of Upgrade related costs as opposed to its analysis of risk for specific categories of costs for original AMI project. We agree with PG&E's position that the analysis of risk for the Upgrade should consider the risk profiles specific to the Upgrade, rather than that of the original AMI project.[22]

SoCalGas' and SDG&E's PSEP has a very different risk profile to the AMI projects cited by DRA. PSEP is comprised of multiple projects at very early phases of project definition and necessarily include a variety of assumptions and risks. For example, environmental permitting was not addressed in the estimates, and an assumption was made that all pressure test segments have a flat elevation profile. For the pipe replacement estimates, replacements were assumed to be done in the existing rights-of-way, and no additional costs were included for alternate pipe routings likely resulting in increased pipe quantities and construction man-hours nor right-of-way acquisition.

In contrast to PSEP, a large portion of the estimates related to the AMI programs cited by DRA were made up of defined procured equipment (e.g., meters and network equipment), which has a limited risk profile and a much lower contingency requirement than the PSEP components. In short, the weighted average contingency percentages for the two programs are simply not comparable and it would be wrong to use the eight percent contingency established for PG&E's AMI program as a "cap" for SoCalGas' PSEP contingency allowance. The contingency amounts

[22] D.09-03-026, mimeo., at 88.

established by SPEC Services for PSEP estimates reflect the risk profile of the PSEP, which is consistent with the prior Commission directive (and common industry practice).

C. DRA takes expert testimony related to a prior PG&E application out of context to support its contingency recommendations

In an attempt to support an 8% "cap" on PSEP contingency, DRA references the rebuttal testimony of PG&E witness, Stephen Lechner, in A.05-06-028. In this proceeding, Mr. Lechner referenced a 5-7% contingency for "standard construction projects" such as road and highway construction.[23] DRA then concludes that SoCalGas' and SDG&E's PSEP is more consistent with a "standard construction project," and thus should carry a contingency value of no more than 8%.[24] However, DRA takes the reference in Mr. Lechner's testimony out of context, which results in its inappropriate conclusion.

Specifically, DRA's citation to Mr. Lechner's AMI rebuttal testimony in the PG&E matter includes his reference to the California State Administrative Manual (SAM), Section 6854.[25] The specific reference out of the SAM section highlighted by Mr. Lechner is:

> Construction contingencies are limited to 5 percent of the construction estimate/bid for a new facility and 7 percent of the construction estimate/bid for remodeling/renovation projects.[26]

The 5-7% figures referred to in the SAM quotation above reflect contingency amounts for projects in a construction phase after awarding a bid (i.e., the "bid check" phase). This is the same as a "Class 1" estimate designation included in common guidelines established by the AACE. According to AACE tables, the contingency guideline for a "Class 1" estimate is 5%.[27] The projects included in SoCalGas' and SDG&E's PSEP reflect AACE Class 5 estimates, which

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[23] DRA Testimony (Roberts) at pp. III-24 and III-25.
[24] DRA Testimony (Roberts) at p. III-25.
[25] Exhibit 114, Rebuttal Testimony of Stephen P. Lechner in PG&E Application 05-06-028, page 15-5 (footnote 5).
[26] State Administrative Manual, Section 6854 (revised 5/98), paragraph 3.a.
[27] *See, e.g.*, US Office of Systems and Policy Support, Quality Guidelines for Energy System Studies, February 24, 2004, page 31, Tale 7 - AACE Standards for Project Contingency.

would typically include a contingency allowance of approximately 50 percent according to AACE guidelines.[28] DRA's recommendation that SoCalGas and SDG&E should apply a contingency amount consistent with the AACE recommendation for a "Class 1" estimate to the PSEP estimate, which is characterized as a "Class 5" estimate, is inconsistent with the specific requirements of the PSEP, common industry practices, and prior Commission directives.

V. SOCALGAS AND SDG&E ARE DEVELOPING A GOVERNANCE STRUCTURE AND CONTROL ENVIRONMENT TO DELIVER THE PSEP COMPONENTS IN A TIMELY AND COST-EFFECTIVE FASHION

Following the submission of their amended PSEP in December of 2011, SoCalGas and SDG&E have continued to focus on developing an execution approach and governance structure for this complex program. Although estimating and cost control methods are used on the projects we routinely execute today the size, schedule, and complexity of the PSEP warrant a more robust form of project governance. The objective of this effort is to establish a comprehensive control environment that will include transparent processes and procedures for program execution, a structured organization delineating clear roles and responsibilities of program participants, and detailed reporting requirements to support senior management and Commission oversight of program performance. As part of this effort, SoCalGas and SDG&E are actively engaged with PG&E and other utilities throughout the nation working on gas pipeline pressure testing and accelerated replacement programs to take advantage of their experiences and to establish procedures and controls that will best suit the needs of our PSEP.

SoCalGas and SDG&E are currently in the final stages of selecting an experienced program management contractor to support the execution of the PSEP. SoCalGas and SDG&E have solicited bids from qualified contractors through a formal Request for Proposal (RFP), and

[28] *Id.*

we are performing a rigorous assessment of contractor submittals. Following selection of the program management contractor, SoCalGas and SDG&E will formalize our PSEP governance structure and overall control environment. This control environment will follow leading industry approaches to actively manage the key elements of PSEP execution, including:

- Detailed project planning incorporating technical input from program engineering and pipeline operations;
- Procurement and contract administration;
- Cost management (estimating, budgeting, contingency analysis/draw-down, recorded costs, forecasts to complete);
- Schedule management (planning and managing testing and pipe replacement activities while maintaining the reliability of natural gas services to SoCalGas and SDG&E customers);
- Scope and change control;
- Quality and inspections;
- Safety management (employee, contractor and general public);
- Environmental compliance;
- Issue and risk management (including quantitative analysis of program risks); and
- Communication and reporting (including performance metrics development and monitoring and customer relations).

By establishing a comprehensive governance structure and robust control environment, SoCalGas and SDG&E will be able to effectively manage the multiple, complex elements of PSEP, while maintaining a transparent mechanism to demonstrate to senior management and the Commission that we are achieving the important objectives of PSEP in a cost-effective and efficient manner. Having detailed processes, procedures, and reporting protocols, along with clear accountability for PSEP performance, will allow SoCalGas and SDG&E to respond quickly to the results of pipeline testing and engineering recommendations. This approach also will allow SoCalGas and SDG&E to deliver the Commission's desired safety enhancements to our natural gas transmission infrastructure in an expedited fashion with limited disruption to gas services, and at a reasonable cost to our customers.

The proposal by SoCalGas and SDG&E to move forward with PSEP on a forecasted and expedited basis is consistent with prior Commission precedent. Specifically, this is a similar situation to the various AMI programs in California, where the Commission adopted advance forecasts for AMI program implementation to achieve its market transformation objectives. The Commission then held the utilities accountable for active program management using leading industry practices to support the reasonableness of their management actions and resulting costs.

For example, in the first AMI proceeding fully litigated before the Commission, PG&E set out its comprehensive integrated program management approach for its AMI program, which supported the Commission's contemporaneous oversight of the AMI program activities and associated costs. In this matter, the Commission concluded the estimated project costs were "within the range of a likely litigated outcome" and included "a risk based allowance for unforeseen events."[29] The Commission then adopted an approach allowing recovery of incurred costs up to an approved cost cap without the burden of future reasonableness reviews, noting that PG&E had "demonstrated it will use an appropriate management structure to effectively control the AMI project."[30]

[29] D.06-07-027, mimeo., at 62 (Finding of Fact No. 8).
[30] D.06-07-027, mimeo., at 18.

SoCalGas and SDG&E recommend that the Commission adopt this same approach for PSEP. As described above, SoCalGas and SDG&E are committed to implementing a strong program governance structure and control environment for the PSEP following leading industry practices. This approach not only supports the Commission's contemporaneous oversight of program activities, but it also allows SoCalGas and SDG&E to manage the overall PSEP in a way that delivers the program in an expedited fashion at a reasonable cost to their customers.

This concludes my prepared rebuttal testimony.

CHAPTER 10

SPECIFIC PROJECT CLARIFICATIONS

AND LINE 1600

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PREPARED REBUTTAL TESTIMONY

OF DAVID M. BISI

I. PURPOSE

The purpose of my rebuttal testimony is to:

1. Correct certain misunderstandings in the testimony of the Division of Ratepayer Advocates (DRA) regarding the plan of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) to replace Line 41-6000-2 with an extension of Line 6914 in the Imperial Valley;

2. Further explain SoCalGas' and SDG&E's plan for Supply Line (SL) 38-959 and SL 38-539; and

3. Address DRA's and the Southern California Generation Coalition's (SCGC) statements about the plans by SoCalGas and SDG&E to inspect and pressure test Line 1600, and further explain this proposed project.

II. ADDITIONAL DETAIL REGARDING PLANS FOR LINE 41-6000-2 AND LINE 6914

DRA witness Ms. Dao Phan recommends in her Prepared Direct Testimony that the Commission reject certain pipeline replacement projects because "Sempra is trying to use the [pipeline safety enhancement] plan to increase capacity without justification."[1] Specifically, Ms. Phan identifies the plan for Line 41-6000-2 and Line 6914 as examples of this behavior. SoCalGas and SDG&E believe that Ms. Phan has misunderstood the plan for these pipelines.

SoCalGas and SDG&E propose to abandon 36 miles of Line 41-6000-2, and replace its functionality with a new 24-inch diameter, 11-mile extension of existing Line 6914. Another 2.5 miles of 10-inch diameter pipeline will extend from the existing Line 6914 to the distribution

[1] DRA Testimony (Phan) at p. 49.

system south of El Centro, and the remaining 13 miles of smaller diameter pipeline are necessary to tie the distribution system that is currently supplied by Line 41-6000-2 into Line 6914. This plan was described in detail in the SoCalGas and SDG&E response to SCGC's 11th data request in R.11-02-019/A.11-11-002.

Ms. Phan's statement that "This project does not appear to have been planned based on the criteria used in the Decision Tree . . .,"[2] is not accurate. As explained in our response to SCGC's 11th data request:

> **The high level evaluation of this pipeline performed to determine the proposed scope indicated that the line could not be taken out of service for pressure testing with manageable customer impacts. Since the pipeline is also not piggable, per the decision tree on page 61 of the testimony this line is routed into Box 2 "Replace and Abandon."** Once the replacement facilities are installed, it would be possible to take Line 41-6000-2 out of service to pressure test. However, **preliminary evaluation suggests there may be little incremental benefit to keeping this aged asset. As such, the proposed action is to abandon Line 41-6000-2 in place.** Detailed planning and scope definition will be performed during the engineering, design, and execution planning phase of the project.[3]

Contrary to Ms. Phan's assertion, SoCalGas and SDG&E did in fact use the Decision Tree criteria to develop the plan for Line 41-6000-2. Line 41-6000-2 operates in Class 3 and high consequence areas, lacks adequate pressure testing documentation, is longer than 1000 feet, cannot be taken out of service without manageable customer impact, and is not piggable. The Decision Tree calls for this pipeline to be abandoned and replaced, which is what SoCalGas and SDG&E plan to do. The replacement pipeline will simply be a pipeline other than Line 41-6000-2.

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[2] *Id.* at p. 50.
[3] This particular set of data responses is Attachment I to Ms. Yap's Testimony. *See* Response 11.4.7 at p. 7 (emphasis added).

Ms. Phan further states "DRA asked Sempra about this project and Sempra stated that it was a "capacity planning" project."[4] This statement is incorrect. SoCalGas and SDG&E do not contest that the capacity of the Imperial Valley gas network will increase under our proposed plan for Lines 41-6000-2 and 6914, and in fact we have quantified that capacity increase in our response to SCGC Data Request 11.[5] However, SoCalGas and SDG&E have never represented that our plan was a "capacity planning project." Rather, our plan for these particular lines was developed from an examination of the preliminary costs to inspect and replace Line 41-6000-2 as well as alternate projects, which could be less expensive and more beneficial from a system-wide perspective. This was explained in our response to SCGC's Data Request 11.4.8:

> High level cost estimates indicate that it may be more cost effective to install 11 miles of 24-Inch pipe to the north and 2.5 miles of 10-Inch pipe to the south, tie-in both pipelines to Line 6914, and abandon all of Line 41-6000-2, rather than replace kind-for-kind the full length of Line 41-6000-2.[6]

SoCalGas and SDG&E understand that the extension of Line 6914 is a larger diameter than the pipeline that it replaces (i.e., Line 41-6000-2). However, the existing segment of Line 6914 is 24-inch diameter and SoCalGas' Line 6902, which runs between Hayfield Station and Niland Station, is also 24-inch diameter. This new 11-mile extension is therefore between two existing 24-inch pipelines, and it does not make sense from a system design perspective to use a smaller diameter pipeline and thereby unnecessarily create a new pipeline constraint.

Finally, Ms. Phan states that "L-6914 was installed in 2009 and is not a pipeline that should be included in the group of pipelines affected by the Decision to test or replace."[7]

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[4] DRA Testimony (Phan) at p. 50.
[5] As explained in our Response 11.4.16, "The projected nominal throughput capacity of Line 6914 including the expansion is approximately 200 MMcfd. The projected actual capacity may be less depending upon location of demand in the Imperial Valley."
[6] *See* Attachment I to Ms. Yap's Testimony at p. 8.
[7] DRA Testimony (Phan) at p. 51.

SoCalGas and SDG&E agree, and note that we did not include the existing segment of Line 6914 (the one "installed in 2009") in our pipeline safety enhancement plan (PSEP).

III. ADDITIONAL DETAIL REGARDING PLANS FOR SL 38-959 AND SL 38-539

Ms. Phan also identified SL 38-959 and SL 38-539 as two projects which should be removed from the SoCalGas and SDG&E PSEP because both replacement pipelines will provide incremental capacity to the adjacent local distribution systems. While incremental distribution capacity will indeed be a product of the replacement of these two pipelines, SoCalGas and SDG&E disagree that these two pipelines should be removed from our PSEP.

Both supply lines meet the necessary criteria to be included in the SoCalGas and SDG&E PSEP. SL 38-959 operates in a Class 3 location, and a segment of SL 38-539 operates in an HCA. Both lines lack adequate documentation of pressure testing, have criteria mileage longer than 1,000 feet, cannot be removed from service with manageable customer impact, and are not piggable. Per the SoCalGas and SDG&E PSEP Decision Tree, both pipelines should be abandoned and replaced.

Furthermore, SL 38-959 is a single feed supply line that serves several large customers with growing demand, and SL 38-539 serves an area currently experiencing low operating pressures. SoCalGas plans to replace both pipelines with larger diameter pipeline as part of its ongoing "pressure betterment" program in order to meet its customer demand.[8] SoCalGas and SDG&E believe that it makes little sense to replace them with like-diameter pipelines now for the PSEP, only to later incur additional costs to replace that pipeline with a larger one. By upsizing now, SoCalGas and SDG&E ratepayers avoid those additional costs in the pressure betterment program.

[8] As explained at page 44 of SoCalGas' and SDG&E's PSEP, costs presented in the PSEP are incremental to those in SoCalGas' and SDG&E's General Rate Cases, A.10-12-006 and A.10-12-005, respectively, and as such, neither SL 38-959 nor SL 38-539 were included in the General Rate Cases for replacement.

IV. LINE 1600

Both Ms. Phan and SCGC witness Ms. Catherine Yap discuss the SoCalGas and SDG&E plan for inspecting and pressure testing Line 1600 in San Diego, and both recommend that the work related to the pressure test be addressed in Phase 1B.[9] Both DRA and SCGC are also critical of the SoCalGas and SDG&E plan to construct a 36-inch diameter pipeline to replace Line 1600.[10]

The plan of SoCalGas and SDG&E for pressure testing Line 1600 is already a predominately Phase 1B project. As explained in our testimony, the lack of sufficient documentation of pressure testing for Line 1600 would classify some of it as a Phase 1A project. However, it is necessary to construct a replacement pipeline before removing Line 1600 from service for testing in order to avoid the adverse customer impacts such removal from service would cause. A project of the scale of this pipeline replacement proposal cannot be completed within the timeframe for Phase 1A, and therefore is planned for Phase 1B. SoCalGas and SDG&E explained this in our comments to the technical report of the Commission's Consumer Protection and Safety Division (CPSD) on our PSEP, in which we stated that the replacement is "expected to trigger extensive local, state and federal permitting requirements as well as CEQA review, which will likely require an environmental impact assessment . . .,"[11] and that we "anticipate the time for design, CEQA compliance and permitting to take up to three years. For this reason, the actual construction would not begin until Phase 1B."[12]

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[9] DRA Testimony (Phan) at p. 80; SCGC Testimony (Yap) at p. 17. In addition, Ms. Phan recommends that the costs related to the transverse field inspection (TFI) of Line 1600 be removed from Phase 1A. (DRA Testimony (Phan) at p. 81.) The reason why TFI of Line 1600 is an appropriate Phase 1A cost is addressed later herein, and in the Rebuttal Testimony of SoCalGas/SDG&E witness Douglas Schneider.
[10] DRA Testimony (Phan) at p. 81; SCGC Testimony (Yap) at p. 20.
[11] R.11-02-019, January 27, 2012 Comments of SoCalGas and SDG&E on Technical Report of CPSD at p. 6.
[12] *Id.*

The fact that construction could not begin until Phase 1B does not mean, however, that it is appropriate to permit recovery of costs of this project only in that future period. The only costs related to Line 1600 which SoCalGas and SDG&E proposed for Phase 1A are those necessary to perform an in-line inspection and begin the pre-engineering for the replacement pipeline. As DRA notes, the costs for the pre-engineering work represent only 4% of the total replacement pipeline costs. Significantly, such pre-engineering work is necessary regardless of the pipeline diameter selected for the Line 1600 replacement pipeline, and the cost of such work will not vary materially with different sized pipelines. Deferring necessary pre-engineering work for L1600 to Phase 1B will delay the entire project to test the pipeline, and thus almost certainly extend it past the Phase 1B timeframe.

Seeking to bolster her criticism of the modest Phase 1A costs SoCalGas and SDG&E have proposed in connection with Line 1600, Ms. Yap makes note that SoCalGas and SDG&E have voluntarily reduced the Maximum Allowable Operating Pressure (MAOP) of Line 1600 from 800 to 640 psig, and states that SCGC believes that "the Applicants' actions have clearly created a substantial safety margin."[13] Further, SCGC supports the use of TFI technology, and goes on to state that "the reduction in pressure on Line 1600 combined with the TFI testing during Phase 1A removes the urgency of considering any additional safety testing . . ..."[14]

SoCalGas and SDG&E agree with Ms. Yap that TFI technology is promising and we do believe that lower operating pressures on Line 1600 have created a safety margin. The fact is, however, that the Commission has not ruled that lowering the operating pressure and using TFI technology obviates the need for pressure testing. SoCalGas and SDG&E are obliged to

[13] SCGC Testimony (Yap) at p. 19.
[14] *Id*. at p. 21.

develop a safety plan which follows the rules and requirements established by the Commission and the state legislature. As such, our safety plan requires that Line 1600 be pressure tested, and in order to complete this test without significant service and customer impacts, a replacement line needs to be installed prior to the pressure test. In its technical report on our PSEP, CPSD agrees with SoCalGas and SDG&E in this regard:

> There can be circumstances, however, in which a segment of pipeline cannot be taken out of service without a service disruption. An example of this is the Companies Line 1600 which, because it serves as a sole source of natural gas for several large customers and a distribution system in San Diego, is required by operations to flow large volumes of gas on a fairly constant basis.[15]

Both DRA and SCGC are critical of the SoCalGas and SDG&E plan to construct the replacement of Line 1600 as a 36-inch diameter pipeline.[16] SoCalGas and SDG&E have already presented several operational benefits that would derive from a larger diameter pipeline in San Diego County, including improved reliability, additional customer capacity, and reduced compression requirements. SoCalGas and SDG&E also believe that the available routes for a pipeline project of this magnitude in San Diego County are extremely limited, and we are reluctant to use that limited routing capability for a pipeline which cannot meet the long-term needs of customers located in San Diego County.

However, SoCalGas and SDG&E wish to remind intervenors and the Commission that we are <u>not</u> seeking approval from the Commission to recover costs related to the installation of a 36-inch pipeline in San Diego at this time. In Phase 1A, we are only requesting recovery of the costs to begin the preliminary engineering of a Line 1600 replacement pipeline project. In our judgment, a 36-inch pipeline is the most appropriate size for such replacement pipeline, for the reasons summarized above and as noted in our comments on the CPSD report. There

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[15] R.11-02-019, January 17, 2012 Technical Report of CPSD Regarding the SoCalGas and SDG&E PSEP at p. 5.
[16] DRA Testimony (Phan) at p. 81; SCGC Testimony (Yap) at p. 20.

is ample time, however, to debate the diameter of a new San Diego pipeline in the future, and whether that pipeline is ultimately 16-inch, 36-inch, or some other diameter will not appreciably change the preliminary engineering and associated costs needed in Phase 1A.

In this regard, both DRA and SCGC recommend that SoCalGas/SDG&E file a separate application for the replacement pipeline in San Diego.[17] It is the intention of SoCalGas and SDG&E to pursue such an application at some time in the future. The fact that an application would be forthcoming, however, hardly supports prohibiting SoCalGas and SDG&E from performing and recovering the costs of the preliminary engineering work that is needed now to fulfill our pipeline safety obligations.

This concludes my prepared rebuttal testimony.

[17] DRA Testimony (Phan) at p. 81; SCGC Testimony (Yap) at p. 21.

CHAPTER 11

VALVE ENHANCEMENT PLAN, TECHNOLOGY, AND ENTERPRISE ASSET MANAGEMENT

TABLE OF CONTENTS

PREPARED REBUTTAL TESTIMONY

OF JOSEPH M. RIVERA

I. PURPOSE OF REBUTTAL TESTIMONY

The purpose of my testimony is to clarify aspects of Southern California Gas Company (SoCalGas) and San Diego Gas and Electric's (SDG&E) testimony and refute mischaracterizations made by the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), and the Utility Workers Union of America (UWUA) regarding SoCalGas and SDG&E's Valve Enhancement Plan, Technology Plan, and Enterprise Asset Management blueprint project. This testimony will show that adoption of DRA, TURN, and UWUA's proposals will not achieve the Commission's objectives.

Generally, DRA, TURN, and UWUA have proposed changes which would delay, scale back, and fragment the proposed Plans. More specifically, DRA, TURN and UWUA have collectively proposed:

- Changing the spacing criteria;
- Introducing an automatic shut-off valve only approach to valve technology;
- Eliminating or scaling back specific Valve Plan work elements which are required for a cohesive plan and technical success;
- Delaying Valve Enhancement Plan implementation due to alleged cost estimate inaccuracies or uncertainties;
- Delaying or rejecting SoCalGas and SDG&E proposed Technology Plan; and
- Limiting and/or denying Enterprise Asset Management development.

SoCalGas and SDG&E believe these recommendations to be misguided and ineffective in creating a safer pipeline system.

II. SUMMARY OF SOCALGAS AND SDG&E'S VALVE, TECHNOLOGY, AND EAM PLAN

The basis for my original testimony, which detailed SoCalGas and SDG&E's Valve, Technology, and Enterprise Asset Management proposals, was to provide a comprehensive and forward-looking approach to enhancing pipeline safety and deliver on the intent of R.11-02-019 and D.11-06-017. SoCalGas and SDG&E's proposals delivered on four guiding principles:

1. responds to the Commission's order;
2. enhances public safety;
3. minimizes customer impacts; and
4. minimizes costs by leveraging the Utilities existing infrastructure.

Consistent with these principles, SoCalGas and SDG&E designed their plans to develop and implement prudent, responsible, and manageable enhancements, consistent with the Commission's directives.

On the other hand, DRA, TURN, UWUA set forth proposals which are unresponsive to Commission directives, trade minimal and speculative costs savings for decreased public safety, ignore customer impact, and fail to leverage the Pipeline Safety Enhancement Plan (PSEP) and existing infrastructure to enhance pipeline safety.

III. VALVE ENHANCEMENT PLAN

A. Valve Enhancement Plan Summary

SoCalGas and SDG&E's Valve Enhancement Plan was formulated to provide for timely isolation of larger high-pressure pipelines routed through Location Class 3 & 4 areas and High Consequence Areas (HCAs) in the event of a rupture. Specifically, the plan proposed the automation of manual valves to operate as Remote Control Valves (RCVs) and Automatic Shut-off Valves (ASVs).

B. Intervener Positions

TURN and DRA, relying on the Consumer Protection and Safety Division's (CPSD) Technical Report on SoCalGas and SDG&E's Pipeline Safety Enhancement Plan (PSEP), conclude that the Valve Enhancement Plan can be modified, delayed, or parsed out to omit or push certain elements to other regulatory proceedings. Specifically, TURN and DRA propose:

- Reliance exclusively on ASVs as opposed to a mix of RCVs and ASVs to reduce costs;
- Increasing valve spacing from 8 to 16 miles to reduce plan scope and cost;
- Delaying implementation due to alleged cost uncertainties; and
- Removing key companion elements to reduce scope and cost.

TURN and DRA's proposals, however, are shortsighted, unresponsive to the Commission's directives, and ignore the complexities of SoCalGas and SDG&E's pipeline system.

C. SoCalGas and SDG&E Rebuttal

1. Integrated Plan

DRA and TURN propose modifying, delaying, and eliminating elements of the Valve Enhancement Plan. Any plan-limiting proposals, however, ignore the complexities of SoCalGas and SDG&E's pipeline system as it relates to implementing a workable isolation plan. The assets required to effectively implement SoCalGas and SDG&E's Valve Enhancement Plan are considerable and include installation and/or modifications of 461 valves, extending communication to 100 other valves, expanding Supervisory Control and Data Acquisition (SCADA) and communication systems, installing field instrumentation to monitor pipeline events and parameters, and modifying pipeline assets to prevent the unwanted backflow of gas into ruptured pipeline sections from tap lines and regulator stations. The plan is highly integrated and is not easily fragmented or scaled back due to the complexity in isolating networked inter-connected pipelines and the interdependencies between each plan element. As such, we ask the Commission to support our integrated Valve Enhancement Plan in its entirety.

2. ASVs versus RCVs

TURN and DRA rely on aspects of the CPSD report in recommending that SoCalGas and SDG&E install ASVs instead of RCVs or operate dual capability valves in ASV mode to monitor performance and determine ASV effectiveness. DRA and TURN assert that if ASVs are installed, then the spacing intervals for isolation can be moved from 8 to 16 miles while achieving the same net depressurization time. This zero-net-sum is postulated to be secured by trading reduced ASV activation time for an expanded time required to evacuate gas from a longer stretch of pipeline in the event of a rupture. This proposal, however, does not consider instances where an ASV may not enhance isolation at all or lead to customer loss of service due to false closures.

TURN and DRA's ASV installation proposal will not improve on our ability to isolate pipelines in a timely manner or enhance safety. As discussed in greater detail below, SoCalGas and SDG&E operate a complex pipeline system which requires thoughtful and thorough valve deployment and other supporting assets to appropriately respond to a rupture. Simply placing ASVs at 16 mile intervals where pipelines are routed in Location Class 3 and 4 areas and HCAs will lead to ineffective rupture isolation. In short, DRA and TURN's proposals are inconsistent with facts and the realities of how SoCalGas and SDG&E pipelines are configured and operated.

Next, TURN and DRA fail to adequately address the significant customer impact which could result from false closures. While CPSD acknowledges the false closure risks associated with ASVs, TURN and DRA choose to ignore or highly discount potential customer impacts. SoCalGas and SDG&E have provided the interveners with evidence of false closures and the risks associated with the same. SoCalGas and SDG&E believe that we must manage the risk and consequences of outages on our system, and prevent such outages where possible. Consistent with this, SoCalGas and SDG&E have crafted their Valve Enhancement Plan to balance cost, complexity, event management and service security for customers.

TURN attempts to discount SoCalGas and SDG&E's false closure concerns by casually suggesting that SoCalGas and SDG&E's experiences with valves installed and operated for decades are irrelevant because SoCalGas and SDG&E have not documented situations where wide-scale customer loss has accompanied an ASV closure. Indeed, despite being provided with data regarding false closures on the SoCalGas/SDG&E system, TURN concludes that lacking a documentation trail of numerous unplanned or unexplained valve closures resulting in wide-scale customer loss, the false closure risk is not a legitimate concern.

SoCalGas and SDG&E find TURN's reasoning and interpretation of the failure data to be convoluted and challenged. The lack of service interruptions stems from SoCalGas and SDG&E intensive efforts to design and deploy its ASVs to avoid negative consequences. Moreover, SoCalGas and SDG&E's previous ASV deployments have been limited to regions outside of complex piping areas like the LA Basin. The reality is that forward-looking expansion of our pipeline isolation success into areas where the stakes and risk associated with false closures are higher requires different thinking and analyses. To assume that a valve isolation plan for a Location Class 3 or 4 area or HCA can be structured based on extrapolating a successful

Location Class 1 valve isolation plan ignores the complexity of the system; a complexity thoughtfully addressed in our Valve Enhancement Plan.

Finally, TURN Witness Marcus attempts to support his ASV preference by citing a 12-year old incident and matter-of-factly concluding that RCVs are not reliable technology for isolation purposes.[1] A detailed analysis of the incident, however, reveals, that the RCV was not the cause, or even a contributing factor, of the incident. To the contrary, the incident was caused by an apparent lack of program and alarm management. Thus, the same incident could just as easily have unfolded using ASVs with improperly set program and alarms. As such, this incident actually illustrates the importance of control programming and alarm management -- a cornerstone of SoCalGas and SDG&E's Valve Enhancement Plan. In short, despite strained efforts to draw parallels, the incident cited by Mr. Marcus offers no support to his ASV proposal.

The interveners have gone to great lengths to challenge SoCalGas and SDG&E's Valve Enhancement Plan, mischaracterizing aspects of CPSD's report, misinterpreting past incidents, and attempting to compare SoCalGas and SDG&E's use of ASVs in Location Class 1 and 2 areas to the current Valve Enhancement Plan. Such strained reasoning and logic, however, ignore facts and inappropriately challenge the propriety of SoCalGas and SDG&E's well-thought out proposal.

3. Valve Spacing

TURN and DRA again largely rely on the CPSD's technical report in proposing that valve spacing can be modified from the current 8 to 16-mile spacing. TURN and DRA, however, again fail to address a number of issues and ignore aspects of the CPSD report.

Briefly, the CPSD report deemed SoCalGas and SDG&E's plan to be technically sound, but suggested that the 30 minute isolation/depressurization objective might also be met by using

[1]TURN Testimony (Marcus) p. 10-11.

ASVs and extending the spacing intervals to 16 miles. The rationale for the CPSD's proposal was that ASVs might be able to detect and begin to isolate a ruptured pipeline 10-15 minutes sooner than an RCV subject to latencies associated with a remote operator identifying a pressure excursion on his SCADA system and initializing remote valve closures. This theoretical ASV time advantage could then be leveraged to allow for a longer section of pipeline to be depressurized with the net time for pipeline depressurization remaining at 30 minutes. The approach and reasoning associated with CSPD's proposal is commendable and similar to the spacing and time dimensions associated with SoCalGas and SDG&E's deployment of ASVs on its pipelines in outlying, simplified pipeline sub-systems. This approach and reasoning, however, is inadequate in many Location Class 3 and 4 areas and HCAs.

More specifically, placing valves at 16 mile intervals in many instances will not provide for complete isolation of many pipeline sections located in Location Class 3 and 4 areas and HCAs or may not result in less isolation valves when compared to an eight-mile isolation plan. Pipelines in many populated areas are configured such that they are effectively a grid matrix of pipelines connected every 5 to 8 miles. Thus, attempting to properly install ASVs and RCVs at 16-mile sections will end up looking almost exactly like an eight-mile isolation plan in terms of valve count.

To illustrate, Attachment A, Figures A.1 and A.2 depict actual piping configuration on the SoCalGas pipeline system and are typical of pipelines routed in Location Class 3 and 4 areas and HCAs. Figure A.1 shows how a major pipeline section, referenced as SCG1, approximately 16 miles long, would be shutdown/isolated using two mainline valves A and C (yellow) in the event of a rupture in section A-C. Significantly, because of the potential for back-flow from interconnected pipelines, some of which connect with other major pipelines less than 8 miles from their connection point with Line SCG1, a total of eleven valves and/or backflow prevention controls must be employed. Figure A.2 in Attachment A shows the assets required to isolate a rupture in either section A-B or B-C of the same pipeline segment, incorporating an 8 mile control strategy by providing the added capability to close valve B.

Noticeably, the net increase in valves and control devices using eight-mile spacing is only one more valve. Thus, there is little effective difference in valve count required for isolating this section, whether one attempts to employ an 8 or 16 mile isolation strategy. Moreover, this diagram also illustrates how, in a complex pipeline system, simply installing a valve every 16 miles and expecting to isolate a section of pipeline is simply not possible.

To better illustrate the complexity of SoCalGas' system, Attachment A, Figure A.3 provides an overview of the LA Basin's major higher pressure pipeline system. A 16x16 mile square grid has been superimposed to show how many sub-grids and interconnection points exist in a typical 16 mile grid. One can see that attempting to isolate any portion of a grid with only four valves or with valves spaced at 16 miles becomes virtually impossible. It is for this reason that SoCalGas and SDG&E find the CPSD's and intervener's recommendation in this matter unworkable under a reduced valve count proposal.

In conclusion, DRA and TURN's proposal is rooted in a lack of technical understanding and the Commission should not modify the valve spacing nor scale back the Valve Enhancement Plan submitted by SoCalGas and SDG&E. SoCalGas and SDG&E believe employing the appropriate isolation interval on a lesser total of pipeline mileage makes more sense than half measures across our entire system, which would result in little added isolation enhancement. Indeed, to try and fully implement our isolation strategy for the pipeline sections indicated in our plan, but with a 50% reduction in valve count, would constitute technical folly and be a waste of ratepayer money.

4. Cost Estimates

TURN Witness Marcus takes issue with SoCalGas and SDG&E's estimated valve cost methodology, recommending a downward adjustment to these costs because the submitted estimates employ some averaging of costs provided by contractors with costs developed by SoCalGas and SDG&E.[2] Furthermore, based on an observation of scope and cost differences between the averaged estimates, Witness Marcus recommends a downward adjustment to all estimates prepared and an elimination of the 8% contingency.

SoCalGas and SDG&E acknowledge that any single valve installation costs within a broad scope category can vary widely, sometimes up to 50%. This variance was due simply to the number of differing valve sites, over 500, and an assumption that each valve site might have a slightly different work scope complexity. As such, SoCalGas and SDG&E's estimate averaging was intended to recognize that, even within the general scope of valve work, there can exist different sub-work elements (for example, whether a tap to serve customers is located at the valve site). In an effort to provide the interveners with a better understanding of this reality, SoCalGas and SDG&E responded to Data Request DRA-KCL-05 by providing Table DRA-KCL-05-03. There, SoCalGas and SDG&E provided the recorded and expected final (where several installations were 90% or more complete) costs for multiple recent valve installations, many of which reflect the scope of work to be performed as part of our PSEP. The average recorded cost for these installations was $1.201 million per site. An examination of our averaged cost for this type of work, as forecasted on workpaper page WP-IX.B.4-29, is shown to be $1.171 million. The difference between our forecast for work of this type and the recorded cost

[2] TURN Testimony (Marcus), p 14.

is well within our 8% cost contingency at approximately 3%. Given this clear similarity, it is unclear whether TURN reviewed or analyzed the data provided in Response to DRA-05 in the context of our submitted cost estimates.

While TURN may not have had cause to review DRA Data Request Responses in detail, DRA has simply ignored and or discounted the provided information. DRA suggests SoCalGas and SDG&E "have not provided relevant automatic valve replacement cost history."[3] SoCalGas and SDG&E find DRA's position confusing given that DRA was provided relevant data in response Table DRA-05-03. If necessary, SoCalGas and SDG&E would be open to providing DRA with assistance in interpreting the information.

Finally, where cost estimates are concerned, both DRA and TURN equate SoCalGas and SDG&E's testimony regarding pipeline and hydrotesting cost estimates with Valve Enhancement Plan cost estimates. Both interveners specifically cite language from our Amended Testimony stating "Cost Estimates are preliminary and were developed based on minimal engineering, operational planning and project execution planning."[4] These caveats do not apply to our Valve Enhancement Plan cost estimates. We submit or clarify here that our valve costs, on the whole, are plus or minus 10% estimates, as an average, for all work included in our Valve Enhancement Plan. Our most recent history corroborates and validates our cost estimation methodology. Simply stated, TURN and DRA's position in this matter do not reflect consideration of our empirical costs and should be rejected.

5. New Pipeline Installations

TURN Witness Marcus recommends denial of approximately $76 million in funding for certain pipelines being replaced, suggesting such pipelines do not require replacement or may not

[3] DRA Testimony (Lee), p. 7.
[4] SoCalGas and SDG&E Amended Testimony, page 103, lines 23-24.

need valves.[5] SoCalGas and SDG&E disagree with this assessment and offer that, regardless of whether a pipeline is replaced or retained, the pipe segment still requires an ASV/RCV pursuant to our plan criteria.

As discussed previously, SoCalGas and SDG&E operate a complex and interconnected grid of pipelines in HCAs and populated areas. To categorically eliminate valves on new pipelines routed in these areas ignores this complexity and severely limits the effectiveness of our Valve Plan to adequately support in isolating and depressurizing our pipelines in the event of rupture. Quite simply, Marcus' proposal, which denies funding for ASVs/RCVs for either existing or new pipelines, is seemingly another fragmenting, cost-saving recommendation which fails to consider public safety.

6. Removal of Key Elements

DRA and TURN propose denying funding of important and integral elements of the Valve Enhancement Plan including backflow prevention devices, radio communication systems, and ASV/RCV dual functionality. SoCalGas and SDG&E believe DRA and TURN's proposals to be entirely without technical merit and amount to the interveners cutting integral aspects of the Valve Enhancement Plan; sacrificing effectiveness in misguided efforts to lower costs.

Notably, the importance of these companion enhancement elements was recognized by CPSD, evidencing willingness by DRA and TURN to rely on the CPSD report only when it suits their purposes:

> **FINDING**: The additional enhancement measures related to automated valves, as proposed by the Companies, would improve current performance and CPSD recommends that the CPUC allow the Companies to proceed with their proposal to install telemetry facilities and backflow prevention devices at all locations as planned. CPSD believes these readings are crucial because

[5] TURN Testimony (Marcus), p.15-16.

they allow for pin-pointing failure locations and will assist in first response efforts to any failure events.[6]

As supported by CPSD, SoCalGas and SDG&E proposed these key elements to deliver on achieving a shortened-response time for gas flow shutoff in the case of a pipeline rupture. These intervener recommendations to remove these elements from our plan, we believe, are flawed and in direct opposition to the CPSD's recommendation to move forward with the installation of communications and backflow devices.

a. Backflow Prevention Devices

DRA dismisses the backflow prevention devices as being distribution-type assets. SoCalGas and SDG&E believe this to be a shortsighted and dangerous conclusion. Simply stated, in the event of a rupture, without backflow prevention devices to prevent backflow, natural gas would continue to flow into a ruptured segment. Indeed, were two mainline RCVs/ASVs to be activated, there would be sufficient backflow to inhibit emergency response until manual closure(s) could be executed, defeating the purpose of the investments made with the RCV/ASV. Without question, backflow is an issue relative to isolating and depressurizing a ruptured pipeline segment. For example, a review of the August 2000 Carlsbad incident[7] demonstrates how isolation can be delayed because of failure to address backflow. There, gas flowed back into the ruptured segment and was noted as the reason why a ruptured pipeline segment was not fully isolated once the main line valves were closed.

To help further illustrate the need for backflow devices as proposed by SoCalGas and SDG&E, Attachment B, Figure B.1 depicts a very simplified situation where backflow devices and accompanying sensors would help mitigate gas flow. Figure B.1 can also be used to

[6] CPSD's TECHNICAL REPORT OF THE CONSUMER PROTECTION AND SAFETY DIVISION REGARDING THE SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS AND ELECTRIC COMPANY PIPELINE SAFETY ENHANCEMENT PLAN, R.11-02-019, page 16.

[7] NTSB/PAR-03/01, PB2003-916501, Pipeline Accident Report, Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico, August 19, 2000, page 8.

illustrate the issues with DRA's proposal. DRA proposes retrofitting valves A1, A2, B1, and B2, but would deny funding for valves C1 and C2. Valves C1 and C2, along with associated companion technologies such as flow meters and sensors, are an integral part of the design philosophy to support improved shutoff times by preventing backflow from entering a ruptured pipeline segment. This problem would be further exacerbated if the Commission adopted the 16-mile spacing; greatly increasing the amount of backflow gas that could feed the ruptured location.

The examples provided are simplified, but illustrate the consequences of intervener's recommendations. Indeed, SoCalGas and SDG&E have dozens of locations similar to Attachment B. Attachment A, Figure A.1, already referenced under the discussion in 16-mile spacing, shows one such area of our pipeline with three major and several minor back-feeds which must be controlled to effectively depressurize that specific pipeline section. In short, the intervener's cost saving recommendation is technically unsound and will not allow us to isolate our pipelines in our stated timeline or at all in some instances.

b. Radio Technologies

DRA dismisses the proposed companion technology arguing that radio communication devices are distribution type assets. DRA dismisses this necessary and essential element without any technical discussion. SoCalGas and SDG&E stress the technical implication of DRA's removal of these devices is to weaken the communication system by not ensuring continuous communications during an event. A lack of continuous communication can result in slowed response time and increased risk. Communication devices are an essential element of the Valve Enhancement Plan and to limit the communication capability of the plan can result in ineffective rupture response.

c. ASV/RCV Dual Capability

Finally, TURN recommends the Commission reject SoCalGas and SDG&E's proposed conversion of ASV-only valves to dual functioning valves capable of ASV and RCV mode. SoCalGas and SDG&E reject this proposal as technically unsound.

The conversion to dual capability valves[8] will enhance SoCalGas and SDG&E's ability to route gas on its pipeline during an emergency and provide the necessary control and communication assets to support monitoring of pressure at 200 locations via our SCADA system. SoCalGas and SDG&E stand by their proposal to enable all mainline valves with dual control capability in order to provide continuous monitoring and improve the communication of valve information to control room operators for event management.

D. Conclusion

My testimony reaffirms the sound technical basis for our proposal and refutes the interveners' recommendations as yielding an unworkable valve plan. As such, SoCalGas and SDG&E request the Commission adopt SoCalGas and SDG&E's Valve Enhancement Plan in full.

IV. TECHNOLOGY PLAN

A. Purpose and Scope of Technology Plan

In its Rulemaking 11-02-019, dated February 25, 2011, the Commission directed pipeline operators to offer up a plan to improve pipeline safety which included a "comprehensive catastrophic risk assessment"[9] and efforts to "enhance overall public safety with regard to all subsurface utility facilities."[10]

[8] Although stated as "conversion from ASV to RCV," the more appropriate description is the conversion of ASV only valve to dual function one capable of ASV and RCV operation.
[9] R.11-02-019, p. 10.
[10] Id., p. 11.

SoCalGas and SDG&E, in the development of its technology proposal, have proposed a Technology Plan which would augment pipeline surveillance and leak monitoring. This proposed work includes:

- Installation of fiber-optic sensing on all future pipeline installations 12” and above in diameter to detect when near-vicinity activity may pose a risk to the integrity of a pipeline.
- Installation of approximately 2,000 continuous methane monitors to be retrofitted on all pipelines 20” and above routed in Location Class 3 and 4 areas and HCAs.
- Development of a Data Collection and Management System to interface with the above assets.

These proposed improvements address the most common threat to pipelines, 3rd party damage, along with a number of other pipeline risk factors.

B. Intervener Positions

DRA and TURN have reviewed and rejected the SoCalGas and SDG&E Technology Plan, arguing that the Technology Plan goes beyond the Commission’s intended scope and is unnecessary because SoCalGas and SDG&E operate safe pipelines under its current processes and programs. UWUA has also recommended rejection of our Technology Plan, arguing that the benefits associated with implementing the Technology Plan can be secured by expanding existing operations and maintenance programs via increases to the utility workforce.

C. SoCalGas and SDG&E Rebuttal

1. The Scope of the Commission’s Order and Rulemaking

DRA, TURN, and UWUA argue that the entirety of SoCalGas and SDG&E’s Technology Plan should be dismissed as outside the scope of the Commission’s Order. SoCalGas and SDG&E disagree with this interpretation of the scope.

As mentioned above, the Order Instituting Rulemaking orders SoCalGas and SDG&E to "enhance overall public safety with regard to all subsurface utility facilities."[11] In addition, D.11-06-017 ordered the utilities to "provide for interim safety enhancement measures, including increased patrols and leak surveys"[12] and consider "other such measures that will enhance public safety during the implementation period."[13] SoCalGas and SDG&E believe its Technology Plan will augment existing patrol and leakage survey activities and "enhance public safety;" clearly addressing the intent of the Order Instituting Rulemaking. As such, SoCalGas and SDG&E disagree with DRA, TURN, and UWUA's proposed dismissal of the Technology Plan.

2. No Need for Improvement

DRA concludes that because SoCalGas and SDG&E have operated, and continue to operate, safe pipelines, they should not pursue improvement as proffered in the Technology Plan. SoCalGas and SDG&E appreciate DRA's acknowledgement of our safe operating history, but disagree with DRA's assumption that prior success should prevent strategic and tactical programs aimed at continuous pipeline safety improvements. SoCalGas and SDG&E believe the spirit of the Rulemaking was for successful pipeline companies to look for ways to improve.

In furtherance of this, SoCalGas and SDG&E's Technology Plan is designed to provide more precise and timely information to our operations personnel and enhance our personnel's ability to pre-empt problems associated with 3rd parties who may not share SoCalGas and SDG&E's commitment to, or focus on, safety. Such operators, accountable for about 60%[14] of all pipeline ruptures based on industry statistics, can expose SoCalGas and SDG&E's pipelines

[11] Id., p. 11.
[12] D.11-06-017, p. 18.
[13] Id., p. 19.
[14] Reported Damages by Cause, for California Gas Transmission, 2002—2011, PHMSA's Significant Incident Files June 11, 2012, http://primis.phmsa.dot.gov/comm/reports/safety/AllPSIDet_2002_2011_CA.html?nocache=5620#_ngtrans

to immediate threats, and can sow the seeds of latent pipeline problems which may not show for several years. Early detection of such activity on large high pressure pipelines in populated areas is prudent and precisely what our Technology Plan addresses.

Finally, UWUA Witness Wood recommends rejection of the SoCalGas and SDG&E Technology Plan on an erroneous assertion that expanding existing leak survey and patrol programs can serve the same purpose.[15]

While UWUA's recommendations are discussed in detail in the Prepared Rebuttal Testimony of John Dagg, SoCalGas and SDG&E wish to stress that the proposed Technology Plan is intended to augment pipeline surveillance and leak monitoring beyond the capability of personnel walking the pipeline rights-of-way, not replace existing programs. Indeed, the very low concentrations of gas detectable with "boots on the ground" survey, while a batch-type process, is something we will not abandon. However, to assert that we can simply expand existing programs to achieve the same results as our Technology Plan is without foundation. For example, to try and provide *continuous leak survey* along our pipelines, comparable to our methane sensor plan (in near-real-time at 2,000 locations), would require a field force of approximately 10,000 added workers equipped with gas detection monitors. We don't believe this approach to be economically practical. As such, we ask the Commission to approve our proposal.

3. Fiber Optic Enhancement & Data Collection and Management System

TURN and DRA, drawing on CPSD's report, wrongly characterize SoCalGas and SDG&E's fiber optic enhancement proposal as being limited to 280 miles of PSEP-replaced pipe. Furthermore, DRA opines that SoCalGas and SDG&E, if it can justify its proposed

[15] UWUA Testimony (Wood), p. 10.

technology enhancements, should seek funding via the next General Rate Case, and not as part of the PSEP.

SoCalGas and SDG&E disagree. What is intended with this proposed installation of fiber optic monitoring is a new technology standard to apply to new or replaced high pressure pipelines with specific risk characteristic. This includes both pipeline work performed under the PSEP and future work which might be performed under normal General Rate Case funded programs. While the scope of funding requested in this Technology Plan is for the base monitoring system and for pipelines replaced under PSEP-approved plans, future pipeline work can and will be integrated into the proposed monitoring system.

In order to proceed with these enhancements, however, there is a need to develop the Data Collection and Management System to support monitoring. SoCalGas and SDG&E believe the installation of fiber optic cabling for monitoring should be preceded by, or performed in conjunction with, the development of the Proposed Data Collection and Management System, and that the cabling (or mesh, where applicable) should be installed when a pipeline section is exposed for construction. To do otherwise is illogical and not cost effective.

4. Delay Installation pending Cost-Benefit Analysis and Justification

TURN and DRA, drawing on CPSD's report, suggest SoCalGas and SDG&E defer its Technology Plan because SoCalGas and SDG&E have not provided sufficient justification or cost-benefit analysis.

SoCalGas and SDG&E offer that their cost estimates for the proposed technology work are bottom-up estimates with accuracy of plus or minus 10% where the field equipment is concerned and plus or minus 20% where the Data Collection and Management System is concerned. These are not gross or "dubious" estimates as suggested by TURN. A review of

Workpaper pages WP-IX-3-29 to WP-IX-3-36 provides detailed cost estimates based on discussions with vendors, secured equipment costs, and on our own internal history in routing pipelines through Location Class 3 and 4 areas and HCAs.

As for the benefits, SoCalGas and SDG&E offer that for less than 6% of the construction cost for associated new pipeline, we can equip pipelines with technologies which will help identify right-of-way intrusions and gas leakage in near real time. SoCalGas and SDG&E believe they have presented sufficient information to substantiate that pipelines are subject to damage from 3rd parties, and that these damages can result in either immediate and/or latent pipeline integrity issues. SoCalGas and SDG&E believe the inclusion of this technology responds to the Commission's Rulemaking and will cost-effectively enable SoCalGas and SDG&E to better monitor rights-of-way impacts or other events resulting in gas leakage.

5. Miscellaneous Revenues from Fiber Optics

TURN expresses concern that SoCalGas and SDG&E might use fiber installation to support Non-Tariffed Products and Services revenue stream via the leasing of "dark fiber" – using bandwidth and communication paths intended for pipeline monitoring for 3rd party commercial communication exploits.

This concern is baseless. The application of fiber optics is intended only to allow SoCalGas and SDG&E to identify a condition and activity before it turns into an emergency. Meaning, these fiber optic cables are installed with the express purpose of being disturbed or damaged by right-of-way intrusions. Regardless, SoCalGas and SDG&E have no such designs for added revenue from our Technology Plan, and simply aim to monitor our pipelines and rights-of-way for the reasons cited.

6. Reduction in Cost or Activity

TURN makes note that the fiber and/or methane detection will not be accompanied by reduction in monitoring activities and related costs associated with SoCalGas and SDG&E's current practices.

TURN is accurate in its interpretation that there is no offsetting reduction in existing leak survey activities associated with this proposed work. This is because the Technology Plan provides for continuous monitoring as an added level of vigilance to augment patrol and leak activities. It is not intended to replace existing leak and survey activities.

7. Cost Estimates

TURN, in aligning with CPSD's Technical Report on our Technology Plan, expressed concern that operating and maintenance cost for methane detection may be prohibitive.[16] Currently, the cost estimates in this Technology Plan reflect a 10% to 20% uncertainty and are based on detailed quotations from equipment manufacturers, pilot installation findings and projected labor costs for on-going maintenance. SoCalGas and SDG&E, however, acknowledge the cost concern and offer that some of these costs may come down if sensor technology improves over the next year or two. SoCalGas is currently evaluating sensors which hold this promise. As such, SoCalGas and SDG&E do not object to O&M costs for methane detection being revisited during their next general rate case and subsequent rate cases as we move through our Technology Plan implementation.

D. Conclusion

This testimony reaffirms that SoCalGas and SDG&E's Technology Plan is an appropriate effort to continuously improve pipeline safety. As such, SoCalGas and SDG&E's Technology Plan, as submitted, warrants approval by the Commission.

[16] TURN Testimony (Marcus), p. 27.

V. ENTERPRISE ASSET MANAGEMENT

A. Summary of Testimony

This testimony addresses TURN's and DRA's intervening testimony concerning SoCalGas and SDG&E's proposed EAMS Blueprint project and rebuts TURN and DRA's assertions focused on the need and scope of the EAMS Blueprint project:

- SoCalGas and SDG&E disagree with the assertions made by TURN and DRA which state that since SoCalGas and SDG&E have included an EAMS Blueprint in their PSEP filing, then their existing system must be inadequate and require remediation.
- SoCalGas and SDG&E disagree with the assertion by DRA and TURN that the EAMS Blueprint goes beyond the scope and objectives of Commission's Decision (D.11-06-017).

In addition, DRA and TURN assert that SoCalGas and SDG&E have not demonstrated that its existing applications and databases are inadequate. SoCalGas and SDG&E agree, the applications and databases that are currently in use by SoCalGas and SDG&E are effective and comply with regulatory requirements as well as applicable industry standards.

In the future, however, pipeline design, operational, and maintenance data will be available from a single graphical representation of a pipeline reducing the time required to analyze the impact of a specific condition or event. This integrated data will enable information to be made available to operations, engineering, field, and emergency response personnel in near real time.

B. Intervener Positions

TURN and DRA have differing views on the proposed EAMS Blueprint project. First, DRA and TURN's witness Long recommends its funding be denied. However, TURN's witness Marcus supports the "seed" funding and recommends:[17]

- Use of packaged software in developing the EAMS solution blueprint;
- Use of software solutions with longer life usability and adaptability; and
- Support the proposed EAMS solution blueprint costs be funded.

SoCalGas and SDG&E do not object to Marcus' recommendations and, consistent with Marcus' recommendation, SoCalGas and SDG&E are requesting funding only to identify PSEP EAMS requirements and develop a blueprint for a proposed solution. Then, once the EAMS blueprint is completed funding for implementation of the EAMS solution would be submitted for approval by the Commission under a separate regulatory review process. Furthermore, in addition to Marcus' recommendations, SoCalGas and SDG&E plan to leverage their investment in OpEx and existing system infrastructure as appropriate and prudent.

C. SoCalGas and SDG&E Rebuttal

1. EAMS Blueprint project is prudent and consistent with the Commission's decision and the lessons learned from San Bruno and not beyond the scope of the decision

DRA asserts that the Commission should reject SoCalGas and SDG&E's EAM blueprint request because it goes beyond the Commission's decision, D.11-06-017. As prudent operators, SoCalGas and SDG&E have taken note of what is unfolding in the industry. Lessons learned from San Bruno and the subsequent investigative reports make it prudent to develop new EAM capabilities that go beyond current industry standards and regulatory compliance requirements.

[17] TURN Testimony (Marcus), p. 28-29.

Our proposal is intended to collaboratively develop and blueprint these proposed capabilities, requirements, and solutions for subsequent consideration by the Commission.

The intent of the CPUC is clearly stated on page 18 of D.11-060-17, "We conclude, therefore, that all natural gas transmission pipelines in service in CA must be brought into compliance with modern standards for Safety." New and emerging requirements depend upon documenting, monitoring, analyzing, integrating and sharing data within SoCalGas and SDG&E and with regulators and first responders. When viewed in this context, we believe that the proposed EAMS blueprint activity is prudent and consistent with the Commission's decision and lessons learned as a result of San Bruno.

Furthermore, D.11-06-017 directs SoCalGas and SDG&E to ensure that asset information is readily accessible. SoCalGas and SDG&E agree and support the Commission's position that readily accessible asset information is a critical capability to enabling the Utilities' PSEP program. SoCalGas and SDG&E believe to accomplish this directive it should integrate electronic access to historical data, analysis results and reports based upon source data from many textual and geospatial files and databases. Ready access to this information by gas control, field operators and first responders will also improve our ability to respond if there is an event. We believe this approach is prudent and consistent with the Commission's and SoCalGas and SDG&E's goals for PSEP; improved integration and sharing meaningful information within SoCalGas and SDG&E and with the communities we serve.

2. EAMS Blueprint project is intended to enable new industry leading PSEP capabilities not remediate existing asset management and records management practices

SoCalGas and SDG&E have made and continue to make significant investments in pipeline asset management processes and systems. Existing processes and systems in use by SoCalGas and SDG&E comply with current regulatory requirements and accepted industry practices. The EAMS blueprint solution is not an activity designed to remediate inadequate governance, processes, and systems as asserted by TURN's Mr. Long and DRA's Ms. Phan or bring systems up to standards that should already have been met relating to accessibility of data and data governance.

To the contrary, SoCalGas and SDG&E current processes and systems meet regulatory requirements and applicable industry standards. The proposed PSEP EAM blueprint solution is not the result of SoCalGas and SDG&E's failure to create and retain the pipeline records necessary for the prudent operation of the gas transmission system. Nor is it intended to replace existing programs and processes. Rather, EAMS will leverage these existing assets to enhance SoCalGas and SDG&E's capabilities. For example, the investments made in OpEx provide a significant process and systems foundation that will be incorporated into EAMS. While OpEx was focused on improving operational efficiency for high volume repeatable work, EAMS will be used to extend and integrate the larger and more complex testing, pipeline replacement and advanced technology projects that are part of PSEP.

More generally, EAM is intended to respond to increased level of pipeline design, permitting and construction activities over the course of the next ten years in order to hydro-test and replace the pipelines covered by D.11-06-017. A large number of 3rd party contractors will be involved in performing this work. This will necessitate greater automation of construction information and work packages which must be done without compromising the quality of existing processes and data. Analyzing existing processes and technologies to verify that they will stand up to the significantly larger than normal volume of work and number of contractors and identifying needed enhancements is the prudent course of action as part of the EAMS blueprint activity. As such, the EAM is a prudent investment and the initiation of the EAM blueprint project during PSEP is appropriate.

D. Conclusion

SoCalGas and SDG&E's EAM proposal is a reasonable and prudent aspect of SoCalGas and SDG&E's PSEP, is responsive to the Commission's directives, is forward-looking, and should be approved.

ATTACHMENT A

VALVE ENHANCEMENT PLAN DRAWINGS

FIGURE A.1
16-MILE INTERVAL

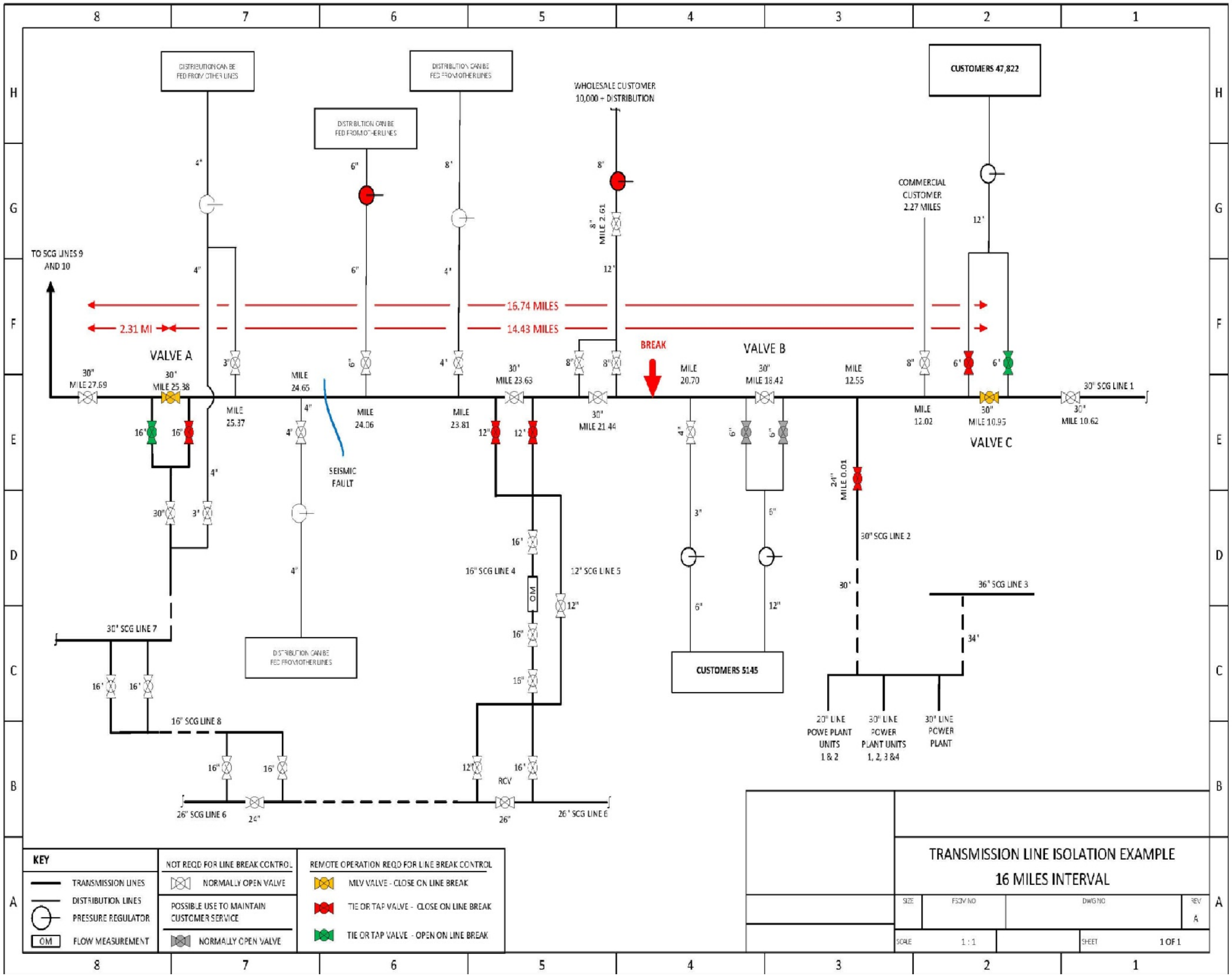


FIGURE A.2
8-MILE INTERVAL

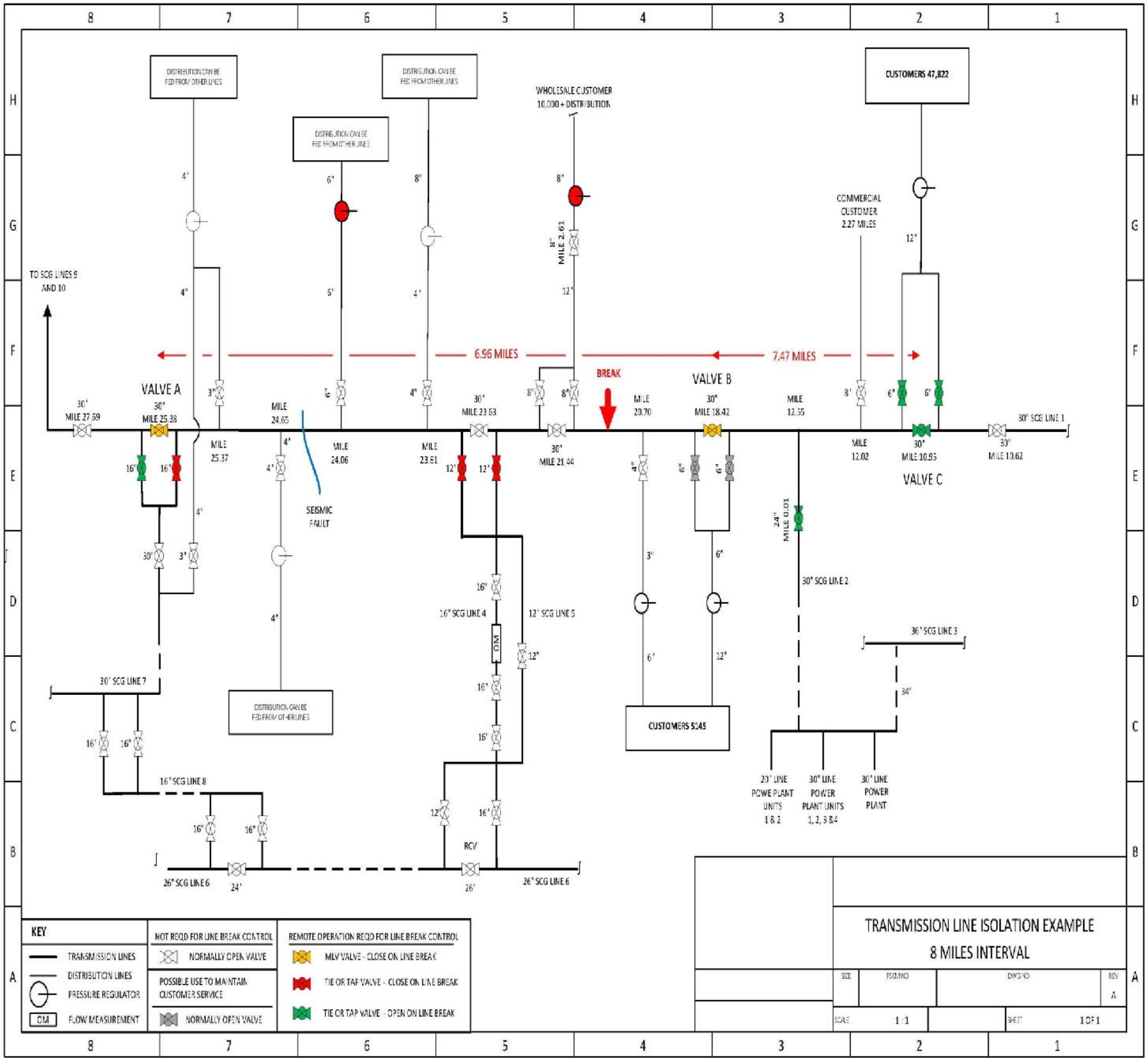
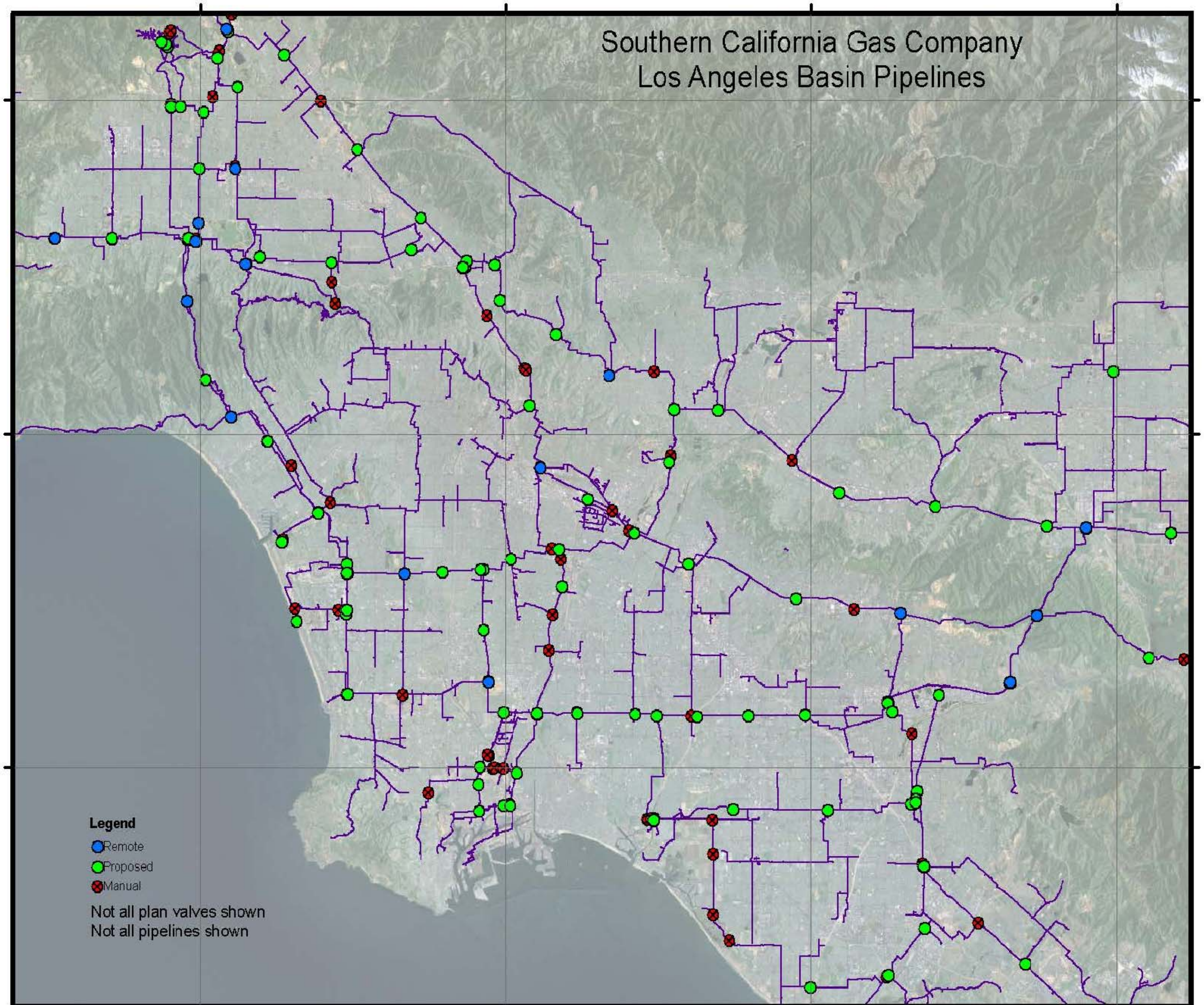


FIGURE A.3
PIPELINES WITH 16-MILE GRID



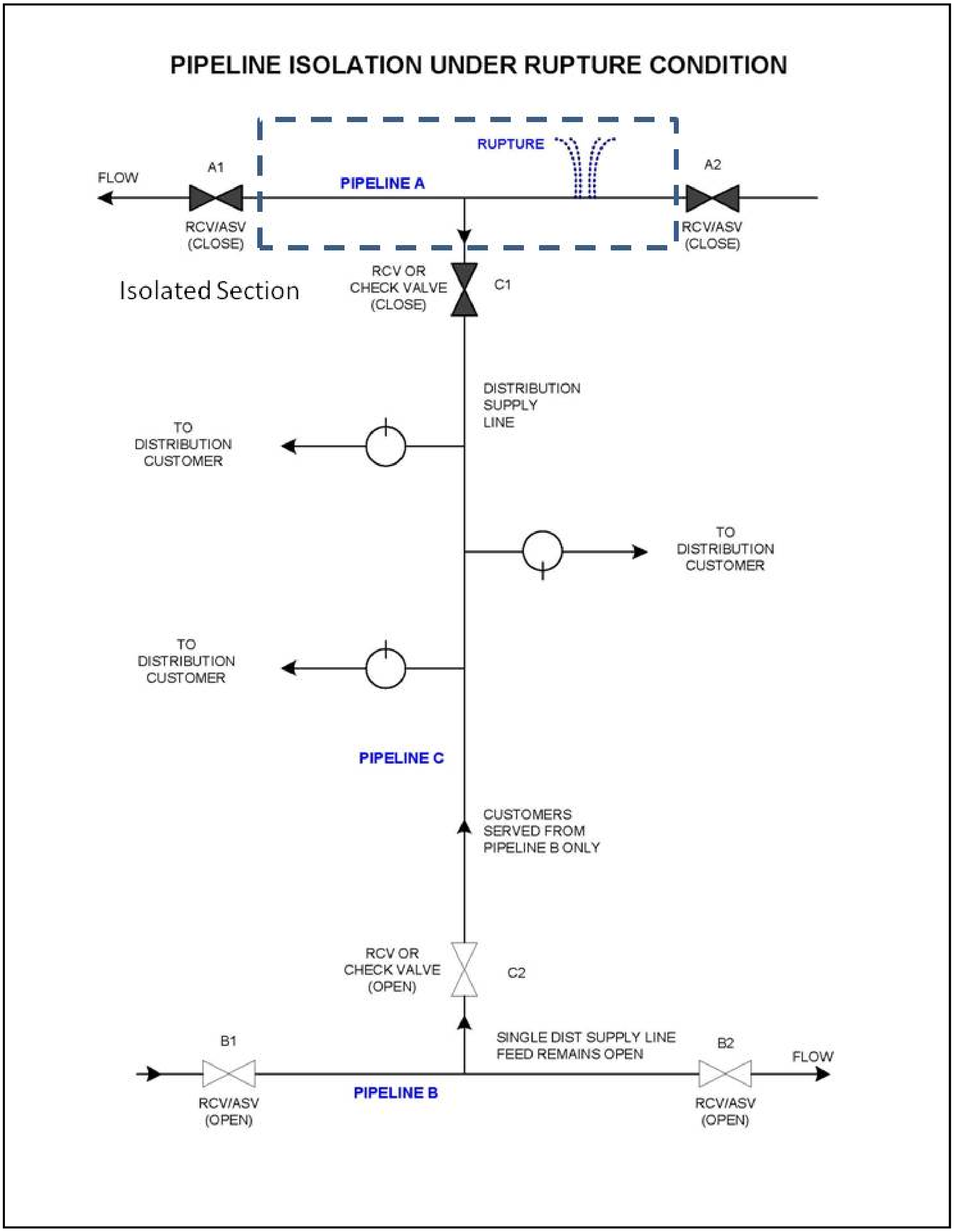
ATTACHMENT B

VALVE ENHANCEMENT – BACKFLOW

SCHEMATIC

Figure B.1

Pipeline Isolation Illustration



CHAPTER 12

ENHANCED OPERATIONS AND MAINTENANCE MEASURES

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PREPARED REBUTTAL TESTIMONY

OF JOHN L. DAGG

I. INTRODUCTION

The purpose of my rebuttal testimony is to clarify aspects of Southern California Gas Company's (SoCalGas) testimony and refute mischaracterizations and inaccuracies made by the Utility Workers Union of America (UWUA). This testimony will show that UWUA's proposals are either outside the scope of this proceeding or do not cost effectively and incrementally enhance the safety of the natural gas transmission system as required to achieve the Commission's pipeline safety objectives.

II. REBUTTAL OVERVIEW

In the testimonies sponsored by UWUA, UWUA proposes a number of modifications to how SoCalGas operates its system and conducts business, including:

- Interim measures applied to all pipelines;
- New permanent measures applied to all pipelines;
- New reporting mechanisms;
- New communications channels with the Commission; and
- Verification of utility progress on its implementation plan.

These UWUA proposals, however, are not appropriate for a review of SoCalGas' and San Diego Gas & Electric's Pipeline Safety Enhancement Plan, but are better addressed in the Pipeline Safety Rulemaking proceeding (R.11-02-019), which is addressing changes to natural gas pipeline safety regulations applicable to all California pipelines.

Beyond UWUA's more general proposals, UWUA also challenges many of the current state and federally mandated practices, standards, and requirements by which SoCalGas bases its operations and maintenance efforts and sets forth a number of proposed changes to these practices, standards, and requirements, to attempt to enhance safety during the implementation phase, including:

- Installing additional pipeline markers and checking markers every two weeks;
- Increasing pipeline patrol to two week intervals, on foot or by vehicle, without the use of aerial patrol;
- Modifying leak survey requirements to require surveys be conducted by walking the pipeline, eliminating truck-mounted equipment;
- Hiring more union welders to increase pipeline repair speed;
- Performing more frequent checks on the cathodic protection system; and
- Requiring quarterly valve inspection.

These UWUA recommendations, however, would not cost effectively or incrementally increase safety of the pipeline system. In addition, on page 10, line 9 of his testimony, Carl Wood recommends rejection of SoCalGas' proposed Technology Plan. Rebuttal to this recommendation is presented in the Prepared Rebuttal Testimony of Joe Rivera.

III. UWUA'S CONCERNS ARE MORE APPROPRIATELY ADDRESSED IN THE PIPELINE SAFETY RULEMAKING PROCEEDING

SoCalGas believes UWUA's concerns are not directly related to SoCalGas and San Diego Gas & Electric's Pipeline Safety Enhancement Plan (PSEP), but deal with the Commission's operations and maintenance requirements. These UWUA proposals include: Interim measures applied to all pipelines; New permanent measures applied to all pipelines; New reporting mechanisms; New communications channels with the Commission; and Verification of utility progress on its implementation plan. SoCalGas believes the appropriate avenue to address these concerns is in the Commission's Pipeline Safety Rulemaking proceeding (R.11-02-019), which already is addressing changes to natural gas pipeline safety regulation applicable to all California pipelines. In fact, the Rulemaking

Order clearly demonstrates the Commission's intention to consider the issues raised by UWUA:

> This rulemaking will consider what aspects of the Commission's regulation of natural gas transmission and distribution pipelines should change, e.g., siting, maintenance, inspections, best operating practices, ratemaking, and safety audits.[1]

These UWUA proposals are beyond the scope of the Implementation Decision, which aimed to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipelines that have not been pressure tested and implementing additional enhancements during the implementation phase, and are more appropriately addressed in R.11-02-019. In short, UWUA raises a number of issues that are simply inappropriate for a proceeding focused on a review of SoCalGas' and SDG&E's Pipeline Safety Enhancement Plan.

IV. LOCATE AND MARK ACTIVITIES

UWUA proposes installing additional pipeline markers and checking markers every two weeks. SoCalGas believes that its current locate and mark efforts are appropriate and that this increased locate and mark activity is unnecessary and not cost effective.

SoCalGas' current locate and mark efforts meet or exceed applicable requirements. First, SoCalGas' current line marking is done consistent with Title 49 of the Code of Federal Regulations (C.F.R.) section 192.707, which requires line markers be placed as close as practical over the pipeline. Next, as discussed below in the section on patrols, PSEP pipeline segments are currently being patrolled at two month intervals (i.e., bi-monthly) as an interim safety measure. During these regular patrols SoCalGas employees are trained to engage in additional line marker inspections. Finally, while there are no spacing

[1] R.11-02-019, p. 6.

requirements in Title 49 of the C.F.R., SoCalGas policy states spacing can vary depending upon conditions, but normally is not greater than the line of sight.

Beyond these activities, SoCalGas has also proactively sought ways to enhance its locate and mark activities by utilizing bilingual signs and markers and engaging with the public to reinforce the importance of the 8-1-1 One Call Program discussed below. Consistent with these efforts, SoCalGas employees are trained and expected to repair/replace pipeline markers or issue a work order for follow-up during the performance of other work near pipelines or along the right-of-way.

Despite SoCalGas' exceptional locate and mark efforts, however, damage to pipelines still does occur as a result of third party intrusion on SoCalGas' right-of-way. In this regard, SoCalGas agrees with UWUA that locate and mark is an important function, and prevention of damage by third party excavators is critical.

SoCalGas, however, disagrees with UWUA's statement regarding locate and mark being more important for older pipelines due to their older coating. Admittedly, SoCalGas does consider the age of the pipeline when the pipelines experience surface loading, pipeline free-spanning, and excavation and backfilling operations. Regardless, SoCalGas endeavors to treat all pipelines equally as far as locate and mark activities are concerned because both old and new pipelines are susceptible to third party damage. SoCalGas has been involved in industry studies that have concluded that the two most effective methods of preventing third party damage to gas pipelines are California One Call Law, California Government Code 4216, which requires all excavators to call 8-1-1 for all underground work so the line can be accurately located, and, for transmission pipelines, continuous stand-by during the excavation and backfill operations. In efforts to enhance the effectiveness of these methods, SoCalGas conducts excavator workshops and communication campaigns to remind the public, especially excavators, of the importance of calling 8-1-1 before they dig. Pipeline markers in themselves, however, are not a deterrent but a reminder that an important or noteworthy pipeline is in the area, and to call before digging.

Indeed, experience has demonstrated that, despite SoCalGas' best efforts, markers are not as effective as SoCalGas would hope or expect. In fact, all of our most recent dig-in events on transmission lines had pipeline markers within 5 to 40 feet of the damage location. Unfortunately, locate and mark activities are ineffective when third parties ignore markers or fail to assess their surroundings prior to digging. As such, UWUA's locate and mark proposals offer a costly solution that does little to improve pipeline safety.

V. INSPECTION AND PATROL

UWUA accuses SoCalGas of lacking clear and adequate procedures and policies regarding employee inspection and patrols and proposes that pipelines be patrolled at two week intervals, on foot or by vehicle, without the use of aerial patrol. SoCalGas believes that its current inspection and patrol efforts, including increased patrols during the implementation phase, are prudent and that UWUA's increased inspections and patrols are an unnecessary and costly proposal that fails to leverage the abilities of aerial patrol.

SoCalGas' current inspection and patrol policies meet or exceed Title 49 of the C.F.R. and are appropriate for the system we operate. Currently, SoCalGas patrols its pipelines at highway and railroad crossings and all other locations annually, semi-annually or quarterly, in accordance with 49 C.F.R. section 192.705. In addition, in between patrols, there are many other opportunities during normal pipeline operation and maintenance activities for employees to observe conditions along the pipeline. SoCalGas' inspection and patrol policy requires employees: Observe surface conditions of right-of-way; Report conditions of leakage, missing or damaged line markers; Report conditions affecting the safety of, or access to the pipeline, e.g., landslides, subsidence, erosion, damaged nearby structures, excess vegetation, etc.; Report right- of- way encroachments; and Report development within 220 yards of the pipeline. Beyond these general requirements, SoCalGas also has clear written policy regarding how to respond should employees discover and report construction or other types of soil disturbing activity in the transmission or distribution right-of-way.

SoCalGas employees who discover intrusion on SoCalGas' right-of-way are instructed to inform their supervisor who will contact the appropriate Region and Land & Right of Way departments to determine if the encroachment poses an unreasonable interference with the continued operation and maintenance of the facility or is prohibited by SoCalGas' existing rights. If the encroachment poses an unreasonable interference, the Region and Land & Right of Way and legal departments will determine the best approach to having the encroachment mitigated. If the encroachment does not pose an unreasonable interference, Land & Right of Way, with Region input, is responsible for negotiating an agreement to govern the encroachment.

Next, UWUA argues that aerial patrol is ineffective and there is a need to increase foot inspections and patrols.

Again, however, SoCalGas' current inspection and patrol policies comply with Title 49 of the C.F.R. and are appropriate for the system we operate. Indeed, as per 49 C.F.R. section 192.705, aerial patrol is an acceptable method of patrol. Consistent with this, SoCalGas does utilize a helicopter to patrol one pipeline that is difficult to access by vehicle or on foot. A SoCalGas pipeline employee rides in the helicopter to conduct the patrol. Additionally, fixed wing aircraft are used in aerial patrols to supplement ground patrols, and provide additional observation of the pipelines. These aerial patrollers are operator qualified to perform their tasks and UWUA has provided no evidence that demonstrates any deficiency in patrols performed by aerial patrollers. To the contrary, these aerial patrols have proven effective at identifying landslides, erosion, subsidence, maintenance needs, grading, excavating, surveying, construction encroachment, or other activities indicative of development or work around the pipelines. In addition, aerial patrols are used to further enhance patrol activity during seasonal agricultural activities, such as field "ripping," to provide additional observation. Consistent with the policies discussed above, if any of these items are observed, they are reported to SoCalGas for follow-up on the ground.

Finally, SoCalGas wishes to clarify certain inaccurate statements made in UWUA's testimony related to inspections and patrols.

First, on page 6, line 28 of Robin Downs' testimony, UWUA states: "SoCalGas has implemented two-week patrol intervals on pipe that is subject to the PSEP on an interim basis." For clarification, SoCalGas is performing pipeline patrol on PSEP pipelines at two month intervals (i.e., bi-monthly) as an interim measure, during implementation of PSEP as directed by Decision 11-06-017.

Next, on page 9, line 29 of Carl Wood's testimony, UWUA states: "…these measures are being carried out through increased overtime and/or diversion of employees from other tasks…" For clarification, it is true increased overtime is being used, but employees are not being diverted from other tasks. In other words, this work is incremental to our regular work, and does not replace any regular work.

In conclusion, UWUA's inspection and patrol proposals are costly, unnecessary, and ignore the current propriety and effectiveness of SoCalGas' inspection and patrol policy and efforts.

VI. LEAK SURVEY AND REPAIR

UWUA's leak survey and repair proposal recommends additional, on foot, leak surveys and faster leak repairs. SoCalGas believes that its current leak survey and repair efforts are prudent and that UWUA's proposal is unnecessary and not cost effective.

SoCalGas' current inspection and patrol policies meet or exceed Title 49 of the C.F.R. and are appropriate for the system we operate. Currently, SoCalGas policy meets 49 C.F.R. section 192.706 requirements that leak survey be conducted at intervals not exceeding fifteen months, but at least once each calendar year. While Title 49 of the C.F.R. does not require the use of leak detection equipment on an odorized pipeline, SoCalGas chooses to use leak detection equipment to survey many sections of its pipelines as an extra measure. For example, SoCalGas currently utilizes the truck mounted Heath Consultants Optical Methane Detector in many areas where a truck can be driven over the pipeline. Although the Optical Methane Detector will read methane down to 1 part per million, SoCalGas uses it as a search tool and does not use it to accurately measure a gas concentration. If a leak is detected, the employee will park the truck and investigate the leak on foot. If needed, a follow-up work order is generated. SoCalGas has also tested new aerial leak sensor technology, but it has not been adopted as a regular survey method.

Next, SoCalGas agrees with UWUA when it states leaks on a transmission line must be addressed quickly. When a hazardous leak is found on a transmission line, SoCalGas initiates immediate and continuous action until the situation is made safe and the immediate threat is eliminated. UWUA, however, states that transmission leaks may go unrepaired for months.[2] While SoCalGas acknowledges that minor nuisance leaks on fittings, bolted connections, or pinhole leaks on buried pipe may occur, these leaks are non-hazardous, have nothing to do with the strength or integrity of the pipe, do not pose any safety risk to the public, and are addressed per company policy.

Finally, UWUA states permanent repair should be made as soon as operating conditions permit safe welding practices and SoCalGas should employ a sufficient number of qualified welders to perform permanent repairs on that schedule. SoCalGas utilizes a sufficient number of both qualified employees and qualified contract welders to perform repair work in a timely manner. The engagement of qualified contract welders is an appropriate means by which SoCalGas can prudently maintain its pipeline system and avoid permanently staffing more welders than are necessary during less busy months.

In conclusion, UWUA's proposal does not offer cost effective and incremental enhancement to SoCalGas' current leak survey and repair policy and efforts.

VII. CATHODIC PROTECTION

UWUA cathodic protection proposal recommends that "CP on all transmission lines should be checked and corrected at least eight (8) times per year. The PHMSA standard is six (6) times per year."[3] SoCalGas believes that its current cathodic protection policies are prudent and that UWUA's proposal is unnecessary and not cost effective.

Currently, SoCalGas goes beyond the minimum requirements of Title 49 of the C.F.R. For example, in addition to the 6 rectifier checks required by 49 C.F.R. section

[2] In Data Request SoCalGas-TCAP-PSEP-DR-01-07 UWUA was asked to substantiate this claim but was only able to provide instances of a known and monitored minor bolted connection leak, a known and repaired minor valve flange leak, and a known and repaired minor valve leak on a distribution line. None of which were deemed hazardous.

[3] UWUA Testimony (Downs), p. 8.

192.465, SoCalGas is nearing completion of a project to install cellular communication devices on all its Transmission Department rectifiers. This technology will allow employees to check the status of the rectifier on a web page from any internet connection. The system will also send an alarm if it detects an issue with rectifier operation. This technology will allow SoCalGas to provide ***continuous*** monitoring of one of the most important components of the cathodic protection system. In addition, the SoCalGas Transmission Department uses IBM Cognos, a web-based software application to analyze, query, and produce reports from cathodic protection data in the company's Computerized Maintenance Management System. This tool helps analyze data and monitor cathodic protection effectiveness.

Next, UWUA argues that delays in correcting cathodic protection conditions are related to a lack of employees. This is simply not the case. Any lengthy delays in the correction of cathodic protection conditions have nothing to do with the number of employees, but the time required to obtain permits for remedial or replacement work. When these conditions exist, SoCalGas implements contingencies such as turning up other nearby rectifiers or bonding other pipelines over to enhance a pipeline's cathodic protection. These efforts offer protection on the pipelines until permits to perform the remedial work can be obtained.

Finally, UWUA asserts that due to a records issue on Line 1001, the cathodic protection system was not checked for a considerable period and remained broken for some time. SoCalGas has found no evidence to support UWUA's statement. SoCalGas checked its records going back as far as 1993 and all maintenance was found to have been completed in a timely manner per policy.

In conclusion, UWUA's proposal is unnecessary, not cost effective, and mischaracterizes SoCalGas' cathodic protection policy and practices.

VIII. VALVE MAINTENANCE

UWUA suggests that all valves should be inspected quarterly. SoCalGas agrees that valve inspections are important and currently engages in appropriate valve inspection efforts and policy, which comply with Title 49 of the C.F.R.

SoCalGas policy and Title 49 of the C.F.R. prioritize valve inspections based on valve function to ensure the most important valves receive the attention they need to maintain system safety. For example, SoCalGas policy complies with 49 C.F.R. section 192.745, which requires each transmission line valve that might be required during an emergency to be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year. SoCalGas policy also requires that, when a valve is found inoperable, SoCalGas takes prompt remedial action to correct the valve or designate an alternative valve. SoCalGas finds this interval and policy appropriate, and in its experience sees no benefit to additional valve maintenance activities. Moreover, in addition to the valve maintenance required by Title 49 of the C.F.R., valves are operated during normal pipeline operations, shutdowns, and pigging operations. These operations provide additional opportunity to verify that valves are operating properly.

Next, UWUA suggests that if, during scheduled maintenance, a valve is found in need of additional repair, the maintenance work order should remain open until all issues are resolved. SoCalGas policy states that if in the course of maintenance activity additional work beyond the scope of the original maintenance work order is identified, a compliance corrective work order is to be created to accomplish the extra work, and the original maintenance work order is to be closed. If a critical valve is found to be inoperable, an alternative valve or valve configuration is designated until the inoperable valve is returned to service. When valves, actuators, or controllers are found to have problems, those problems are corrected by repair or replacement at the time of inspection or during subsequent corrective work. SoCalGas believes this policy to be appropriate and effective in maintaining valve function and promoting system safety.

In conclusion, UWUA's proposal is unnecessary, and ignores the current propriety and effectiveness of SoCalGas' valve maintenance policy and efforts.

IX. SUMMARY AND CONCLUSION

UWUA's proposals are either outside the scope of this proceeding or are costly and do not significantly enhance pipeline safety, thereby do not assist in achieving the Commission's pipeline safety objectives. For these reasons and the aforementioned specifics, the Commission should reject the UWUA's recommendations.

This concludes my prepared rebuttal testimony.

CHAPTER 13

INTERRUPTION AND RESERVATION

CHARGE CREDITS

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PREPARED REBUTTAL TESTIMONY

OF STEVEN WATSON

I. PURPOSE

The purpose of my rebuttal testimony is to address the recommendations made by R. Thomas Beach on behalf of the Southern California Indicated Producers and Watson Cogeneration (SCIP/Watson) that SoCalGas and SDG&E provide the following credits to certain customers as a result of safety-related work:

- A local transmission interruption credit for inadequate notice that is fully funded by SoCalGas and SDG&E shareholders; and
- A reservation charge credit to firm Backbone Transmission Service (BTS) customers that is funded fifty percent (50%) by SoCalGas and SDG&E shareholders.

Mr. Beach has also presented a related proposal that customers operating critical energy infrastructure receive at least six months notice before their service is curtailed for safety-related work. That particular recommendation by Mr. Beach is addressed by Mr. Phillips.

II. MR. BEACH'S CREDIT PROPOSALS ARE NOT APPROPRIATE FOR PHASE 1 OF THIS PROCEEDING

Mr. Beach's proposed credits do not address the primary focus of the first phase of this proceeding -- namely, the proper types and levels of utility expenditures to enhance pipeline safety. Rather, Mr. Beach's credit proposals and related testimony focus on the *allocation* of those costs. Cost allocation is a secondary issue that belongs in the second phase of this TCAP proceeding. Mr. Beach's credit proposals should be considered in Phase 2, not here.

III. MR. BEACH'S CREDIT PROPOSALS ARE UNREASONABLE AND UNFAIR

Mr. Beach's testimony regarding cost allocation can be summed up rather simply -- make utility shareholders, rather than ratepayers, bear most of the costs that arise from the

Commission’s recent new pipeline safety directives. Mr. Beach’s proposals are ill-conceived variations of this simple theme. Mr. Beach’s various proposals to put shareholders at risk for pipeline safety costs seem to be premised on the following incorrect premise: “Ratepayers are being asked to assume an extraordinary burden, in a very short period of time, to bring the safety of the state’s pipeline system up to a reasonable standard, after what appears to be years of underinvestment in safety . . ..”[1] There has never been an “underinvestment in safety,” as Mr. Beach states, and our proposed PSEP program is not designed to bring our systems up to a “reasonable standard.” Our pipeline systems already meet or exceed the standards that existed prior to the Commission’s new safety requirements. The truth of the matter is that ratepayers are being asked to pay for reasonable investments to increase their safety in accordance with new, higher pipeline safety standards ordered by the Commission.

Mr. Beach proposes that SoCalGas and SDG&E provide backbone reservation charge credits to customers when their backbone transmission service is disrupted by pipeline safety work, 50% of which would be funded by utility shareholders.[2] Mr. Beach’s proposal would undermine the basic premise of the FAR decisions that Sempra shareholders would not be at-risk for the provision of backbone transmission services.[3] Applying the 50/50 sharing mechanism of the negotiated PG&E Gas Accord to SoCalGas and SDG&E for any element of backbone transmission costs, including disruptions caused by maintenance for pipeline safety enhancement, is not valid. SoCalGas and SDG&E could provide backbone reservation charge credits under the current 100% balancing regime of the FAR decision, however, such credits would simply have to be recovered as backbone cost increases in future periods from all firm

[1] SCIP/Watson Testimony (Beach) at p. 20.
[2] SCIP/Watson Testimony (Beach) at p. 23.
[3] *See* D.06-12-031, mimeo., at 139 and 142 (Conclusion of Law No. 9 and Ordering Paragraph No. 6); D.11-04-032, mimeo., at 81 and 84 (Ordering Paragraph Nos.2 and 14).

backbone transmission rights holders -- potentially including those who originally received the "credits." Such an approach would be counterproductive and administratively cumbersome. Credits are not currently applied to backbone rights holders when other maintenance events occur, including pipeline integrity work, and credits should not be applied for maintenance events specifically related to Commission-mandated pipeline safety requirements.

Today, very few customers actually hold long-term backbone capacity that would be negatively affected by SoCalGas' and SDG&E's planned pipeline work. Moreover, customers such as Mr. Beach's clients could easily avoid paying for firm backbone capacity that could be interrupted by PSEP work by simply not purchasing capacity at any receipt point that would be affected. In addition, Mr. Beach fails to mention the flexibility SoCalGas provides its firm backbone shippers. If maintenance affects a particular receipt point, firm rights owners have the ability to move their firm capacity to different receipt point that is not affected, to the extent capacity is available at the requested receipt point. Given that SoCalGas currently has a limited number of firm capacity holders at any of its receipt points, this would be a reasonable option for Mr. Beach's clients and other firm rights holders temporarily affected by PSEP work.

The issue of BTS credits was a subject that was decided by the Commission in D.11-04-032. In that proceeding, the joint proposal was affirmed by the Commission, and BTS credits were specifically rejected because the Commission believed that credits would encourage shippers to purchase excess BTS, causing capacity constraints and scheduling issues.[4] The Commission should not revisit this particular proposal in this proceeding.

Mr. Beach also proposes a local transmission interruption credit of $2.50/dth (capped at $25 million/year) that shareholders should fund in the event that noncore customer service is interrupted due to pipeline integrity work for which the customer has not received at least 30

[4] *See* D.11-04-032, mimeo., at 48.

days notice.[5] This proposal would be unfair and potentially counterproductive to the safety-related objectives of the utilities, the Commission, and the state.[6] SDG&E and SoCalGas have explained that we will endeavor to give affected customers at least 30 days notice of upcoming pipeline-related work that will affect their service, but we should not be financially penalized if we are unable to provide this much notice. If a pipeline-related safety issue arises that needs to be dealt with more quickly than 30 days hence, SoCalGas and SDG&E should be permitted to do the work without financial penalty, and we should not be put in the position of having to decide whether to put off safety-related work to avoid a financial penalty. Likewise, the Commission should not establish a policy for SoCalGas, SDG&E, or any other utility that gives us a strong incentive to put off necessary safety-related work. Mr. Beach's proposed local transmission interruption credit is a prime example for a perverse incentive that could make California less safe.

SoCalGas and SDG&E already have tariffs that establish the relationship between the utilities and their noncore customers with respect to repairs and maintenance work. These tariffs (Rule 30 – Transportation of Customer-Owned Gas) provide that the utilities have the right, without liability, "to interrupt the acceptance or redelivery of gas whenever it becomes necessary to test, alter, modify, enlarge or repair any facility or property comprising the Utility's system or otherwise related to its operation."[7] These long-established tariff provisions also provide to that "[w]hen doing so, the Utility will try to cause a minimum of inconvenience to the customer.

[5] SCIP/Watson Testimony (Beach) at p. 26.
[6] As the Legislature recently explained in Public Utilities Code Section 963(b)(3), "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."
[7] SoCalGas Rule 30(E)(2); SDG&E Rule 30(E)(2).

Except in cases of unforeseen emergency, the Utility shall give a minimum of ten (10) days advance written notice of such activity."[8]

In addition, SDG&E has a Service Interruption Credit (SIC) provision which provides that SDG&E may be required to provide a SIC of $0.25/therm if SDG&E interrupts service to conduct non-emergency scheduled maintenance without providing at least 30 days prior written notice of the scheduled interruption.[9] This provision further provides as follows:

> The utility shall take all reasonable steps to minimize the duration of such scheduled maintenance interruptions and to reroute the flow of natural gas to eliminate any service interruptions that would otherwise occur due to such maintenance.
>
> The utility shall consult with the customer in scheduling any such maintenance interruptions and shall use reasonable efforts to schedule such maintenance to accommodate the customer's operating needs and to continue same only for such time as is necessary, including any agreed upon adjustments to the scheduled date for maintenance as reasonably necessary in light of unforeseen occurrences affecting the customer and/or the utility.[10]

Given all of these existing tariff provisions governing the rights and relationship of the utilities and their customers with respect to pipeline testing, repairs, and replacement work, there is simply no need for the additional provisions proposed by Mr. Beach.

Additionally, since hydrotesting a pipeline would take the line out of service for a much longer time than replacing it, both of Mr. Beach's proposals could provide SDG&E and SoCalGas with a perverse incentive to replace pipe in order to minimize the length of time the line is out of service. The test versus replace decisions of SoCalGas and SDG&E should be made in accordance with the criteria and consultation process proposed by SoCalGas and SDG&E (as described by witness Rick Phillips). This decision should not be influenced by the

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[8] *Id.* Note that SDG&E's Rule 30 tariff refers to the "Utility System Operator" rather than the "Utility" in this particular sentence, but otherwise the wording is identical.

[9] *See* SDG&E Rule 14(O)(2). SoCalGas used to have a similar SIC provision, but that provision ended in 2003. *See* SoCalGas Rule 23(K) (the provision only applied during the "ten-year period beginning on the implementation date of the CPUC's Capacity Brokering Rules.")

[10] SDG&E Rule 14(O)(2).

existence of a crediting mechanism that would give SoCalGas and SDG&E an artificial incentive to pressure test rather than replace lines.

This concludes my prepared direct testimony.

CHAPTER 14

COST RECOVERY AND REVENUE REQUIREMENTS

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PREPARED REBUTTAL TESTIMONY

OF EDWARD J. REYES

I. INTRODUCTION

The purpose of this testimony is to respond to issues raised by certain intervenors in testimony on June 19, 2012,[1] about the proposed Pipeline Safety Enhancement Plan (PSEP) cost recovery and revenue requirement approaches presented by Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) in our direct testimony.

The cost recovery topics I will address include the following:

- Two-way balancing account treatment for PSEP costs;
- Timing of recovery of PSEP-related revenue requirements;
- An expedited advice letter process for changes in PSEP funding levels;
- Our proposed PSEP surcharge; and
- Our proposed treatment of robotics royalties.

The revenue requirement issues I will address include the following:

- AFUDC methodology and percentages for PSEP assets;
- Treatment of non destructive examination (NDE) costs; and
- Treatment of project overhead loaders.

[1] These particular intervenors are the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), the Southern California Generators Coalition (SCGC), and Southern California Indicated Producers/Watson Cogeneration Company (SCIP/Watson).

II. COST RECOVERY ISSUES

A. Two-Way Balancing Account Treatment

DRA and SCIP/Watson recommend one-way balancing account treatment for PSEP costs, rather than the two-way balancing account treatment proposed by SoCalGas and SDG&E.[2] SCIP/Watson also recommends that the Commission adopt one-way balancing account treatment for Transmission Integrity Management Program (TIMP) costs.[3] These recommendations should not be adopted by the Commission.

A two-way balancing account mechanism is necessary to ensure that reasonable costs incurred in implementing the new pipeline-related requirements established by the Commission can be recovered from ratepayers. The two-way balancing account provides flexibility for SoCalGas and SDG&E to recover, on an annual basis as necessary, any undercollections that may be incurred due to a shortfall of revenues collected through the PSEP surcharge compared to the actual costs that are necessary to implement the PSEP. Conversely, ratepayers may also benefit if overcollections materialize where revenues are in excess of actual PSEP costs. This two-way mechanism ensures that ratepayers pay for the reasonable costs of SoCalGas and SDG&E's PSEP, and that all parties are trued-up in a timely manner for any cost/revenue differences.

One-way balancing account treatment is not a preferred approach as this would result in SoCalGas and SDG&E's shareholders bearing the cost of necessary PSEP safety-related expenditures in excess of an authorized budget/cost cap approved by the Commission. A one-way balancing account approach for PSEP also would not provide SoCalGas and SDG&E with appropriate safety-related incentives. This issue was discussed in the Report

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[2] DRA Testimony (Phan) at p. 25; SCIP/Watson Testimony (Beach) at p. 3.
[3] SCIP/Watson Testimony (Beach) at p. 3.

of the Independent Review Panel which found that "one-way balancing accounts create a perverse incentive for the utility to spend exactly as the stakeholders have negotiated – spending no less or more than authorized for a given activity."[4] The report also concludes that "it is not clear whether one-way balancing account associated with a federally mandated integrity management program improves the incentive for prudent utility decision-making regarding safety."[5] SoCalGas and SDG&E should not be put in the position of having to choose between reasonable and necessary pipeline-related expenditures that exceed PSEP budgets and a shareholder penalty for undertaking necessary safety-related improvements. The Legislature has unambiguously determined that "[i]t 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."[6] Two-way balancing of PSEP costs achieves this objective. One-way balancing of PSEP costs would not.

Regarding Mr. Beach's recommendation for one-way balancing account treatment for SoCalGas and SDG&E's TIMP, this is not the appropriate proceeding for any of us to be discussing the treatment of TIMP costs. TIMP costs were addressed in SoCalGas' and SDG&E's 2012 General Rate Case (GRC) applications, and will likely be addressed in future GRC applications. If SCIP/Watson or Mr. Beach wish to make recommendations with respect to TIMP costs in our future GRC proceedings, they are certainly free to do so.

B. Timing of Recovery of PSEP Revenue Requirements

SCGC argues that the Commission should not allow recovery of replacement project revenue requirements until the project is "used and useful" and recommends that the

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[4] Report of the Independent Review Panel – San Bruno Explosion issued on June 8, 2011, Section 7.2 at page 109.
[5] *Id*. Section 7.3 at page 110.
[6] Public Utilities Code Section 963(b)(3).

proposed PSEP cost recovery account should be maintained by subaccounts to detail expense activities separately from the revenue requirement associated with capital projects.[7] SoCalGas and SDG&E disagree with each of these recommendations.

The Commission regularly authorizes utilities to recover revenues associated with capital projects on a forecast basis, before the projects are considered "used and useful." In fact, our proposed collection of forecasted PSEP capital revenue requirements is similar to the way various other incremental projects have been funded, for example, SoCalGas' Advanced Meter Infrastructure (AMI) and SDG&E's AMI projects,[8] SDG&E's Cuyamaca Peak Energy Plant,[9] and SDG&E's Solar Energy Project.[10]

Funding for PSEP costs prior to the time that PSEP assets are considered "used and useful" is consistent with the Commission's direction that SoCalGas and SDG&E, to the extent possible, not create large PSEP-related undercollections that could have a significant rate impact to customers. This guidance was further emphasized in connection with the Commission's approval of SoCalGas and SDG&E's request to establish a memorandum account where SoCalGas and SDG&E were advised that the Commission "will expeditiously consider any motion to adopt an interim rate, subject to refund, based on the current authorized cost allocation and rate design to avoid a large under collection for Safety Enhancement."[11] SoCalGas and SDG&E were further warned that "that they have an

[7] SCGC Testimony (Yap) at pp. 28 and 30.
[8] SoCalGas' AMI Project approved pursuant to Commission D.10-04-027 and incorporated in SoCalGas Preliminary Statement, Part V., Regulatory Accounts – Balancing. SDG&E's AMI project approved pursuant to Commission D.07-04-043, modified in D.11-03-042 and incorporated in SDG&E's Electric and Gas Preliminary Statements, Section II. – Balancing Accounts.
[9] Approved pursuant to Commission D.11-12-002 and incorporated in SDG&E Electric Preliminary Statement, Section III. - Memorandum Accounts.
[10]Approved pursuant to Commission D.10-09-016 and incorporated in SDG&E Electric Preliminary Statement, Section II. - Balancing Accounts.
[11] Assigned Commissioner Ruling and Scoping Memo issued on February 24, 2012, at p. 7.

obligation to avoid accumulating a large under collection in the memorandum accounts and imposing a burden on ratepayers later to amortize that balance."[12] In response to this ruling, SoCalGas and SDG&E filed a motion for interim recovery for PSEP costs recorded in their Pipeline Safety and Reliability Memorandum Accounts.[13] Therefore, because SoCalGas and SDG&E should not have to distinguish between PSEP capital expenditures and O&M expenses, there is no reason to maintain subaccounts within the PSEP Cost Recovery Accounts, as SCGC proposes.

1. Review of PSEP Expenditures

DRA opposes the process for reviewing PSEP-related expenditures proposed by SoCalGas and SDG&E on the grounds that there would be no after-the-fact reasonableness review of the expenditures, and because our proposal for an expedited advice letter process to review potential adjustments to approved PSEP funding levels would supposedly not provide interested parties with enough time to review the proposed changes.[14] In a similar vein, SCIP/Watson recommends that SoCalGas and SDG&E be required to obtain Commission authorization through a Tier 3 advice letter if the costs or scope of Phase 1A PSEP work increases beyond what the Commission has authorized, or if SoCalGas and SDG&E cannot complete the Phase 1A scope within the time or budget authorized.[15] TURN expresses similar concerns about SoCalGas' and SDG&E's proposed process for PSEP cost recovery,[16] and SCGC proposes that SoCalGas and SDG&E be required to file an

[12] *Id.*
[13] Motion filed on May 23, 2012.
[14] DRA Testimony (Sabino) at pp. 2-3.
[15] SCIP/Watson Testimony (Beach) at pp. 17-18.
[16] TURN Testimony (Long) at p. 7.

individual expedited application for each proposed pipeline replacement to ensure that pipelines are replaced only if truly necessary.[17]

None of the intervenor opposition to our PSEP-related cost recovery proposals has merit, and none of the competing suggestions from intervenors is reasonable or appropriate. SoCalGas and SDG&E believe their cost recovery proposal is a more efficient process for implementing their PSEP, given the limited resources of the Commission and the utilities. As long as costs incurred within the PSEP have been approved by the Commission, there should be no need for after-the-fact reasonableness review of the costs recorded in the PSEP Cost Recovery Accounts or for expedited applications for pipeline replacement projects. SoCalGas and SDG&E will review PSEP costs that are recorded in their PSEP Cost Recovery Accounts to ensure that these costs are truly incremental and not otherwise recovered in base transportation rates or subject to any other Commission-approved balancing account mechanism. SoCalGas and SDG&E also believe the proposed expedited advice letter requesting Commission approval for changes to the overall funding level adopted in this proceeding is appropriate and will provide sufficient time for review, especially when one takes into consideration that the Commission as well as other parties will be notified of this situation through SoCalGas and SDG&E's proposed annual status report. As indicated in direct testimony, the annual status report will provide the Commission and other parties information on any work completed during the previous year, work planned for the upcoming year, discussion of progress made to date and confirmation of the utilities Commission-approved annual Pipeline Safety Enhancement Plan budget.

[17] SCGC Testimony (Yap) at pp. 10-12.

SoCalGas and SDG&E believe that the proposal by SCGC for an individual expedited application for each proposed pipeline replacement is particularly unworkable and ill-advised. Our Pipeline Safety Enhancement Plan encompasses hundreds of potential pipeline replacements. Adding hundreds of new applications to the Commission's already burdened docket would severely strain the resources of the Commission and the utilities (not to mention intervenors), and would have a detrimental effect on all of the Commission's other work given the expedited nature of the new proceedings. Moreover, even if the new applications were expedited, the time required for each application (i.e., data/testimony presentation, hearings, briefs, proposed decision, comments, final decision) would undoubtedly delay our Phase 1 work well beyond the timeframes we have proposed. SCGC points to the Expedited Application Docket (EAD) procedure adopted by the Commission in the 1990s for discounted contracts to avoid bypass as a model for their new pipeline replacement expedited applications.[18] But the EAD docket dealt with dozens of proposed contracts, not hundreds of construction projects that are complex in scope. SCGC's proposal appears to be a thinly veiled procedural attempt to force SoCalGas and SDG&E into testing rather than replacing pipelines whenever possible. Our test/replace decisions should be made in accordance with the criteria and consultation process proposed by SoCalGas and SDG&E, as discussed by witness Rick Phillips. SoCalGas, SDG&E, and our customers should not be forced into pressure testing when it does not make sense just because it could take years to get a proposed replacement approved.

C. **PSEP Surcharge**

[18] SCGC Testimony (Yap) at p. 12.

SCGC recommends that PSEP costs should be transferred out of the PSEP cost recovery account and into base rates as quickly as feasible, and as soon as the projects are reflected in base rates they should be removed from the PSEP surcharge.[19] SoCalGas and SDG&E generally agree that the revenue requirements associated with PSEP projects should eventually be incorporated in the authorized revenue requirement in connection with a GRC. However, due to the magnitude of the PSEP and time period covered, SoCalGas and SDG&E believe that all PSEP costs should continue to be recovered through a surcharge rate, even after the costs are considered in our future GRCs. A permanent PSEP surcharge separately identified on customers' bills will provide transparency regarding the total cost of implementing PSEP. Base transportation rates will be reduced accordingly for PSEP costs that are addressed in connection with a GRC to ensure customers are not double charged for these costs. By implementing a permanent PSEP surcharge that includes the recovery of all PSEP costs, SoCalGas and SDG&E provide transparency to their customers that PSEP costs incurred on their behalf are consistent with the overall PSEP funding adopted in this proceeding, incorporated in rates in connection with a general rate case or other applicable proceeding, and/or modified in the future in connection with any request for changes in funding levels approved by the Commission.

D. Treatment of Robotics Royalties

Although no royalties have been received to date, SoCalGas has a small royalty interest stemming from RD&D investments in NYSEARCH's internal inspection robotics

[19] SCGC Testimony (Yap) at p. 29.

technology.[20] TURN recommends that 100% of royalties received be applied to offset PSEP costs.[21] SoCalGas and SDG&E disagree. These particular royalties should be handled in a consistent manner as with the Commission's treatment of other RD&D royalties associated with RD&D investments. As such, any royalties accruing to SoCalGas as a result of NYSEARCH's internal inspection robotics technology should be credited to the Research Development and Demonstration Expense Account (RDDEA),[22] thus reducing ratepayer costs dollar for dollar, until 100% of the project investment has been credited to customers. This treatment is consistent with reimbursing the cost of the investment to ratepayers in connection with SoCalGas' investment in Plug Power, Inc.[23] Thereafter, any additional royalties should be shared 60/40 between customers and shareholders, with the customers' allocation recorded in the Research Royalty Memorandum Account (RRMA), as provided for by the Commission in SoCalGas' most recent GRC.[24]

Just because a particular RD&D technology SoCalGas has supported has a potential application in the PSEP process does not mean that the treatment of related royalties should be changed to be less favorable to utility shareholders. As TURN admits, SoCalGas' RD&D efforts on this particular project is "an example of research, development and demonstration projects that have a strong potential to provide ratepayer benefits by lowering

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[20] SoCalGas/SDG&E Direct Testimony at page 56. NYSEARCH is the research arm of the Northeast Gas Association. The technology in question involves in-line inspection technology for formerly unpiggable pipelines.

[21] TURN Testimony (Marcus) at pp. 21-23.

[22] SoCalGas' Preliminary Statement, Part VI., Regulatory Accounts-Memorandum Accounts.

[23] Memorandum of Understanding as included in Attachment A of SoCalGas Advice No. 2865 which was approved by Commission letter on June 27, 2000. In this particular case, the reimbursement of the cost of the investment was recorded in the Pre-PBR Research Royalty Memorandum Account which provides no sharing with SoCalGas' shareholders.

[24] Pursuant to GRC D.08-07-046 and incorporated in SoCalGas' Preliminary Statement, Part VI., Regulatory Accounts-Memorandum Accounts. RRMA was established since SoCalGas Test Year 1994 GRC (D.93-12-043) with a sharing program established beginning in SoCalGas' 1997 Performance Based Regulation (D.97-07-054). SDG&E does not have a gas RD&D regulatory account mechanism.

operating costs."[25] SoCalGas and other utilities should be encouraged to enter into such projects, not discouraged by having the potential for sharing eliminated when and if a research project actually comes to fruition.

III. REVENUE REQUIREMENT ISSUES

A. AFUDC

TURN recommends that the Allowance for Funds Used During Construction (AFUDC) percentages should be 2% for small jobs and 5% for larger ones, as opposed to the SoCalGas and SDG&E authorized rates of return (ROR) of 8.68% and 8.40%, respectively.[26] TURN's proposed AFUDC rates are arbitrary, not consistent with historical AFUDC methodology, and do not follow the FERC guidelines.

SoCalGas and SDG&E's AFUDC rates are appropriate and adhere to FERC guidance for computing AFUDC. The AFUDC mechanism is designed to compensate SoCalGas and SDG&E investors for the delayed recovery of their investment due to long construction periods. As a result, SoCalGas and SDG&E use their respective authorized capital structure and authorized ROR as a reasonable proxy for AFUDC. SoCalGas and SDG&E's use of ROR for AFUDC in our PSEP proposal is consistent with the methodology used in calculating the capital forecast and associated revenue requirement approved in the past GRCs and recently filed incremental projects such as SoCalGas and SDG&E's AMI applications. In addition, SoCalGas and SDG&E's use of the authorized ROR for AFUDC approximates actual AFUDC, which is derived in accordance with the formula prescribed in the FERC Code of Federal Regulations (CFR), Subchapter F, Part 201, Section 3.17.

B. Appropriate Treatment of Non Destructive Examination Costs

[25] TURN Testimony (Marcus) at p. 22.
[26] TURN Testimony (Marcus) at p. 8.

SCGC recommends that the Commission adopt SoCalGas' and SDG&E's proposal to use non destructive examination (NDE) instead of pressure testing or replacement for pipeline segments that are 1,000 feet or less in length.[27] Ms. Yap further recommends, however, that all NDE costs (including pipe coating and repair activities) should be entirely expensed.[28]

SoCalGas and SDG&E disagree with SCGC's proposal that all NDE costs be expensed. If the NDE alternative is approved by the Commission, SoCalGas and SDG&E should be allowed to treat NDE costs consistent with our standard treatment of these types of activities. That is, SoCalGas and SDG&E would capitalize or expense the NDE costs according to our existing capitalization policy that has been used in presenting the capital and O&M forecast and associated revenue requirement approved in the past general rate cases. There is no reason to change this standard treatment for PSEP-related NDE costs.

C. Appropriate Treatment of Project Loaders

1. Incremental Overhead Loaders

DRA asserts that SoCalGas and SDG&E need to prove that the PSEP overheads are truly incremental[29]; SoCalGas and SDG&E have met this burden.

As explained in direct testimony, overhead costs are costs that indirectly support the business operations of the utilities.[30] SoCalGas and SDG&E allocate these indirect costs to particular projects through the use of overhead loading rates. SoCalGas' and SDG&E's accounting systems apply over 20 different classes of overhead rates to various

[27] SCGC Testimony (Yap) at pp. 14-15. As explained in our direct testimony NDE uses a variety of inspection methods – radiography, ultrasonic inspection, and magnetic particle inspection – to determine if a pipeline is sound. NDE techniques are manual methods that are economical only for shorter lengths of pipeline. *See* SoCalGas and SDG&E direct testimony at 56-57.
[28] SCGC Testimony at p. 16.
[29] DRA Testimony (Sabino) at p. 24.
[30] Amended PSEP testimony of Cheryl Shepherd (Chapter X), at p. 122.

combinations of company labor, contract labor, purchased services, and materials. However, many of these costs are already fully recovered in base utility rates and therefore not applicable to our PSEP proposal, which is prepared on an incremental basis. Only eight overhead loaders have been identified as being applicable to PSEP-related expenditures – (1) payroll tax; (2) vacation and sick time; (3) benefits (non-balanced only), (4) workers' compensation, (5) public liability / property damage, (6) incentive compensation plan, (7) purchased services and materials, and (8) administrative and general. Each of these loaders is incremental because they will proportionately increase as a result of our proposed PSEP work (consider the case where new employees will need to be employed to support the PSEP day-to-day work such as processing invoices). Overhead loaders and their application method presented in the PSEP testimony[31] are appropriate and are consistent with how they were applied in calculating the capital and O&M costs in other approved incremental projects, such as SoCalGas' AMI[32] and SDG&E's AMI.[33]

2. Incentive Compensation Plan Loader

TURN recommends that the Commission reject SoCalGas' and SDG&E's proposal to apply an Incentive Compensation Plan (ICP) overhead loader to its PSEP-related O&M and capital costs.[34] SoCalGas and SDG&E respectfully disagree with this recommendation.

ICP is a component of SoCalGas' and SDG&E's total compensation program. As implementing the PSEP will require additional employees to complete the necessary work, it is appropriate to reflect the total compensation, including ICP loaders, in the PSEP-related

[31] Amended PSEP testimony of Cheryl Shepherd (Chapter X).
[32] Testimony of Michael Foster (Chapter VII) in SoCalGas Application (A) 08-09-023; Settlement adopted in Decision (D) 10-04-027.
[33] Testimony of Scott Kyle (Chapter 13 SK-2) in SDG&E Application (A) 05-03-015; Settlement adopted in Decision (D) 07-04-043.
[34] TURN Testimony (Marcus) at pp. 8-9.

O&M and capital costs. Employees are critical to providing safe, efficient, and reliable service to our customers. With the aggressive schedule of PSEP, it is important to attract and retain well qualified employees at both utilities and the incentives provided by ICP are an important element of that process. Therefore, it is both reasonable and appropriate to include this ICP component of employee compensation in PSEP.

SoCalGas and SDG&E also strongly dispute TURN's claims that it would not be in the best interest of ratepayers to include an ICP loader in the PSEP. As the Commission has previously determined on a number of occasions, reasonable incentive compensation programs are indeed in the best interest of customers. For example, in SoCalGas' 2008 GRC decision, the Commission recognized the benefits of ICP to our customers, and determined that customers should fund an ICP-related revenue requirement:

> Because total compensation is reasonable, (defined as prevailing market rates for comparable skills) the ratepayers should reasonably fund a revenue requirement that includes the full market-based employee compensation for the adopted levels of staff. Thus, there is no basis to exclude the incentive component and force shareholders to assume a portion of the reasonable cost of employee compensation. We find no merit in DRA's argument that shareholders should fund any portion of the incentive portion of market-based employee compensation. We do not agree that incentives solely benefit the company: if employees work harder or smarter to earn incentives (even just to achieve the target incentives) then ratepayers should benefit too. We do not agree that incentives solely benefit the company: if employees work harder or smarter to earn incentives (even just to achieve the target incentives) then ratepayers should benefit too.[35]

Consistent with current utility practices and past guidance from the Commission, ICP loaders should be included in the PSEP.

This concludes my prepared rebuttal testimony.

[35]D.08-07-046, mimeo., at 22.

CHAPTER 15

WITNESS QUALIFICATIONS

PREPARED REBUTTAL TESTIMONY

OF W. DAVID MONTGOMERY

I. QUALIFICATIONS

My name is W. David Montgomery, and I am Senior Vice President of NERA Economic Consulting, 1255 23rd Street NW, Washington, DC 20035. My relevant experience includes teaching, government service, research and consulting dealing with natural gas and regulation of energy markets. I have a Ph.D. in economics from Harvard University and taught economics at Caltech and Stanford. My publications include papers on utility regulation and on natural gas markets and regulation in the American Economic Review and in other peer-reviewed journals and edited volumes. I have testified before the U.S. Congress on numerous occasions on topics dealing with energy regulation and energy and environmental policies. I appeared before this Commission in its investigation of natural gas price increases in California in 2000 and 2001 and have been an expert witness in antitrust litigation, international arbitration, and price manipulation investigations involving natural gas markets. My qualifications are addressed in more detail in my resume which is attached hereto.

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W. DAVID MONTGOMERY
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W. David Montgomery is an expert on the economic issues associated with climate change policy, and testifies as an expert witness in state and federal courts on antitrust and damages cases dealing with petroleum and natural gas markets. His scholarly work is frequently published in peer-reviewed journals, and Congressional committees have requested his testimony on climate change, issues affecting oil and gas markets, and other energy market and environmental issues on numerous occasions. He advises clients on the strategic implications of changes in energy and environmental policies and energy markets. He has served as a lead economic witness in high profile litigation, including cases dealing with liability for MTBE spills, the applicability of the public trust doctrine to U.S. climate policy, an injunction against the enforcement of California's low carbon fuel standard, and in the Continental Forge antitrust litigation alleging a conspiracy to raise natural gas prices in California.

Dr. Montgomery's work on economic issues associated with climate change policy has been published frequently in peer-reviewed journals. He was a principal lead author of the Second Assessment Report of the Intergovernmental Panel on Climate Change (IPCC), Working Group III, and the author of a number of studies of climate change policy over the past 20 years. His testimony on climate change issues has been requested on numerous occasions by the U.S. Congress. While at Charles River Associates, Dr. Montgomery directed the development of a set of integrated economic models that set the standard for analysis of the international, national, and industry impacts of proposed emission limits, including the MRN and MRN-NEEM models. He and his colleagues have played a leading role in IPCC studies and expert workshops assessing economic impacts on developing countries.

Dr. Montgomery's current research deals with the design of R&D policy and the relationship between institutional change and the reduction of greenhouse gas emissions in developing countries. He has led a number of strategic assessments for clients in the private sector, advising them on how future climate policies and other environmental regulations could affect their asset value, investment decisions, and strategic direction. His recent work includes studies of California's policies to limit greenhouse emissions and energy and climate legislation in the U.S. Congress.

Dr. Montgomery has testified as an expert witness in litigation involving energy markets, including a number of utility mergers, antitrust and price manipulation cases, international arbitration, and environmental damages. His recent work includes studies on potential effects of gasoline price-gouging legislation, the effects of windfall profits taxes and other proposed tax changes on oil and gas markets, the impacts of cap and trade legislation on energy markets, and the design of low carbon fuel standards. His testimony on issues affecting oil and gas markets, as well as other energy market and environmental issues, has been requested on numerous occasions by committees of the U.S. Congress.

Prior to entering consulting, Dr. Montgomery held a number of senior positions in the United States Government. He was assistant director of the U.S. Congressional Budget Office and deputy assistant secretary for policy in the U.S. Department of Energy, and he headed the energy modeling and forecasting activities at the Energy Information Administration. He taught economics at the California Institute of Technology and Stanford University, and he was a senior fellow at Resources for the Future. Dr. Montgomery holds a Ph.D. in economics from Harvard University and was a Fulbright Scholar at Cambridge University. He received the Association of Environmental and Resource Economists' 2005 award for a "Publication of Enduring Quality" for his pioneering work on emission trading.

Education

Harvard University
PhD, Economics

Cambridge University
Fulbright Scholar

Wesleyan University
B.A. Social Studies

Professional Experience

NERA Economic Consulting
Senior Vice President

Charles River Associates
Vice President, Head of Energy and Environment Practice

Stanford University
Visiting Lecturer

DRI/McGraw-Hill
Group Director

Congressional Budget Office

Assistant Director for Natural Resources and Commerce

Office of the Secretary of Defense
Director, Office of Economic Analysis

US Energy Information Administration
Director, Office of Energy Markets and End Use

Resources for the Future
Senior Fellow

US Department of Energy
Deputy Assistant Secretary for Systems Analysis, Office of Policy and Evaluation

California Institute of Technology
Assistant Professor of Economics

Professional Activities and Awards

Recipient of 2004 "Publication of Enduring Quality Award" from the Association of Environmental and Resource Economists.

Member, Federal Advisory Committee for the Energy Information Administration, 2000-2002
Visiting Lecturer, Department of Management Science and Engineering, Stanford University, 1993 and 2000.

Study Director, Energy Modeling Forum Study of World Oil Supply and Demand, 1989–1990.
Member, Board of Editors, *The Energy Journal*, 1980-82.

Major Publications

"An Interpretation of Walras' Theory of Capital as a Model of Economic Growth." *History of Political Economy* 3, No. 2, Fall 1971.

"Markets in Licenses and Efficient Pollution Control Programs." *Journal of Economic Theory* Vol. 5, No. 6, December 1972.

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Expert witness before the U.S. International Trade Commission on outlook for oil and gas drilling activity in proceeding dealing with Oil Country Tubular Goods Industry, 2001.

Invited Testimony, Hearing on The Long Term Outlook for Energy Markets, Subcommittee on Energy, Committee on Science, U.S. House of Representatives, Washington, DC, May 3, 2001.

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Invited Testimony, Hearing on Climate Science and Economic Impacts of Climate Policy, Committee on Energy and Natural Resources, United States Senate, July 21, 2005.

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Expert Reports on behalf of Duke Energy LNG Sales, Inc, filed in Arbitration Pursuant To The Uncitral Arbitration Rules, Sonatrach & Sonatrading Amsterdam B.V., Claimants, v. Duke Energy LNG Sales, Inc, Respondent, April 22, 2005 and November 11, 2005. Oral testimony February 2006.

Consulting expert for defendants in an antitrust and damages case dealing with natural gas price reporting in California.

Expert witness for defendant in FERC investigation of manipulation of natural gas prices.

Expert witness in arbitration dealing with breach of a delivery contract for biodiesel.

Invited testimony, Hearing on The Role of Science in the Asia-Pacific Partnership, Committee on Commerce, Science and Transportation Subcommittee on Global Climate Change and Impacts, United States Senate, Washington, DC, April 4, 2006.

Invited Testimony, Hearing on Energy and Tax Policy, Committee on Ways and Means, U.S. House of Representatives, February 28, 2007.

Invited Testimony, Hearing on U.S. Re-Engagement to the Global Effort to Fight Climate Change, Committee on Foreign Affairs, U.S. House of Representatives, May 15, 2007.

Invited Testimony, Hearing on Price-Gouging Legislation, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, U.S. House of Representatives, May 22, 2007.

Invited Testimony, Hearing on Allowance Allocation Policies in Climate Legislation, Subcommittee on Energy and Environment, Committee on Energy and Commerce, U.S. House of Representatives, June 9, 2009.

Expert witness on market share liability on behalf of ExxonMobil, with expert reports and testimony before a Federal jury in September 2009. Southern District Of New York, in Re: Methyl Tertiary Butyl Ether MDL No. 1358 (“MTBE”) Products Liability Litigation Master File No. 1:00-1898(SAS) Case No. 04-CV-3417(SAS) City of New York (Plaintiff) Amerada Hess Corp., et al. (Defendants).

Expert witness on climate policy and natural gas and carbon price scenarios before the Mississippi Public Utilities Commission Docket No. 2009-UA-0014, on behalf of Mississippi Power, testimony submitted December 2009 with hearing in February 2010.

Expert witness on R&D practices in oil and gas exploration on behalf of ExxonMobil and Murphy Oil, September 2009. In the arbitration under Chapter Eleven of the NAFTA and the ICSID Arbitration (Additional Facility) Rules between: Mobil Investments Canada Inc. & Murphy Oil Corporation Claimants and Government of Canada Respondent ICSID Case No. ARB(AF)/07/.

Expert witness on natural gas prices and contracts on behalf of Peabody Energy Corporation. Before the Colorado Public Service Commission, Hearing on Implementation of the Clean Air Clean Jobs Act, December 2010.

Invited Testimony, U.S. Senate Committee on Environment and Public Works, Subcommittee on Green Jobs and the New Economy, Hearing on Green Jobs and Trade, February 15, 2011.

Invited Testimony, U.S. House of Representatives, Committee on Energy and Commerce, Subcommittee on Energy and Power, Hearing on EPA's Greenhouse Gas Regulations and Their Effect on American Jobs, March 1, 2011.

Invited Testimony, U.S. Senate Committee on Environment and Public Works, Subcommittees on Air Pollution and Nuclear Power and on Green Jobs and the New Economy, Hearing on Clean Air Act Regulations and the Economy, March 17, 2011.

Invited Testimony, U.S. House of Representatives Committee on Science, Space, and Technology Subcommittee on Investigations and Oversight Green Jobs and Red Tape: Assessing Federal Efforts to Encourage Employment April 13, 2011

Invited Testimony, U.S. House of Representatives Subcommittee on Regulatory Affairs, Stimulus Oversight, and Government Spending The Green Energy Debacle: Where Has All the Taxpayer Money Gone? November 2, 2011

Expert witness in regard to liability for MTBE spills in New Hampshire on behalf of ExxonMobil. State Of New Hampshire Superior Court Docket No: 03-C-550 State Of New Hampshire V. Hess Corporation, Et Al.

Expert declarations on the impacts of California’s Low Carbon Fuel Standard (LCFS) on behalf of the American Fuel and Petrochemicals Association, intervenors in the appeal of an injunction staying enforcement of the California LCFS. United States Court Of Appeals for the Ninth Circuit, Rocky Mountain Farmers Union, et al. Plaintiffs-Appellees, v. James Goldstene, in His Official Capacity as Executive Officer of the California Air Resources Board, et al. Defendants-Appellants, on Appeal from the United States District Court for the Eastern District of California in Case Nos. 09-CV-02234 & 10-CV-00163

Expert declaration on the economic impacts of climate policy on behalf of the National Association of Manufacturers and National Petroleum Refiners Association, intervenors in opposition to an argument under the Public Trust Doctrine that the United States Government should be compelled to regulate greenhouse gas emissions. United States District Court Northern District of California, Alec L., et al., Plaintiffs, vs. Lisa P. Jackson, et al., Defendants. Case No. C11-02203 EMC

PREPARED REBUTTAL TESTIMONY

OF LEE STEWART

I. QUALIFICATIONS

My name is Lee Stewart. I was employed by Southern California Gas Company (SoCalGas) from 1967 to 2010. I was the Senior Vice President of Operations at SoCalGas from 2006 until my retirement in 2010. Following the creation of the Sempra Energy Utilities group in 1998, I was also responsible for the SDG&E transmission system.

I earned a Bachelor of Science degree in Engineering from the University of California, Los Angeles. I am a Registered Engineer in California and have held several industry leadership roles, including Chairman of the Operation Section of the American Gas Association (AGA), Chairman of the Pipeline Research Council International, and Board of Director of the Gas Research Institute and its successor, Gas Technology Institute.

Throughout my 43 year career at SoCalGas, I held numerous positions in the Operations side of the business, primarily in Distribution, Transmission and Engineering. I was first employed by Southern Counties Gas in 1967 (Southern Counties Gas merged with SoCalGas in 1970). My career in the Transmission arena began in the 1970's working on the design of the Honor Rancho storage field, followed by being the design manager for the Ten Section Storage Project. In the 1980's, I was responsible for a transmission operation region and for the pipeline system design as Manager of Engineering. I was appointed to Vice President of Transmission in 1990. From 1990 until my retirement in 2010, I was responsible for the design, construction, operation and maintenance of the transmission system as its direct officer, or through a direct subordinate officer. Various positions throughout this period include: President of Energy Transportation Services (1995), Senior Vice President of Transmission (2000), and Senior Vice

President of Operations (2006). I was Senior Vice President of Operations until my retirement in 2010.

I have previously testified before the Commission.

EXPERT TESTIMONY

OF MICHAEL J. ROSENFELD

I. QUALIFICATIONS

I am qualified to submit this testimony by training, and experience as a mechanical engineer since 1979. I have been employed since 1991 by Kiefner & Associates, Inc. (KAI) in Worthington, Ohio, a consulting firm that provides technical services to oil and gas pipeline operators and pipeline industry groups, including pipeline failure investigations, fitness for service assessment, integrity assessment procedures, engineering analysis, risk assessment, codes compliance, research, training, and other services. My current position is Vice President and General Manager following acquisition of KAI by Applus-RTD, an international certification and inspection company. Prior to that, I was President of KAI for 10 years.

During my employment with KAI, I have provided consultation to numerous oil and gas pipeline operators in technical matters related to pipeline fitness for service, integrity assessment, remaining life estimation, design, repairs, failure investigations, risk, materials selection, fracture control, welding, and compliance to standards and regulations, among others. I have also conducted several research projects on matters related to pipeline integrity for various pipeline industry research groups, including the Pipeline Research Council International (PRCI), the Gas Technology Institute (GTI), and the American Society of Mechanical Engineers (ASME). I am a member of the ASME B31.8 Section Committee since 1994, and was Vice Chair of the committee for 4 years. I am also a member of the ASME B31 Mechanical Design Committee since 1990, a member of the ASME B31 Standards Committee since approximately 1999, and the ASME Board of Pressure Technology Codes and Standards since 2008. I am also the instructor for ASME Continuing Education’s Professional Development course on the ASME B31.8 standard, and was awarded ASME Fellow in 2012.

Prior to joining KAI, I was employed for 6 years by Battelle Memorial Institute, Columbus, Ohio, a research and development organization. During that time I performed engineering analysis in a broad range of industrial and defense projects, including research on pipeline integrity matters for natural gas pipeline operators and for PRCI. Prior to joining Battelle, I was employed for 4 years at Impel Corporation in Melville, NY performing stress analyses of nuclear power plant piping systems, equipment, and structures for seismic and other conditions.

I am a registered Professional Engineer in the State of Ohio.

EXPERT TESTIMONY

OF HARVEY H. HAINES

I. QUALIFICATIONS

I am qualified to submit this testimony by training and experience in measurements since 1982. I have been employed starting in 2002 by Kiefner and Associates, Inc. (KAI) a Worthington, Ohio consulting firm that provides technical services to oil and gas pipeline operators and pipeline industry groups, including pipeline failure investigations, fitness for service assessment, integrity assessment procedures including in-line inspection assessments, risk assessment, codes compliance, research, training , and other services. My current position is Senior Pipeline Specialist.

During my employment with KAI I have provided consultation to numerous oil and gas pipeline operators in technical matters related to in-line inspection measurements, operational reliability assessment, and training. I co-teach a KAI workshop on Pipeline Reliability Assessment several times per year, where the various causes of pipeline failure are presented including a discussion of pipeline defects and pipe properties. We spend the significant portion of the workshop discussing the advantages and disadvantages of assessing pipeline threats using ILI, hydrotesting, and direct assessment.

Prior to joining KAI, I was employed by the Gas Research Institute (GRI) for 11 years, including 7 years as the program manager responsible for development of ILI inspection technologies for the U.S. Gas industry. I was responsible for a $5 million annual budget dedicated to understanding and improving ILI technology for detection and sizing of all defects in pipeline steels. Projects included efforts to better understand the sizing capability of magnetic flux leakage (MFL) technology, including efforts to understand circumferential MFL (CMFL).

Another major effort was to develop electromagnetic acoustic transducer (EMAT) technology to detect and size cracks in the pipe body and adjacent to the long seam. In the 4 years at GRI prior to joining the transmission pipeline group, I was responsible for cased-hole logging R&D in the exploration and production group.

Prior to joining GRI in 1990, I spent 8½ years with Chevron as a petrophysicist evaluating rocks using non-destructive geophysical measurement techniques. These geophysical measurement techniques are very similar to the techniques used for NDE of pipeline steels.

My academic training is as a geophysicist with B.S. 1980 and M.S. 1982 degrees from the Massachusetts Institute of Technology.

I am a current member of NACE International, the SPWLA, and a committee member of the PRCI Operations and Inspection Technical Committee.

PREPARED REBUTTAL TESTIMONY

OF RICHARD PHILLIPS

I. QUALIFICATIONS

My name is Richard D. Phillips. I have been employed by Southern California Gas Company since 1978. I have held various positions in the Distribution, Transmission, Storage, Engineering, IT and Customer Service functional areas. Additionally, I have been in the electric and gas distribution functional organization at SDG&E, as well as in the supply management and IT functional areas for both SoCalGas and SDG&E.

My current position is Director, Pipeline System Enhancement Program – Project Management Office.

I earned a Bachelor of Science degree in Engineering from the University of California, Irvine, cum laude. I am a registered professional engineer in California. I am a past member of the Pipeline Research Council International.

I have previously testified before the Commission.

PREPARED REBUTTAL TESTIMONY

OF JOHN L. DAGG

I. QUALIFICATIONS

I, John L. Dagg, am Director of Gas Transmission and System Operations for SoCalGas and SDG&E. I hold a BS degree in Mechanical Engineering from California State University, Northridge. I have a broad background in engineering and natural gas pipeline operations with over 30 years of experience with SoCalGas. I have held a number of technical and managerial positions with increasing responsibility in the Gas Engineering, Gas Operations, Gas Distribution, and Gas Transmission Departments. In these positions, I was responsible for gas system control operations, field operations, technical services, and engineering design and construction. I have held my current position as the Director of Gas Transmission and System Operations since April 2009. I have testified previously before the Commission.

PREPARED REBUTTAL TESTIMONY

OF STEVE WATSON

I. QUALIFICATIONS

My name is Steve Watson. I am employed by Southern California Gas Company (SoCalGas) as the Capacity Products Staff Manager. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I received a Bachelor's degree in History and International Relations from the University of California, Davis, and a Master's Degree in Public Policy from the University of California, Berkeley. I have been employed by SoCalGas since 1986. I have worked in Gas Supply, Customer Services, the Strategic Planning and Transmission Capacity Planning Departments. I am currently the Capacity Products Staff Manager, responsible for staff support to our Pipeline Products Manager and Storage Products Manager. Before joining SoCalGas I worked as a natural gas analyst at the Department of Energy.

I have previously testified before this Commission.

PREPARED REBUTTAL TESTIMONY

OF EDWARD J. REYES

I. QUALIFICATIONS

My name is Edward J. Reyes. My business address is 555 West Fifth Street, Los Angeles, California 90013. I am employed by Southern California Gas Company ("SoCalGas") as the Director of Finance. In my current position my responsibilities include overseeing the strategic and financial analysis in support of new investment opportunities, the development and analysis of ratebase, and implementation of revenue requirements, regulatory accounts, and cost recovery strategies for SoCalGas. I have been in this position since June 2012.

I received a Bachelor of Science from California State University, Dominguez Hills in May 1994. I was initially employed by SoCalGas in November 1994 and have held various positions of increasing responsibility in the Accounting and Finance areas of the company, including Cost Accounting, Financial Accounting, Accounts Payable, New Business Accounting, Financial Systems, Affiliate Billing & Costing and Financial & Strategic Analysis.

I have previously testified before the California Public Utilities Commission.