BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms.	)))))))	R.11-02-019 (Filed February 24, 2011)

OPENING COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 M) ON PROPOSED DECISION MANDATING PIPELINE SAFETY IMPLEMENTATION PLAN, DISALLOWING COSTS, IMPOSING EARNINGS LIMITATIONS, ALLOCATING RISK OF INEFFICIENT CONSTRUCTION MANAGEMENT TO SHAREHOLDERS, AND REQUIRING ON-GOING IMPROVEMENT IN SAFETY ENGINEERING

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TABLE OF CONTENTS

SB_GT&S_0549433

TABLE OF AUTHORITIES

Page

Federal Decisions

Federal Regulations

California Agency Decisions

California Statutes

CPUC Rules and Regulations

Miscellaneous

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Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) submit the following Opening Comments on the Proposed Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Imposing Earnings Limitations, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring On-Going Improvement in Safety Engineering (Proposed Decision) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission (the Commission).

I. INTRODUCTION AND PROCEDURAL HISTORY

On February 24, 2011, the Commission adopted Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms (OIR) instituting this Rulemaking. In the OIR, the Commission described this Rulemaking as "a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all

California pipelines. Specific investigations of PG&E's conduct and any penalties will take place in a separate docket."[1]

The Commission declared on June 9, 2011, that "all natural gas transmission pipelines in service in California must be brought into compliance with modern standards of safety. Historic exemptions must come to an end with an orderly and cost-conscience implementation plan."[2] To accomplish this mandate, the Commission directed all California natural gas pipeline operators to 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 has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)."[3]

As directed, on August 26, 2011, Pacific Gas and Electric Company (PG&E), SoCalGas, SDG&E and Southwest Gas Corporation filed proposed plans to meet the Commission's objectives. The Commission initially contemplated considering all of the proposed plans simultaneously in this Rulemaking, but later determined it should consider PG&E's proposed plan first and transfer consideration of SoCalGas and SDG&E's proposed plan to their Triennial Cost Allocation Application Proceeding (TCAP) (A.11-11-002).[4] Intervenor testimony on SoCalGas and SDG&E's plan was submitted after briefing occurred on PG&E's plan, and hearings on SoCalGas and SDG&E's plan did not take place until late August.

Because our plan is being reviewed after PG&E's, SoCalGas and SDG&E urged the Commission in this proceeding to refrain from determining material issues that may apply to our plan until we have had an opportunity to fully present our case and submit evidence supporting our plan.[5] In particular, SoCalGas and SDG&E asked the Commission to refrain from adopting

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1 OIR at 3.
2 D.11-06-017 at 18.
3 D.11-06-017 at 31, Ordering ¶ 3.
4 *See* D.12-04-021.
5 Opening Brief of SoCalGas and SDG&E on PG&E's Implementation Plan at 9.

parties' ratemaking proposals that were based on historic recordkeeping and pressure testing practices:

> Should DRA and TURN set forth similar proposals with respect to SoCalGas and SDG&E's plan, SoCalGas and SDG&E intend to offer evidence regarding historic natural gas industry pressure testing and recordkeeping practices and standards in support of their proposed plan. SoCalGas and SDG&E will effectively be deprived of a full and fair opportunity to present their case, if the Commission renders factual determinations regarding historic recordkeeping and pressure testing standards and practices in the industry solely based on the record created during the review of PG&E's Implementation Plan.[6]

As SoCalGas and SDG&E anticipated, DRA and TURN made virtually identical proposals for "shareholder responsibility" and "disallowances" with respect to our plan as they proposed for PG&E. These issues were hotly contested in testimony and at hearings, and SoCalGas and SDG&E presented new evidence, not presented in this proceeding, that demonstrate the fallacy of DRA and TURN's positions. The briefing on SoCalGas and SDG&E's plan has just finished, and TURN, in particular, has relied on the Proposed Decision in its briefs.

In the comments that follow, SoCalGas and SDG&E explain why the Proposed Decision, which denies cost recovery for pressure testing pipelines installed after 1956, is in error and would be prejudicial to SoCalGas and SDG&E, if adopted without taking into consideration the additional evidence presented in connection with SoCalGas and SDG&E's plan.

In addition, SoCalGas and SDG&E comment on the Proposed Decision's determinations to adjust PG&E's return on equity, to disallow all contingency costs, and to adopt an unrealistic escalation rate. These elements of the Proposed Decision appear to be intended to redress past conduct by PG&E. It is a mistake to use these mechanisms as a form of punishment.

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6 *Id.* at 11.

II. DISCUSSION

A. The Commission Should Consider the Evidence Presented by SoCalGas and SDG&E on Cost Responsibility Issues in the TCAP Before Making Final Cost Responsibility Determinations.

It appears to SoCalGas and SDG&E that there is no specific intent in the Proposed Decision to apply any PG&E-related findings and conclusions directly to SoCalGas and SDG&E. That said, it is hard to imagine that at least some elements of the Proposed Decision, as currently drafted – such as the rationale for shareholder responsibility with respect to 1956-1961 vintage pipelines that lack a record of a pressure test – will not be used by the parties to argue general applicability to the State's other natural gas utilities.

As explained above, the Commission is currently considering SoCalGas and SDG&E's proposed pipeline safety plan in the TCAP. The Commission made a conscious decision to consider SoCalGas and SDG&E's proposed pipeline safety plan separately from and after PG&E's. This treatment allows the Commission the ability to analyze the plans of each utility on their own separate merits, and to respond to utility-specific factual issues in an appropriate manner. The decision to separate the plans will be a blueprint for unfair treatment, however, if the findings and conclusions that the Commission makes with respect to PG&E's proposed plan, and the requirements and rate treatment that the Commission establishes for PG&E, are treated as precedent for SoCalGas and SDG&E.

SoCalGas and SDG&E presented evidence in the TCAP demonstrating that the recommendations by DRA, TURN, and certain other interested parties for pipeline safety plan "shareholder responsibility" and "disallowances" are unsupported and would create perverse incentives and ultimately increase customer costs. Our positions are supported by voluminous, specific, and uncontroverted testimony from utility witnesses and recognized industry experts, including George Tenley, Jr.,[7] Michael Rosenfeld,[8] and Dr. David Montgomery.[9]

In a few instances in these comments, SoCalGas and SDG&E reference some of that evidence. While the Commission may take notice in this proceeding of record evidence relating to the same topics presented in a contemporaneous Commission proceeding,[10] our comments present only a tiny fraction of the relevant arguments and evidence from Phase 1 of our TCAP. This evidence should be considered by the Commission before it renders determinations in this proceeding that could effectively pre-determine issues currently before the Commission in the TCAP. Indeed, it would be unfair (and could violate SoCalGas and SDG&E's due process rights) not to do so.

To avoid this unfair result, SoCalGas and SDG&E respectfully request that the Commission refrain from pre-determining issues in this proceeding that are also before the Commission in our TCAP. These issues all relate to intervenors' "shareholder responsibility" and "disallowance" proposals, as well as related determinations regarding the existence of pressure testing and recordkeeping requirements for pre-1970 vintage pipelines, the effect of missing records, and the policy determination of whether the Commission should allow the "grandfathering" of pre-1970 pipelines that have not been pressure tested to modern Subpart J standards. Because these issues relate to who should pay to implement PG&E's proposed plan, rather than whether PG&E's plan should move forward, the Commission can and should issue a determination with respect to these mutual issues only after it has had an opportunity to consider all of the record evidence from the TCAP.

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7 Mr. Tenley has over 20 years of experience as a federal regulator and is former Chief Counsel and head of the Pipeline Safety Office in the Department of Transportation's Research and Special Programs Administration (RSPA), the predecessor to the Pipeline and Hazardous Materials Safety Administration (PHMSA).

8 Mr. Rosenfeld is a mechanical engineer and consultant with extensive experience dealing with the pipeline safety standards and regulations simultaneously at issue in both this proceeding and Phase 1 of our TCAP.

9 Dr. Montgomery is a well-recognized economic expert specializing in utility regulatory issues who has held a number of senior positions in the United States Government (*e.g.*, Deputy Assistant Secretary at the United States Department of Energy) as well as teaching positions at Stanford and Caltech.

10 *See* Rule 13.9, Commission's Rules of Practice and Procedures; Cal. Evid. Code § 452.

If the Commission decides it cannot delay its determination of the issue of who should pay for implementation of PG&E's plan, the Commission should at a minimum explicitly state in its decision regarding PG&E's plan that the findings and conclusions in the decision apply to PG&E alone, are not intended to be precedential for the State's other natural gas utilities, and will not be used by the Commission in evaluating the pipeline safety plans of the State's other natural gas utilities.

B. The Proposed Decision Errs by Exempting Older Natural Gas Transmission Pipelines from the Commission's New Pressure Testing Requirements.

The Proposed Decision excludes the costs of pressure testing pipelines installed between 1956 and 1961 where pressure test records are missing because "PG&E undertook or stated that it undertook to comply with industry standards but no longer possesses the records of such compliance."[11] According to the Proposed Decision, "[t]he evidentiary record supports the factual finding that from 1956 on, PG&E's practice was to comply with then-applicable industry standards for pre-service pressure testing, and that retaining records of such testing was part of the industry standard. As it was PG&E's practice to incur these pre-service test costs, we would expect that absent unusual circumstances such costs would be included in revenue requirement and recovered from ratepayers."[12]

The corollary to this conclusion is necessarily that where PG&E has a pressure test record from the 1950s, it does not have to pressure test that pipeline under its plan. But this is contrary to the Proposed Decision's Conclusion of Law Paragraph 19 and the Commission's express direction in D.11-06-017. As noted by the Commission in D.11-06-017, California natural gas transmission pipelines installed prior to July 1, 1970, were exempted from Federal pipeline safety regulations that require new transmission pipelines to be pressure tested prior to being

11 Proposed Decision at 60.
12 *Id.* at 61.

placed in service.[13] The Commission expressed concern about these exemptions in D.11-06-017, stating:

> Consequently, the untested pipelines are also some of the oldest in the natural gas transmission system and the more likely to lack a complete set of documents allowing pipeline feature documents to be established without the use of assumptions. We find that this circumstance is not consistent with this Commission's obligations to promote the safety, health, comfort, and convenience of utility patrons, employees, and the public. [14]

That is why the Commission ordered that *all* transmission pipelines must now be tested to modern standards, and that "[h]istoric exemptions must come to an end . . ."[15] The Commission expressly and unambiguously eliminated grandfathering with its bold move to modern testing standards in D.11-06-017. It is legal error for the Proposed Decision to reinstitute "grandfathering," by now concluding that pressure testing from the 1950s would be sufficient to satisfy the requirements of D.11-06-017.

Pressure test standards have changed over time: the pressure testing requirements in the 1950s do not meet modern standards (also referred to as Subpart J standards, which are codified at 49 CFR 192). No party in PG&E's hearing disputed this point and SoCalGas and SDG&E provided additional evidence in their proceeding that demonstrates the differences between pre-1970 pressure testing requirements and modern standards. For example, SoCalGas and SDG&E introduced the following table, which summarizes the strength testing and associated record keeping requirements of industry standards and regulatory requirements:

13 D.11-06-017 at 5, n. 3.
14 *Id*. at 18.
15 *Id*. at 31, Ordering ¶ 4.

Summary Table of Post Construction Pressure Tests and Duration[16]

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.

16 A.11-11-002, Ex. SCG-18 (Schneider) at 9 (Figure DMS-2).

The Proposed Decision orders "similar treatment for pipeline installed after 1961, lacking pressure test records . . . ."[17] Like the voluntary industry standards that existed between 1956 and 1961, General Order 112, first adopted in 1961, did not require newly-installed transmission pipelines to be pressure tested according to the modern standards that were subsequently adopted by Federal regulators ten years later. Again, this fact is not in dispute in either proceeding. Thus, even if a pipeline operator retained complete pressure test records for pipelines installed between 1961 and 1970, those pipelines would still need to be either retested or replaced in order to bring those pipelines into compliance with modern pressure testing standards.

The implication of exempting pipelines installed prior to 1970 from the Commission's new modern pressure testing standards is that the pipelines the Commission expressed most concern about may still be grandfathered, just under a newly-created Commission grandfathering provision. If the Commission truly believes that exempting older transmission pipelines from modern safety standards is "not consistent with [its] obligations to promote the safety, health, comfort, and convenience of utility patrons, employees, and the public," then it must remain steadfast in its determination that all such "historic exemptions must come to an end."[18]

C. There is Insufficient Evidence to Support the Imposition of a Penalty for Lack of Pressure Test Records for Pipelines Installed Between 1956 and 1961.

The Proposed Decision also assumes that under the voluntary industry standards that existed between 1956 and 1961, all transmission pipelines installed between 1956 and 1961 were required to be pressure tested. This is not the case. The voluntary industry standards that existed then did not call for pre-service pressure testing of <u>all</u> pipeline installed during that time. The American Standard Code, as it existed in 1955, provided exceptions to its hydrotesting requirements. For example, hydrotesting was not required where there was a lack of sufficient water to carry out the pressure test because water of satisfactory quality was often not available

[17] *Id.* at 60-61.
[18] D.11-06-017 at 18.

in sufficient quantity to perform such testing.[19] Similarly, the 1955 voluntary industry standard's recordkeeping recommendations, as shown in the table above, only applied to pipelines operated at or above 30% of SMYS.[20] Therefore, if no pressure test documentation exists for a pipeline installed between 1956 and 1961, it is possible—for reasons expressly allowed by the voluntary code provision— that a test was not performed, or that records of such a test were not created.

The Proposed Decision does not take this into consideration when it disallows cost recovery where there is no evidence of a pressure test for a pipes installed from 1956 to 1961. That is in error. Before the Commission imposes a disallowance of pressure testing costs for pipelines installed between 1956 and 1961, it would need to first conduct a segment-by-segment review of the applicable pipelines to determine whether pressure testing of each segment was recommended under the voluntary code <u>at the time of installation</u>, and whether the pipeline segment was intended to operate at 30% or greater of SMYS. Absent such a review, there is insufficient evidence in the record to support the imposition of penalties in the form of disallowances of future pressure testing costs. If no pressure test would have been conducted, no costs for that pressure test would have been recovered in rates.

The Proposed Decision also ignores the fact that the voluntary code was superseded by General Order 112 in 1961. General Orders 112, 112-A and 112-B, under "General Provisions and Definitions," Section 104.3, all expressly state that "[i]t is not intended that these rules be applied retroactively to existing installations in so far as design, fabrication, installation, established operating pressure, and testing are concerned. It is intended, however, that the provisions of these rules shall be applicable to the operation, maintenance, and up-rating of existing installations." Because General Order 112 expressly stated that its provisions were not

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19 *See* ASA B 841.413 ("Requirements of 841.412(c) for hydrostatic testing of mains and pipelines in Location Classes 3 and 4 do not apply if at the time the pipeline or main is first ready for test, one or both of the following conditions exist: (a) The ground temperature at pipe depth is 32°F, or less, or might fall to that temperature before the hydrostatic test could be completed, or (b) Water of satisfactory quality is not available in sufficient quantity.")

20 *See* A.11-11-002, Ex. SCG-17 (Rosenfeld) at 20 ("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.")

to be applied retroactively, once General Order 112 went into effect, and because the 1956 to 1961 Code provisions were entirely voluntary, a pipeline operator may not have retained the original records of pressure tests that pre-dated General Order 112. SoCalGas and SDG&E presented evidence in the TCAP that once the MAOP was established the pressure test record had little operational value.[21]

Denying cost recovery because a pipeline operator does not now have pressure test records for pressure tests conducted under voluntary standards would establish unsound public policy by discouraging utilities from voluntarily complying with industry standards. Indeed, it would also be the first time, to SoCalGas and SDG&E's knowledge, that the Commission imposes a penalty upon a utility for attempting to comply with voluntary standards that were never adopted by the Commission. A pipeline operator should not be penalized for taking a proactive approach to safety.

The Proposed Decision attempts to skirt around this policy implication by basing the decision, in part, on a flawed premise that it would be unfair for customers to pay for more than one pressure test on a particular line.[22] Whether a prior test has been conducted on a particular pre-1970 pipeline is essentially irrelevant from a "double charge" standpoint. Under current Federal Transmission Integrity Management Program (TIMP) regulations, a pressure test is one way to verify the integrity of a transmission pipeline, and if that method is chosen by the operator, it conceivably would require the operator to pressure test the line every seven years to complete reassessment requirements.[23] In fact, SoCalGas and SDG&E have conducted pressure tests on lines as part of TIMP, and the Commission has authorized that funding regardless of the testing history for those lines. It is not unreasonable, in the interest of safety, to ask customers to pay for an additional pressure test after the passage of more than 40 years. The Commission has

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21 *See* A.11-11-002, Ex. SCG-17 (Rosenfeld) at 28-30.
22 *See* Proposed Decision at 60.
23 *See* Title 49 CFR 192.921(a)(2).

directed in D.11-06-017 that a new test needs to occur, and under such circumstances, it is entirely reasonable and fair for customers to pay for the cost of such required testing.

D. The Proposed Decision is Founded Upon Erroneous Recordkeeping Findings

The Proposed Decision quotes the following language in current Federal safety regulations, which exempts older pipelines from modern pressure testing requirements:

> The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding [July 1, 1970].[24]

The Proposed Decision then leaps to the conclusion, without citing evidence in the record, that "[n]o natural gas system operator can comply with these requirements without creating and preserving accurate and reliable system installation, operation, and maintenance records."[25] That is wrong. Validation of an historic operating pressure under Section 192.619(c) does not require system installation records. Rather, 49 CFR 192.619 sets forth criteria to assess or evaluate the pipeline's current condition, operating history, and maintenance history. Regulators have accepted that not all records need to be present or complete and that, under federal law, MAOP for a pipeline can be established for pre-1970 pipelines without any records of a pressure test or even pipe physical attributes. On this point, SoCalGas and SDG&E's witness Mr. Rosenfeld provided testimony:

> 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

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24 Proposed Decision at 98 (quoting 49 CFR 192.619(c). (emphasis added)

25 *Id.*

> records of testing or of pipe physical attributes were not always available.[26]

Because gaps in recordkeeping are not uncommon for pipelines installed 50, 60 and even 70 years ago, Federal regulators have directed their risk management efforts in response to this reality and looked beyond records in determining a pipeline system's operational safety and integrity.[27] Mr. Tenley, another witness for SoCalGas and SDG&E, explained this in his testimony: "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."[28] As further explained by Mr. Tenley:

> 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.[29]

This contrasts sharply with the records-related findings in the Proposed Decision, which appear to be premised on the assumption that natural gas utilities should be held to a standard of perfection with respect to the maintenance of pressure test records over the course of more than half a century; any lost/missing/nonexistent pressure test records, no matter the reason, should automatically require shareholders to pay for pressure testing of the relevant pipeline.

The State's natural gas pipeline operators were not put on notice that a failure to retain such records—even if they were required—would put them at risk for potentially enormous penalties. Such a perfection standard, especially without any prior notice by the Commission, is inconsistent not only with Commission precedent but also with common sense and industry practice. It also does nothing to enhance the safety of the natural gas systems in the State.

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26 *See* A.11-11-002, Ex. SCG-17 (Rosenfeld) at 28.

27 *Id.* at 9-10.

28 A.11-11-002, Ex. SCG-15 (Tenley) at 7.

29 *Id.* at 8.

Perfect recordkeeping is an unrealistic expectation and the passage of many, many years should not be ignored. As explained by Mr. Rosenfeld, "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."[30] Many of the records at issue were created long before the advent of today's sophisticated electronic recordkeeping systems (i.e. the office photocopier was not introduced by Xerox until 1959).

Prior Commission precedent recognizes that "100% compliance with these GOs at all times is not realistic."[31] As explained by the Commission in the context of determining whether to assess fines against an electric utility for violations of the Commission's system maintenance General Orders:

> The purpose of the maintenance requirements of our GOs is not to create an enforcement regime where every failure to comply, no matter how minor, no matter what its cause, no matter whether it has been corrected, puts a utility in jeopardy of substantial daily fines. On the contrary, their purpose is to ensure safe, reliable operation of the electrical system.[32]

Retroactive application of this new perfection standard for pressure test records creates regulatory uncertainty for the State's natural gas utilities. This point was made by SoCalGas and SDG&E's Witness, Dr. David Montgomery,[33] in connection with SoCalGas and SDG&E's Implementation Plan:

> 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.[34]

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30 *See* A.11-11-002, Ex. SCG-17 (Rosenfeld) at 29.
31 D.04-04-065 at 31.
32 *Id.* at 13.
33 Dr. W. David Montgomery is Senior Vice President of NERA Economic Consulting.
34 A.11-11-002, Ex. SCG-14 (Montgomery) at 8.

In turn, such regulatory uncertainty would increase costs for customers by encouraging excessive risk avoidance behavior on the part of the utility, another point made by Dr. Montgomery:

> 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 in the future can lead to excessive avoidance behavior. 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.[35]

Accordingly, rather than drastically change Commission direction without notice, the Commission should affirm its "historic practice of graduated enforcement measures ranging from warnings with an opportunity to make corrections to substantial fines for serious breaches of our rules."[36] As noted by the Commission's Independent Review Panel, this graduated enforcement process is supported by everyone with whom the Panel spoke, because it maintains an atmosphere of cooperation between the regulators and the operators.[37] It also serves a useful deterrence function, by putting the utility on notice that particular conduct, if not remedied, will expose the utility to potential fines or penalties.

E. The Proposed Reduction of the Rate of Return on Equity for Safety Enhancement Projects Would Undermine the Commission's Safety Objectives and Increase Costs Statewide.

The Proposed Decision determines that "PG&E's history of addressing its natural gas transmission pipelines that were installed prior to a pressure testing requirement or for which pressure test records are not available reflects a long-standing avoidance of sound, safety-engineering-based decision-making in favor of financially-motivated nominal regulatory compliance."[38] The Proposed Decision further determines that while "prudence principles do not support a ratemaking disallowance for the costs of needed safety improvements simply due to

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35 *Id.* at 8-9.

36 D.04-04-065 at 11-12.

37 Independent Review Panel Report at 22.

38 Proposed Decision at 106-07.

belated timing, . . .an adjustment to return on equity can be used to address inefficient or ineffective management."[39] Based on these determinations, the Proposed Decision concludes that "PG&E's return on equity for investments made pursuant to the Implementation Plan should be reduced to the cost of debt, currently 6.05%, to reflect PG&E's poor management of its natural gas transmission system."[40] The Proposed Decision assumes this reduced rate of return "will allow PG&E to recover its costs, but no more," and limits the reduction to the first five years "[t]o provide PG&E an incentive to improve its management efforts and to assure shareholders that PG&E gas system safety related capital costs are sound financial investments."[41]

This proposed reduction of the return on equity for safety enhancement projects is misguided and will not achieve the outcomes described in the Proposed Decision. Indeed, the temporary reduction in PG&E's return on equity set forth in the Proposed Decision may undermine the Commission's safety objectives, increase costs for PG&E's customers, and potentially other State utility customers in the long term, discourage capital investment in California at a time when such investment is greatly needed, and violate longstanding legal precedent.

1. Reducing the Return on Equity for the First Five Years that Assets are Placed in Service Will Undermine the Commission's Safety Objectives.

The Proposed Decision determines that a reduction in PG&E's return on equity is justified in light of PG&E's "long-standing avoidance of sound, safety-engineering-based decision-making in favor of financially-motivated nominal regulatory compliance," presumably to encourage PG&E to exercise "sound, safety-engineering-based decision-making" going forward.[42] By singling out PG&E's Implementation Plan capital projects for disparate

39 *Id*. at 107.
40 *Id*. at 108.
41 *Id*.
42 *Id*. at 106-07.

ratemaking treatment, however, the Commission will discourage "sound, safety-engineering-based decision-making" and encourage "financially-motivated nominal regulatory compliance."

A pipeline operator's decision to pressure test or replace particular pipeline segments should be based on sound, safety-based engineering decisions that weigh the potential safety benefits and costs associated with each potential course of action. The Proposed Decision essentially places a thumb on the scale during that process, making replacement a much more costly option for PG&E and its customers. This may discourage PG&E from replacing particular pipeline segments, even where the long-term benefits of replacement would exceed the benefits of pressure testing.

As explained by Dr. Montgomery, an expert witness who testified in support of SoCalGas and SDG&E's proposed Pipeline Safety Enhancement Plan in A.11-11-002:

> A well known theory of the effects of regulation advanced by Averch, Johnson and Wellisz 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.[43]

To encourage sound, safety-based engineering decision-making, the Commission should avoid adopting ratemaking policies that could potentially distort the decision-making process in this manner.

2. Reducing the Return on Equity Will Increase Costs for Utility Customers in the Long Term.

The Proposed Decision acknowledges that "drastically reducing return on equity harms the ratepayers in the long run by increasing borrowing costs and potentially diminishing the financial health of the utility."[44] Nevertheless, the Proposed Decision does just that. As explained by PG&E's expert witness, Susan Tierney, adoption of a reduced return on investment

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43 A.11-11-002, Ex. SCG-14 (Montgomery) at 8 (citing Averch, Harvey; Johnson, Leland L. (1962), *Behavior of the Firm Under Regulatory Constraint*, American Economic Review 52 (5): 1052–1069).

44 Proposed Decision at 107.

rate for Implementation Plan projects could threaten the financial health of the natural gas utility and potentially lead to higher costs for its customers:

> This would place PG&E in a no-win situation: if the company undertook the needed investment, its rates would be insufficient to fully compensate investors. This would create challenges and higher costs for PG&E to attract the capital needed to undertake investments in the first place. This would harm ratepayers by raising the cost of capital built into rates. Consequently, positive investor perceptions about the long-run ability to receive a full return on investment, supported by an allowed ROE that reflects market realities, are necessary to making PG&E competitive in capital markets and allowing it to attract the capital needed to make needed investments. Absent such positive perceptions, a "vicious cycle" can emerge, which becomes further fueled by market participant perceptions regarding regulatory risk from state regulators.[45]

This harm could be avoided by implementing one of many other mechanisms available to the Commission for redressing past conduct, rather than increasing regulatory uncertainty through the imposition of an ongoing reduction of the rate of return.[46] In order to fulfill its statutory obligation to ensure that its safety priority is carried out consistent with the principle of just and reasonable rates, the Commission should avoid adopting ratemaking policies that unnecessarily impose risk on utility customers statewide, when equally effective, yet less risky alternatives are readily available.

3. Reducing the Return on Equity for Safety Enhancement Plan Projects Will Discourage Capital Investment in California.

Although the proposed reduction in PG&E's return on equity for Implementation Plan projects is expressly intended to redress past conduct by PG&E, it could detrimentally impact other utilities in the State by signaling to investors and financial markets that there is an increased regulatory risk in California. As a result, future equity investors may either require higher authorized returns on equity for California utility investments to account for the risk that their returns may be decreased to below the cost for the risk assumed in the investment, or avoid

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45 Hearing Tr. (Tierney) at 1034.

46 Ex. 21 (Tierney) at 2-14-15.

investment in California altogether. This could significantly hinder the ability of other natural gas utilities, including SoCalGas and SDG&E, to implement the Commission's heightened safety standards and drive up the costs to our customers of doing so.

The Commission has acknowledged that achieving its safety goals will require significant capital investment.[47] As explained by Paul Hunt, Southern California Edison's expert, "No rational investor will invest capital in a company where he or she is required to earn a reduced return compared to other similar investments where a full risk-adjusted return is available to be earned."[48] Not only will adoption of this reduced return on equity for PG&E make it more difficult for PG&E to access capital markets to finance these critical investments in pipeline safety, it is also likely to make it more difficult for other regulated utilities in California to access capital markets to finance their safety improvements.[49] In light of the extensive infrastructure investments ordered by the Commission in D.11-06-017, California can ill afford to discourage capital investment in the State.

4. The Proposed Reduced Return on Equity is Unlawful.

In determining a fair and reasonable rate of return, the Commission must comply with the standard set forth by the United States Supreme Court in *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944). In *Bluefield*, the Supreme Court held that a public utility is entitled to rates that will permit it to earn a return on the value of the property equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings that are accompanied by corresponding risks and uncertainties.[50] *Bluefield* further provides that the authorized return should be reasonable and should maintain the utility's ability to support its

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47 *See* D.11-06-017 at 17 ("We understand that the issues at hand implicate substantial expenses and capital investments"). *See also* R.11-02-019 at ("The unique circumstances of PG&E's pipeline records and pipeline strength testing program for its pre-1970 pipeline may require extraordinary safety investments").

48 Ex. 130 (Hunt) at 5.

49 *Id.*

50 *Bluefield*, *supra*, at 692.

credit. The authorized return should also enable the utility to raise the capital necessary for the proper discharge of its public duties.[51] "Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment."[52]

The *Hope* case expanded on the guidelines used to assess the reasonableness of the allowed return. The Court in *Hope* emphasized that revenues must be sufficient to cover capital costs, and declared that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[53]

These criteria have been further approved and refined in additional cases, including *Federal Power Commission v. Memphis Light, Gas & Water Division*, 411 U.S. 458 (1973), *Permian Basin Rate Cases*, 390 U.S. 747 (1968), and most recently in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989). In the *Permian* cases, the Court stressed that a regulatory agency's rate of return order should reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed.[54] Accordingly, the Commission must allow the State's regulated utilities to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks; (2) sufficient to assure confidence in the utility's financial integrity; and (3) sufficient to maintain the utility's creditworthiness and ability to attract capital on reasonable terms.

Adopting a reduced return on equity that is equal to the cost of debt for Implementation Plan projects will likely inhibit the ability of a regulated natural gas utility to recover its costs, since the cost of equity is in fact, merely one component of its overall authorized rate of return. A reduced rate of return for Implementation Plan projects may not allow natural gas operators to attract capital at reasonable terms, as equity investors that are exposed to more business risks will

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51 *Id.* at 693.
52 *Id.* at 690.
53 *Hope*, *supra*, at 603.
54 *Permian*, *supra*, at 72.

not be compensated for these risks. Nor is the reduced return on equity commensurate with returns on investments having corresponding risks.

F. The Proposed Decision Errs by Denying Recovery of Reasonable Contingency Costs.

The Proposed Decision's denial of recovery of any contingency costs whatsoever is unreasonable, not supported by the record, and inconsistent with prior Commission precedent. As described in the Proposed Decision, PG&E's Implementation Plan cost estimates include contingency percentages ranging from 10% to 28%, and average 21% overall.[55] The Proposed Decision states that "DRA opposes PG&E's request for a contingency as 'pre-determined' and based almost exclusively on PG&E's 'judgment' and 'intuition'" and "DRA and TURN presented expert analysis showing that PG&E's cost estimates for pressure testing and pipeline replacement, the largest cost components, greatly exceed the national average and are based on unsupported assumptions drawn from a small sample of such work done on an emergency basis."[56] The Proposed Decision fails to acknowledge that <u>no</u> parties testified that it would be reasonable to eliminate contingency as a cost component of the Implementation Plan altogether.

The Proposed Decision denies PG&E's request for recovery of contingency costs based on three underlying findings. First, the Proposed Decision determines that "DRA and TURN have presented credible testimony that PG&E's pressure testing cost forecasts are already biased to the high end of the expected cost range and thus include an implicit allowance for unexpected cost overruns."[57] Second, the Proposed Decision holds that the Commission's constitutional and statutory duties require the Commission "to create powerful incentives for PG&E to manage [its] program efficiently and to aggressively identify and capture cost savings" and that PG&E would have no such incentive if its request for recovery of contingency costs were approved.[58] Third, the Proposed Decision finds that "the need to do this amount of testing and replacement on an

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55 Proposed Decision at 99.
56 *Id*. at 99-100.
57 Proposed Decision at 101.
58 *Id*.

'urgent' basis has been caused, in part, by PG&E's management of its natural gas transmission system over multiple decades."[59] The Proposed Decision concludes that "having had a role in creating the urgent need for this program, sound ratemaking policy and the public interest support denying PG&E's request to shift the risk of potential cost overruns to ratepayers."[60]

The Proposed Decision errs by characterizing contingency costs as synonymous with cost overruns, and determining that a pipeline operator will have no incentive to efficiently manage its program if it is authorized to recover contingency costs. Although SoCalGas and SDG&E do not offer an opinion with respect to the strength of PG&E's cost estimates, the elimination of contingency in the Proposed Decision altogether is not appropriate and would set bad Commission precedent. Contingency costs are a risk-based allowance for uncertainties or <u>undefined elements</u> of a defined project scope.[61] Hydro testing a pipeline that was placed in service years ago with numerous taps can be a very complex and costly endeavor. This is particularly true in California where operators face strict environmental regulations that can dramatically increase the cost of a project. In the early stages of a project, more uncertainties and undefined elements exist, so contingency costs account for a larger proportion of the total estimated cost of a project as compared to an estimate performed after more engineering, design and execution planning work has been performed. If a project scope includes a larger proportion of contingency costs, this does not mean the early estimate is higher than it would otherwise have been if the scope had been further defined. Rather, dollars allocated to the contingency in the early estimate move into defined areas as greater project definition is realized. Contingency costs therefore reflect essential elements of a project estimate that must be managed via effective cost control and contingency run-down during the project life-cycle.

If contingency costs are arbitrarily limited or outright eliminated from a project budget, funds will not be available to cover those undefined cost elements that will subsequently,

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59 *Id.*

60 *Id.* at 102.

61 Ex. 2 (Caletka/Lechner) at 7-47.

through further project definition, become explicitly defined costs. This will make executing a project within budget increasingly difficult, if not impossible. Although SoCalGas and SDG&E agree that incentives for efficient and cost-effective execution should be considered by the Commission, arbitrary deletion of a fundamental element of a project estimate to incentivize efficiency is not consistent with industry estimating guidelines and practices and is unreasonable.

In addition, the Proposed Decision errs by according undue weight to evidence that PG&E's "cost estimates for pressure testing and pipeline replacement, the largest cost components, greatly exceed the national average and are based on unsupported assumptions drawn from a small sample of such work done on an emergency basis."[62] High level industry average costs did not provide sufficient detail for purposes of comparing those costs to California-specific estimates.[63] Moreover, the large scope of work ordered by the Commission to be completed statewide may lead to a scarcity of essential skilled labor and/or materials, which can further drive up construction costs.

Where this Commission has previously determined that contingency costs were too high, it has adopted a lower rate. For example, in D.10-04-052, a decision approving a request by PG&E to implement a solar photovoltaic program, the Commission noted that PG&E's proposed contingency amounts were higher than what the Commission had approved in other cases and stated, "Rather than adopt PG&E's proposed contingencies, we believe a more reasonable approach is to adopt contingency values that correspond more closely to what we have adopted in other cases. We therefore, adopt an overall contingency amount of 10% consistent with what we adopted for SCE's [solar voltaic program]."[64] Similarly, in D.09-12-044, a decision approving SCE's Tehachapi Renewable Transmission Project (segments 4-11), the Commission declined to adopt SCE's proposed 32% contingency, adopting a contingency of 15% instead.[65]

62 Proposed Decision at 100-01.
63 Ex. 21 (Campbell) at 4-8.
64 D.10-04-052 at 33.
65 D.09-012-044 at 72-73.

In this case, no party offered testimony to support the reasonableness of denying contingency costs altogether. Rather, DRA argued that the proper contingency amount should be set at most at 15%, following further analysis by PG&E, and that "[i]n the absence of a proper contingency analysis based on an updated baseline cost estimate, the Commission should approve a contingency amount of no more than 8%, which is comparable to amounts the Commission has approved for more complicated projects."[66]

The *sua sponte* denial of recovery of all contingency costs recommended in the Proposed Decision is arbitrary, not consistent with the record in this proceeding, and should not be adopted by the Commission. If the Commission determines that an element of PG&E's costs are too high, it should adjust that element accordingly, based on reliable evidence, rather than strike an essential cost element, contingency, from PG&E's cost estimates entirely.

G. The Proposed Decision Errs by Setting an Unreasonable Escalation Rate.

A primary consideration for any infrastructure program of extended duration is the development of an appropriate and consistent model for estimating construction cost escalation. Construction contingency is not meant to address cost escalation on construction projects. Inflation factors are meant to address cost increases associated with the future market-based costs of construction labor, equipment and materials and should be factored in for all construction costs. Any estimate that does not apply appropriate escalation factors to construction costs will be inconsistent with industry practices, incomplete and unrealistic.

For programs spanning multiple years, the appropriate application of cost escalation factors is necessary to establish an achievable budget. The escalation applied should reflect the outlook for the particular materials and workforce utilized for the program. It should also be indicative of the overall activity in the industry and the anticipated competition for resources. Underestimating cost escalation can lead to significant cost overruns on a project of this scale. For example, a four-year, $1 billion construction program can exceed its budget by well over $30

[66] DRA Opening Brief at 110-11.

million, if annual escalation were inappropriately estimated too low at 1.5% and actual escalation turned out to be 3%. Denying cost escalation altogether has even more harrowing effects on a budget. Given the general tendency for construction costs to increase over time with general inflation and the increased demand anticipated in the labor and materials critical to completing the safety work, it is unlikely that prices will remain stagnant over the next four years for these resources. Thus, authorizing inappropriately low escalation or denying authorization for escalation altogether is effectively a penalty as the global market forces of supply and demand are beyond the control of the utility.

III. CONCLUSION

For the reasons set forth above, and the facts established in the record of this proceeding, as well as in A.11-11-002, SoCalGas and SDG&E urge the Commission to revise the Proposed Decision to authorize the recovery of costs for pressure testing pipelines installed after 1956. In addition, SoCalGas and SDG&E request that the Commission refrain from making return on equity adjustments for safety enhancement projects, allow the recovery of contingency costs consistent with prior Commission precedent, and adopt a realistic escalation rate for pipeline enhancement projects.

Respectfully submitted,

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Subject Matter Index of Recommended Changes to the Proposed Decision

Subject Matter Index of Recommended Changes to Proposed Decision	**Citations in Proposed Decision**
Contingency	pp. 63-65, 99-102, COL 33, COL 35
Escalation	pp. 102-03, FOF 37, COL 36
Exemptions to Pressure Testing Requirements	pp. 58-63, FOF 21, COL 18, COL 19,
Pressure Testing Requirements	pp. 58-63, FOF 16, FOF 18, COL 15, COL 16
Recordkeeping Requirements	pp. 58-63, FOF 33,
Return on Equity	pp. 103-08, COL 14, COL 37

Appendix of Proposed Findings of Fact and Conclusions of Law

Proposed Findings of Fact

16. Adopted in 1955, the American Standard Association Code for Pressure Pipeline (ASA B31.8) required pre-service pressure testing for some natural gas pipelines. The pressure testing requirements of ASA B31.8 included exceptions and limitations.

~~18. Since no later than January 1, 1956, PG&E complied with or stated that it complied with industry standards to pressure test pipeline prior to placing it in service. PG&E is unable to produce the records for certain pressure tests that would have been performed in accord with industry standards from January 1, 1956, or for pipeline of unknown installation date. The lack of pressure test records for pipeline placed into service after January 1, 1956, or with an unknown installation date, reflect an error in PG&E's operation of its natural gas system. No evidence was presented that PG&E excluded the costs of pressure testing pipeline from its regulated revenue requirement from January 1, 1956.~~

21. For purposes of prioritization of Implementation Plan projects, a~~A~~ valid pressure test record need only comply with the regulations in effect at the time the test was performed, not later adopted regulations.

37. An escalation rate tied to the overall inflation rate, as proposed by DRA, is not a reasonable escalation factor for Implementation Plan projects.

41. The Proposed Pipeline Safety Enhancement Plan submitted by SoCalGas and SDG&E in this proceeding is under consideration by this Commission in A.11-11-002. Different facts and evidence pertaining to SoCalGas and SDG&E's plan were presented and entered into the record in A.11-11-002.

Proposed Conclusions of Law

14. ~~Because~~ PG&E's proposed cost allocation between shareholders and ratepayers reflects existing ratemaking policies and includes no material voluntary cost allocation to shareholders, notwithstanding the Commission's directive to do so. ~~,~~and dDue to the scope and consequence of PG&E's imprudent management actions, it is reasonable for the Commission to exercise its authority to redress this prior conduct. Intervenors' cost responsibility proposals set forth in this proceeding could, however, distort incentives and increase overall costs for utility customers statewide. Therefore, it reasonable for the Commission to address shareholder responsibility issues through pending investigations into PG&E's conduct, rather than through the ratemaking proposals offered in this proceeding. ~~to use exceptional ratemaking measures when considering shareholders' return on equity.~~

15. It is not reasonable for shareholders to absorb the costs of pressure testing pipeline placed into service after January 1, 1956, or for which PG&E has no known installation date, and for

which PG&E is unable to produce pressure test records. As the Commission explained in D.11-06-017, pressure tests were not required by the Commission until 1961. Moreover, any pressure tests conducted prior to 1970 presumably would not satisfy the Commission's new Subpart J modern standards. Any review of PG&E's recordkeeping for potential shareholder responsibility should consider the individual characteristics of the particular segment in question (*e.g.*, vintage, operating pressure, division or class location), the testing requirement, if any, that applied to that segment at the time it was installed, the circumstances surrounding any missing or incomplete testing records for that segment, and whether such missing or incomplete records make any difference in the test/replace equation.

16. It is not reasonable to adopt~~impose an equitable adjustment to the replacement cost of pipeline installed from January 1, 1956, to July 1, 1961, for which pressure test records are not available, but which require replacement rather than pressure testing. Such an equitable adjustment shall be equal to the forecasted cost of pressure testing the pipeline and shall~~ a reduced rate of return for pipeline safety enhancement projects~~the cost of the pipeline replacement included in rate base and revenue requirement~~.

18. For purposes of prioritization of Implementation Plan projects, a~~A~~ valid record of a pipeline pressure test must include all elements required by regulations in effect at the time the test was conducted.

33. It is ~~not~~ reasonable to adopt ~~cost overrun~~ contingency values that correspond to what we have adopted in other cases. ~~PG&E's imprudent management decisions contributed to risk of such overruns and we adopt cost forecasts at the high end of the range of reasonableness with an added layer for program administration~~.

36. A reasonable rate ~~of 1.5%~~ should be adopted to escalate costs from the effective date of today's decision to the date of project completion.

37. ~~Due to inefficient and ineffective management decisions, PG&E's return on equity for investments made pursuant to the Implementation Plan should be reduced to the incremental cost of debt.~~

39. To comply with the requirement set forth in D.11-06-017 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), all transmission pipeline in California must be subjected to a pressure test that complies with the specifications of 49 CFR Subpart J.

40. The Commission should delay its determination of common issues relating to cost responsibility until the evidence presented by SoCalGas and SDG&E in A.11-11-002 can also be fully considered by the Commission. It would be unfair to SoCalGas and SDG&E, and create an unreasonable and unnecessary possibility of inconsistent Commission decisions, for the Commission to make factual or determinations with respect to issues also currently being considered by the Commission in A.11-11-002 (*e.g.*, the existence, or lack thereof, of pressure testing requirements from 1955-1961). In order to provide for minimum due process, decisions on these common issues can and should be coordinated for all the State's utilities.

41. Because the facts and evidence presented with respect to PG&E's Implementation Plan in this proceeding differ from the facts and evidence presented with respect to the implementation plan of other pipeline operators under consideration in a separate proceeding, this decision may not be cited as precedent with respect to any natural gas pipeline operator other than PG&E.