**BEFORE THE PUBLIC UTILITIES COMMISSION**

**OF THE STATE OF CALIFORNIA**

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| In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority To Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding | ) ) ) ) ) ) | A.11-11-002 |

**PHASE 1 REPLY BRIEF OF**
**SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND**
**SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G)**


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## I. INTRODUCTION

Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) submit this Reply Brief in support of our proposed Pipeline Safety Enhancement Plan (PSEP). In this brief we respond to assertions, arguments, and allegations presented in the Opening Briefs submitted by the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), the Southern California Indicated Producers (SCIP),[1] the Southern California Generation Coalition (SCGC), the Utility Workers Union of America (UWUA), and Southern California Edison Company (SCE). Nothing in intervenors' Opening Briefs ought to alter the conclusion that SoCalGas and SDG&E's PSEP is sound, that the evidence presented in this proceeding is more than sufficient for the Commission to approve that plan and the associated costs, and that these costs are properly borne by ratepayers.

[1] SCIP submitted Phase 1 testimony jointly with Watson Cogeneration Company (Watson). *See* Ex. SCIP-01 (Beach) at 1. However, SCIP's Opening Brief does not indicate that it was also filed on behalf of Watson, and Watson did not file its own Opening Brief. Accordingly, SoCalGas and SDG&E will assume that Watson is not participating in the briefing process.

In evaluating our showing, the Commission should keep in mind that the genesis of our proposed PSEP is the Commission's directive in D.11-06-017 that each of the state's natural gas utilities propose comprehensive transmission pipeline pressure testing plans no later than August 26, 2011,[2] that SoCalGas and SDG&E had limited time to put our proposals together,[3] and that refining any of those numbers would have been a waste of time and resources absent Commission direction on that plan. Accordingly, it is crucial for the Commission to look at not just our initial cost estimates – estimates that may change once we begin the detailed engineering work for each PSEP segment – but also the detailed process and controls that we have proposed to enable us to move forward with this important safety-related work in a timely and cost-effective manner.

SoCalGas and SDG&E recognize that their Opening Brief was a lengthy document that anticipated many of the arguments the intervenors made in their Opening Briefs. For the sake of brevity, we will not repeat ourselves on issues we have adequately addressed in our Opening Brief. Instead, this reply brief will focus on certain fundamental issues that merit further discussion – particularly the questions of potential shareholder responsibility for PSEP costs, and the review and oversight process for PSEP costs. In addition, we will address intervenor arguments regarding certain factual issues when the arguments are new or different from those presented by intervenors in their testimony, or inconsistent with rebuttal testimony or testimony submitted during hearings.

## II. BACKGROUND

Please see our Opening Brief on this topic.

[2] D.11-06-017, mimeo., at 31 (Ordering Paragraph No. 4).

[3] D.11-06-017 was issued on June 9, 2011, allowing SoCalGas and SDG&E a little over two months to prepare their proposal.

## III. RESPONSIBILITY FOR PHASE I COSTS

### A. Applicable Evidentiary Standard and Burden of Proof

#### 1. The PG&E Proposed Decision is not Relevant Evidence

On October 12, 2012, ALJ Bushey issued a proposed decision (PD) in R.11-02-019 regarding the proposed pipeline safety enhancement plan of Pacific Gas and Electric Company (PG&E). In its Opening Brief, TURN contends that in this current proceeding, the Commission *should not* follow the logic of the recently-issued PD in R.11-02-019 when the PD reaches a conclusion that TURN disagrees with (i.e., the PD's conclusion that ratepayers should not receive a new pipeline at no cost), but that the Commission *should* follow the PD's logic when the PD reaches a result that TURN supports (i.e., disallowances for failure to retain records).[4] Likewise, SCIP cites the PD as support for the proposition that the Commission still supposedly permits grandfathering of pre-1970 pipelines that have not been tested to modern standards.[5] These intervenor arguments with respect to the PD in R.11-02-019 are not appropriate. As pointed out in our Opening Brief, "[a] proposed decision is not a decision of the Commission and has no binding legal effect . . ..."[6]

Moreover, it would be unfair to apply Commission orders and determinations regarding PG&E and PG&E's proposed pipeline safety plan to SoCalGas and SDG&E -- particularly orders and determinations involving facts and evidence. SoCalGas and SDG&E are not affiliated with PG&E. We have very different approaches to pipeline maintenance and testing, we have different safety histories, and we have developed our PSEP independently from PG&E's pipeline safety proposals. In addition, the evidence in this current proceeding is very different

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[4] TURN Opening Brief at 35-36.
[5] SCIP Opening Brief at 22-23.
[6] D.11-09-028, mimeo., at 3. *See also* PUC Section 311 ("Every finding, opinion, and order made in the proposed decision and approved or confirmed by the commission shall*, upon that approval or confirmation*, be the finding, opinion, and order of the commission." (Emphasis added.)).

from the evidence presented in R.11-02-019 regarding PG&E's proposed pipeline safety plan.[7] The Commission needs to make its determination regarding SoCalGas and SDG&E's PSEP based upon the record in this *current* proceeding, and not the record established in R.11-02-019.[8]

### 2. General Burden of Proof

A number of intervenors argue that SoCalGas and SDG&E have the burden of proof with respect to our proposed PSEP.[9] As explained in our Opening Brief, SoCalGas and SDG&E agree.[10] This is a ratesetting proceeding, and SoCalGas and SDG&E are the applicants. Applicants in ratesetting proceedings have the burden of proof with respect to their rate increase proposals.

That burden is to establish the reasonableness of our PSEP by a *preponderance* of the evidence, a point on which SCGC and SCIP agree.[11] DRA disagrees, citing a 2001 decision on rehearing relating to an earlier PG&E General Rate Case (GRC) decision, and also briefly referencing an unspecified "2003 decision resolving a water utility General Rate Case."[12] DRA asserts that SoCalGas and SDG&E ought to be required to establish the reasonableness of our PSEP by *clear and convincing* evidence, even though DRA acknowledges that in 2008 the Commission declined to apply the clear and convincing standard to SDG&E's Sunrise Powerlink CPCN application, noting that "the clear and convincing standard has generally been limited to general rate cases and reasonableness reviews which are specialized proceedings."[13] DRA also

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[7] This fact is emphasized by ALJ Long striking, at TURN's request, portions of Mr. Rosenfeld's testimony on the grounds that it related to an argument made in R.11-02-019 but not in A.11-11-002. *See* Tr. at 283-91 (SCG/SDG&E/Rosenfeld).
[8] SoCalGas and SDG&E intend to submit comments regarding the PG&E PD asking, among other things, the Commission to make it explicit that the findings and conclusions in this decision apply only to PG&E and not to any of the state's other natural gas utilities.
[9] DRA Opening Brief at 7; TURN Opening Brief at 13; SCGC Opening Brief at 10; SCIP Opening Brief at 7.
[10] *See* SoCalGas/SDG&E Opening Brief at 16-17.
[11] SCGC Opening Brief at 10, *citing* D.06-05-016 ("Applicants must meet their burden of proof by demonstrating that their positions and proposals are supported by a preponderance of the evidence."); SCIP Opening Brief at 8.
[12] DRA Opening Brief at 8-9.
[13] DRA Opening Brief at 9, citing D.08-12-058, mimeo., at 3.

admits that in SCE's 2009 GRC, the most recent decision DRA cites on this particular topic, the Commission applied a preponderance of evidence standard rather than a clear and convincing evidence standard.[14]

DRA does not attempt to deal with the legal or policy implications of the Commission using a preponderance of evidence standard in Edison's 2009 GRC; instead, DRA simply alleges that this was "error" on the Commission's part.[15] DRA attempts to get around the other problems with its burden of proof argument by alleging that this current TCAP is "both reasonableness review *and* a request for a rate increase."[16] That reasoning fails. This proceeding is not a GRC, and it is not a reasonableness review either. SoCalGas and SDG&E are seeking Commission authorization to make *future* pipeline safety-related expenditures, and one of the (contested) features of our proposal is that there would be no *ex post* reasonableness review of those expenditures. As part of their penalty recommendations, DRA and other intervenors have questioned the reasonableness of SoCalGas and SDG&E's past pressure testing and recordkeeping practices 50+ years ago. But these assertions and allegations are by intervenors, not SoCalGas and SDG&E; they are not a part of our application. SoCalGas and SDG&E are not aware of any Commission precedent requiring a utility to disprove intervenor allegations by clear and convincing evidence.

The Utility Consumers' Action Network (UCAN) filed an application for rehearing of the Commission's decision regarding SDG&E's Sunrise Powerlink (D.08-12-058), claiming, among other things, that the Commission's use of a preponderance of the evidence standard was in error. The Commission disagreed:

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[14] DRA Opening Brief at 10, citing D.09-03-025, mimeo., at 8.
[15] DRA Opening Brief at 10.
[16] DRA Opening Brief at 10.

> According to UCAN, although the standard of review in a CPCN proceeding is a question of first impression, because the CPCN approval will impact utility rates, the clear and convincing evidence standard generally applied in rate cases should be applied. In the Decision, we decline to adopt the clear and convincing evidence standard for SDG&E's application, adopting the more common preponderance standard. UCAN fails to show that the burden of proof is in error.[17]

In reaching this conclusion, the Commission acknowledged that it had applied a clear and convincing evidentiary standard in past GRCs, but expressed doubt as to what the standard actually means:

> We have frequently adopted the "clear and convincing" standard in general rate cases, but as the Decision notes in a footnote, it can be unclear whether the Commission means "clear and convincing" in a lay sense, or is actually adopting the more technical "clear and convincing" standard.[18]

As noted in the California Evidence Code: "Except as otherwise provided by law, the burden of proof requires proof by a preponderance of the evidence."[19] This is the standard that should apply in this proceeding. Under either standard, however, SoCalGas and SDG&E have met our burden.

### 3. Burden of Proof for Penalty Recommendations

As explained in our Opening Brief, when an intervenor proposes a penalty, they have the burden of proving that the penalty is justified.[20] SoCalGas and SDG&E witnesses have explained that the recommendations by DRA, TURN, and other intervenors for "shareholder

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[17] D.09-07-024, mimeo., at 3. This decision was affirmed by the Fourth District Court of Appeal in *Utility Consumers' Action Network v. Public Utilities Com.*, 187 Cal. App. 4th 688, 699-700 (Cal. App. 4th Dist. 2010) ("we defer to the Commission's use of the preponderance of the evidence standard as 'the default standard in administrative proceedings and . . . therefore the appropriate standard for CPCN applications.")

[18] D.09-07-024, mimeo., at 3, *citing* D.08-12-058, mimeo., at 18-19, fn. 28.

[19] California Evidence Code Section 115; *see also* D.09-07-024, mimeo., at 3 *citing* California Administrative Hearing Practice, 2d Edition (2005), 365 (the "preponderance standard is the default standard in administrative proceedings").

[20] *See* SoCalGas/SDG&E Opening Brief at 17 (*citing* D.87-12-067, mimeo., at 297-98; D.96-08-033, mimeo., at 19.

responsibility" and "disallowances" are in reality proposed penalties.[21] For example, DRA recommends that shareholders be responsible for $1.603 billion (96%) of Phase 1A direct costs, while TURN proposes that shareholders pay for $274 million of Phase 1A direct costs. As Mr. Morrow pointed out in his rebuttal testimony, even TURN's recommendation would constitute the largest penalty in Commission history.[22]

DRA's response is to characterize our position on this topic as either a "genuine misunderstanding" or a "deliberate mischaracterization."[23] TURN asserts that "[n]otwithstanding the fact that TURN and other parties first raised the Sempra Utilities' imprudence in their responsive testimony, the Commission needs to keep in mind that the Sempra Utilities ultimately bear the burden of proof on this issue."[24]

There is no "misunderstanding" or "mischaracterization" on SoCalGas or SDG&E's part. A party such as TURN who proposes a penalty in a Commission proceeding bears the burden of justifying that proposed penalty. Just because an intervenor chooses to call the penalty recommendation a proposal for "shareholder responsibility" or "disallowance" doesn't mean that it isn't really a proposed penalty. The Commission should look beyond the *form* of intervenors' proposals (or, rather, the vehicle by which the recommendations would be implemented), and instead focus on the *substance*. The *substance* of each intervenor proposal for "shareholder responsibility" or "disallowance" is clearly to punish SoCalGas and SDG&E for alleged past bad conduct. These particular intervenor proposals have everything to do with conduct that occurred many decades ago, and nothing to do with the substance of the future PSEP work that we have proposed in this proceeding.

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[21] *See* SoCalGas/SDG&E Opening Brief at 17-19.
[22] *See* Ex. SCG-13 (Morrow) at 5.
[23] DRA Opening Brief at 22.
[24] TURN Opening Brief at 16.

The proposals from intervenors for "disallowances" of such future expenditures are not premised upon SoCalGas or SDG&E overspending on pipeline safety work, or making expenditures that the Commission does not approve of – ultimately we will do as much or as little PSEP-related work as the Commission authorizes. Instead, the intervenor "shareholder responsibility" and "disallowance" recommendations for future PSEP expenditures are based upon the theory that utility shareholders should be financially punished whenever SoCalGas and SDG&E are unable to produce a pressure test record from the 1960s or earlier.

As pointed out by SCE in its Opening Brief, the Commission has stated that "[p]enalties are punishments for offenses or actions contrary to statute, order, rule, instruction, or express policy."[25] In contrast, disallowances are "denials of rate recovery for unreasonable costs."[26] Intervenors are clearly proposing penalties to punish SoCalGas and SDG&E for alleged past bad conduct (i.e., failure to keep records and failure to conduct pressure tests) that intervenors claim are contrary to the Public Utilities Code and Commission regulation.

The costs in question – proposed future O&M and capital expenditures – have not been incurred, so there can be no question yet regarding their reasonableness. Given these circumstances, the intervenors should have the burden of proving that their proposed penalties are justified.

#### 4. Any Consideration of Recordkeeping Penalties for SoCalGas and SDG&E Should Take Place Outside of Phase 1, and in a Manner that Provides Due Process

SoCalGas and SDG&E explained in our Opening Brief that penalties are serious business, particularly penalties of the unprecedented magnitude being recommended by

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[25] SCE Opening Brief at 5 (*citing Re Southern California Edison Co.,* D.91-12-076, 1991 Cal. PUC LEXIS 911 at *256, 42 CPUC2d 645, 130 P.U.R.4th 97).

[26] SCE Opening Brief at 5 (*also citing Re Southern California Edison Co.,* D.91-12-076, 1991 Cal. PUC LEXIS 911 at *256, 42 CPUC2d 645, 130 P.U.R.4th 97).

intervenors.[27] Penalties should not be a sideline in a proceeding focused on the forward-looking plan "to achieve the goal of orderly and effectively pressure testing all natural gas transmission pipeline that have not been pressure tested."[28] As Dr. Montgomery accurately summarized:

> The Commission said it wants a timely response. And this is either a good plan for moving forward and … should be accepted or it's a bad plan for moving forward and should be rejected. But neither of those has anything to do with whether there should be a penalty on something that happened 40 years ago.[29]

Our document review efforts in connection with PSEP have been focused on determining whether we have pressure test records that give us enough comfort to rely on for the purpose of prioritizing pipeline safety work.[30] We have not been reviewing past records with an eye towards determining whether we have records that, even though they do not give us sufficient comfort to place a segment lower in the testing/replacement queue, might arguably satisfy a past industry standard or Commission requirement.

SoCalGas and SDG&E have been operating under the assumption that the Commission is in fact eliminating "grandfathering" for *all* pre-1970 pipelines, and that Ordering Paragraph No. 4 in D.11-06-017 really means what it says. As such, we did not conduct a compliance review to determine whether a pressure test record met some earlier, out-of-date standard."[31] A document establishing compliance with earlier regulations is essentially a historical artifact.

If in fact "grandfathering" of certain pre-1970 pipelines is alive and well, as certain intervenors proclaim, SoCalGas and SDG&E deserve an opportunity to conduct a compliance review of our pre-1970 records. As explained by Mr. Schneider during hearings, we may have records of certain pipelines being tested to 1.1 time MAOP per B31.8, but we still included those

[27] SoCalGas/SDG&E Opening Brief at 21.
[28] D.11-06-017, mimeo., at 1.
[29] Tr. at 759 (SoCalGas/SDG&E/Montgomery).
[30] Tr. at 397-99 (SoCalGas/SDG&E/Schneider).
[31] D.11-06-017, mimeo., at 31 (Ordering Paragraph No. 3).

pipelines in Category 4 because the testing was not done to 1.25 times MAOP screening standard SoCalGas and SDG&E used.[32] Likewise, we may have records that would technically satisfy the regulations in place when the test was conducted, but we were conservative on determining whether the record was sufficient to justify not testing in the post-San Bruno environment:

> And so there are some records where there's basically a handwritten note or maybe there's other documentation we have. We have documentation that indicates what the test pressure was. But we felt in this post San Bruno era, we wanted to be conservative, so we put those miles into category four as well.
>
> . . .
>
> . . .we weren't really thinking about compliance . . .. We weren't thinking about the code requirements. We were thinking strictly of, okay, what are we trying to learn about what happened at San Bruno, how do we identify these pipelines where we're going to take additional action.[33]

SoCalGas and SDG&E have so far focused our record review efforts on safety, not on potential cost responsibility arguments. Under these circumstances, it would be unfair -- and would in fact deny SoCalGas and SDG&E due process -- to make any penalty-related determinations based upon the limited recordkeeping record to date in this proceeding.

To properly assess the need for, and fairness of, a potential recordkeeping penalty, the Commission would need to carefully examine 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, 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. The Commission would then need to consider the proposed recordkeeping penalties in a forum that allows it to weigh a proposed penalty

[32] *See* Tr. at 430-31 (SoCalGas/SDG&E/Schneider).
[33] Tr. at 398 and 410 (SoCalGas/SDG&E/Schneider).

against the purported infraction, and compare the proportionality of the two against past penalties levied by the Commission.

In its Opening Brief, SCE recommends the imposition of penalties *only* if it furthers the Commission's goal of increasing public safety.[34] Penalties for alleged recordkeeping failures that occurred many decades ago, and alleged failures to initially pressure test pipelines that have been safely and reliability providing public utility service for more than half a century, would do nothing to increase public safety especially where, as here, the gas utilities in question have excellent operating histories.

Despite all of the rhetoric from intervenors, SoCalGas and SDG&E's inability to locate pressure test records for our pre-1970 transmission pipelines – records that may or may not have existed or been required -- does not merit the imposition of penalties, especially in light of the safe operations of SoCalGas and SDG&E as a whole (which should take primacy over a test record when evaluating system safety), technological changes over the past 80 years (which make accessing historical information both difficult and costly), the absence for many years of specific directives on recordkeeping by the Commission, and the fact that SoCalGas and SDG&E did not financially benefit from failing to keep every pressure test record for every one of our pipelines.[35] But if a penalty for any specific alleged past recordkeeping or pressure testing "failures" is warranted -- and we strongly believe that it is not -- the penalty should be considered as part of another proceeding (or perhaps another phase of this proceeding) in which the parties proposing penalties have the burden of proof, and the focus of the proceeding is solely on the recordkeeping penalty recommendations. Again, as Dr. Montgomery explained:

> I think you should be accepting their Application because the Commission wants a timely response to approve the safety, and it's

[34] SCE Opening Brief at 6.
[35] *See* Ex. SCG-14 (Montgomery) at 7.

> got to be done. If you believe that the penalty is appropriate for -- that a penalty today is appropriate for failures 30 or 40 years ago to maintain the records, then that's something separate. But it is entirely separate, I think, from a . . . plan to move forward now to improve safety and recover the costs of doing that.[36]

### 5. Section 463 is not Applicable to Our PSEP Proposals

Certain intervenors argue that California Public Utilities Code section 463 requires the Commission disallow PSEP costs.[37] These arguments are overbroad and misplaced.

Section 463 (added to the Public Utilities Code in 1985) applies to additions of capital plant in excess of $50 million, and requires the Commission to review the reasonableness of a utility's management of and expenditures on the project and disallow, if applicable, project expenditures that result from "unreasonable error or omission related to the planning, construction, or operation" of the project "including any expenses resulting from delays caused by any unreasonable error or omission." Several of the key terms in the statue are defined, including "error" and "omission":

> (c) For purposes of this section:
>
> . . .
>
> (4) "Error" includes, but is not limited to, any action or direction which causes an avoidable (i) increase in the time required to bring the plant to full commercial operation, (ii) change in the number or types of personnel or firms required to bring the plant to full commercial operation, (iii) increase in the number of worker hours required to complete any portion of the plant construction project, or (iv) change of equipment, configuration, design, schedule, or program.
>
> (5) "Omission" includes, but is not limited to, any failure to act or to provide direction which causes an avoidable (i) increase in the time required to bring the plant to full commercial operation, (ii) change in the number or types of personnel or firms required to bring the plant to full commercial operation, (iii) increase in the number of worker hours required to complete any portion of the

[36] Tr. at 758-59 (SoCalGas/SDG&E/Montgomery).

[37] *See* SCIP Opening Brief at 9; UWUA Opening Brief at 22-24; TURN Opening Brief at 31.

> plant construction project, or (iv) change of equipment, configuration, design, schedule, or program.[38]

It is clear from these definitions that the focus of this statute is *new* construction, not construction that occurred at least 15 years before this statute was even enacted. In fact, the statue – a result of PG&E's "mirror image" problem at Diablo Canyon[39] – only applies to capital additions in excess of $50 million. Moreover, this statute does not apply to *related* projects that together total more than $50 million (such as most of our Phase 1A PSEP projects), if the individual projects themselves are each less than $50 million.[40]

Intervenors also point to the phrase in Section 463(b) -- "fails to prepare or maintain records" -- in an effort to bring historic recordkeeping practices within the scope of the Section 463.[41] That effort, again, falls short. As the italicized language below indicates, this "records" requirement only pertains to records documenting the costs incurred on the planning, construction or operation of the specific capital asset over $50 million *that is under review*:

> Whenever an electrical or gas corporation fails to prepare or maintain records sufficient to enable the commission to completely evaluate any relevant or potentially relevant issue related to the reasonableness and

[38] Public Utilities Code Section 463(c)(4) and (5).
[39] As the Legislature explained in implementing Section 463: "The Public Utilities Commission, in its final order and decision in the application of Pacific Gas and Electric Company for an increase in rates reflecting expenses related to the construction of that project known as the Diablo Canyon Nuclear Power Plant, if the commission determines that the company shall be allowed to earn a return on underappreciated capital costs related to the project shall make specific findings as to those costs, if any, including resulting from delays, directly or indirectly related to…(2) the questionable use of blue prints, commonly known as the 'mirror image' problem, together with any other issues related to the adequacy of the quality assurance program which may have been revealed subsequent to the discovery of the 'mirror image' problem. The Commission shall, in addition, make specific findings as to whether or not any of these matters constitute errors or omissions under Section 463 of the Public Utilities Code…This section does not apply if the commission establishes the rates for the Diablo Canyon Nuclear Power Plant on a basis other than an allowed rate of return on undepreciated capital costs." *See* Stats. 1985, ch. 1212, section 2.
[40] *See* D.87-12-066, mimeo., at 434 (Conclusion of Law No. 61) (Appendix A – adopted as reasonable by the Commission- contains joint procedures proposed by Edison and PSD and states: "The modifications being implemented under the ILS program comprise numerous distinct and individual projects. The individual SONGS 1 ILS plant additions for Fuel Cycles IX, X, and XI are each less than $50 million, and therefore PUC Section 463 is not applicable to them.").
[41] *See, e.g.*, UWUA Opening Brief at 23; SCIP Opening Brief at 9.

> prudence *of any expense relating to the planning, construction, or operation of the corporation's plant*, the commission shall disallow that expense for purposes of establishing rates for the corporation. This subdivision does not apply where the commission determines that a reasonable person could not have anticipated either the relevance or potential relevance, *to an evaluation of costs incurred on the project*, of preparing or maintaining the records or the extent of recordkeeping required *to adequately evaluate those costs*.[42]

There is currently no recordkeeping issue for the Commission to decide with respect to SoCalGas' and SDG&E's proposed PSEP-related capital projects. If SoCalGas or SDG&E are authorized to move forward with our proposed PSEP projects, *and* if one or more of the authorized individual projects involves expenditures of more than $50 million, *and* if SoCalGas or SDG&E fails to maintain records *relating to the new construction* that are adequate to enable the Commission to evaluate the reasonableness and prudence of the new construction, then Section 463(b) could potentially be implicated.[43] But this particular statutory requirement has no place in the current discussion regarding our proposed but unconstructed pipeline segments.

In an effort to avoid the plain language of Section 463(b), intervenors appear to argue that somehow records relating to the pre-1970 pipelines disqualify *new* construction from rate recovery under Section 463(b). Such contorted logic makes no sense. Records (or lack thereof) relating to existing pre-1970 pipelines have no more place in a Section 463(b) review of new pipeline construction than do, for example, records relating to past performance of a utility's fossil generation plants in a 463(b) review regarding the cost to construct a new nuclear facility. In fact, if intervenors' 463(b) arguments were taken to their logical conclusion, the review of every new large capital asset constructed by a utility in California would potentially involve a

[42] Public Utilities Code Section 463(b)(emphasis added).
[43] Even then, however, Section 463(b) may not apply. Section 463.5 provides that Section 463 does not require the Commission to undertake a reasonableness review of large capital projects when the Commission has established a maximum reasonable cost for the project pursuant to Section 1005.5 (CPCN), or adopted an estimate of the reasonable costs in any proceeding.

painstaking review of a huge volume of documents that have no relationship to the construction itself, but may have some alleged tangential relationship to the need for the new construction (*e.g.*, "We need to look at all of your generation unit operating records for the last 50 years; if you had just not run the old generation units so hard over the years, you might not need one now." "No plant employment records from the 1950s? Without them, the Commission cannot determine if you were properly maintaining the old substation that is being replaced.") Clearly this is not the sort of records evaluation contemplated by the Legislature when it enacted Section 463(b).

### B. Transmission Pipeline Testing and Record-Keeping Requirements and Standards

Please see our Opening Brief on this topic.

### C. Cost Responsibility

Several intervenors have proposed, to varying degrees, shareholder responsibility for PSEP costs.[44] In particular, DRA recommends that if a reliable record of a pressure test cannot be produced, SoCalGas and SDG&E's shareholders be entirely responsible for all expenses associated with hydrostatic testing pipelines installed from 1935 to the present, responsible for all expenses of testing or replacing pipelines installed during or after 1955, and that the Commission should adjust the return on equity or fashion its own adjustment for pipelines replaced between 1935-1955.[45] TURN recommends that shareholders be responsible for all costs for post-1955 pipe segments which would not have been incurred had SoCalGas and SDG&E adhered to regulations and standards.[46] SCGC and SCIP recommend that shareholders

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[44] On the other hand, SCE opines that because the Commission asked SDG&E and SoCalGas for a plan to implement and fund future safety improvements, the costs of doing so should be recoverable. SCE Opening Brief at 9.
[45] DRA Opening Brief at 21-22.
[46] TURN Opening Brief at 13.

be responsible for all costs for post-1961 pipe segments that would not have been incurred had SoCalGas and SDG&E adhered to GO 112.[47]

Each of these intervenor arguments for shareholder PSEP cost responsibility are unreasonable and ill-conceived.

### 1. SoCalGas and SDG&E have Safe Natural Gas Transmission Systems

Despite unfounded intervenor assertions to the contrary, SoCalGas and SDG&E have safe natural gas systems. We have not had an event like the 2008 Rancho Cordova explosion in PG&E's service territory, and we have never experienced a tragedy like the 2010 pipeline disaster in San Bruno. As the Independent Review Panel on the San Bruno pipeline rupture observed, the San Bruno catastrophic explosion is a rare occurrence that is not indicative of other transmission system operators such as SoCalGas and SDG&E:

> [T]he natural gas infrastructure in North America, with all of its imperfections, represents a stable system. It is designed and built with a margin of safety so it should not fail without warning. A catastrophic incident such as the San Bruno tragedy is, therefore, a rare occurrence. In general, industry standards and government regulations are already designed to ensure the margin of safety will not be compromised to a point where there is a likelihood the pipeline will fail. What we have in the San Bruno situation is one operator, PG&E, who did not properly account for the threat of failure of a section of pipeline system and hence did not take appropriate remedial action.[48]

SoCalGas and SDG&E realize that the lack of tragic explosions involving our facilities is not a conclusive indication of our safety, and that we cannot be complacent where safety is concerned. We know that we must work diligently each and every day to try to provide the safe and reliable natural gas service our customers deserve.

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[47] SCGC Opening Brief at 8-9; SCIP Opening Brief at 11.

[48] Independent Review Panel Report on San Bruno Pipeline Explosion (Independent Review Panel Report) at 28, Rec. 5.5.3.2., filed June 9, 2011, in R.11-02-019 and entered into the record of A.11-11-002 by *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* on April 17, 2012.

SoCalGas and SDG&E "walk the talk" when it comes to pipeline safety, and we were doing so long before the San Bruno explosion elevated pipeline safety in everyone's consciousness. SoCalGas and SDG&E have long been at the forefront of implementing new inline inspection technologies, and we have developed a prudent pipeline safety program based on extensive retrofitting of existing pipelines and internal inspection of its gas system using "smart-pigs." In fact, as of December 2010, we had completed baseline assessments for 63% of our pipeline segments in High Consequence Areas (15, 833 miles) using smart pigs.[49] This contrasts with the PG&E pipeline integrity plan that called for a total of 208 miles (20%) of High Consequence Area miles to be completed using inline inspection.[50]

Likewise, in the mid-1980s SoCalGas initiated a special pipeline replacement program focused on non-state of the art infrastructure that presented elevated risk to public safety.[51] 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.[52] When this program was completed in the mid-1990s, 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.[53]

An additional measure of the safety-first culture at SoCalGas and SDG&E is our continued strong record of compliance in safety-related audits by the Commission's Consumer

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[49] Ex. SCG-16 (Stewart) at 4.
[50] Ex. SCG-16 (Stewart) at 4. *See also* Independent Review Panel Report at 12-13 ("Only 21 percent of PG&E's system is able to utilize in-line inspection. Yet, PG&E has substantial pipeline mileage in HCA's, which makes the significance of being able to inspect its system with the best available technology particularly important").
[51] Ex. SCG-16 (Stewart) at 3.
[52] Ex. SCG-16 (Stewart) at 3.
[53] Ex. SCG-16 (Stewart) at 3.

Protection and Safety Division (CPSD). 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.[54] As Mr. Stewart explained:

> 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. It is evident that SoCalGas takes seriously its compliance responsibility.

Another example of our strong commitment to safety is the systematic approach initiated by SoCalGas in the 1990s 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.[55] 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.[56] By enhancing the performance of pipelines crossing earthquake faults through 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.[57]

In addition, SoCalGas and SDG&E have implemented robust Integrity Management Programs as a supplement to our long-standing routine safety and maintenance practices.[58] These integrity management programs have significantly increased the level of preventative and

[54] Ex. SCG-16 (Stewart) at 2.
[55] Ex. SCG-16 (Stewart) at 3.
[56] Ex. SCG-16 (Stewart) at 3.
[57] Ex. SCG-16 (Stewart) at 3-4.
[58] Ex. SCG-18 (Schneider) at 20.

mitigative activities on our pipeline system as part of ongoing assessments (i.e., as inline inspections, direct assessment, and integrity-related pressure tests).[59] 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.[60] In cases where background information is unavailable, or cannot be supplemented with reliable sources or institutional knowledge, more conservative default values are used.[61] 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).[62]

Our commitment to safety can even be seen in our approach to reviewing documents in connection with the NTSB's safety recommendations. Rather than review records with an eye toward compliance, we undertook a review with an eye toward safety by asking the question: Sitting here today, are we comfortable that there is sufficient documentation to validate at least a 1.25 MAOP safety margin based on a post-construction pressure test? If the answer to that question was "no," we categorized the pipeline segment as "Category 4," even if there was some documentation of a pressure test.[63]

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[59] Ex. SCG-18 (Schneider) at 20-21.
[60] Ex. SCG-18 (Schneider) at 21 referencing 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.
[61] Ex. SCG-18 (Schneider) at 21.
[62] Ex. SCG-18 (Schneider) at 21.
[63] Tr. at 402-403 (SoCalGas/SDG&E/Schneider).

### 2. Lack of Pressure Test Documentation for a few Pipelines Installed 40+ Years Ago is not Equivalent to a Lack of Safety

According to TURN, "It is simply not fair to expect ratepayers to foot the bill for the Sempra Utilities' *safety-threatening* lapses in documenting the MAOP of their pipelines."[64] UWUA characterizes missing pressure test documentation as a "fundamental service deficiency."[65] SCIP explains the connection between pressure test documentation and safety as follows: "the regulatory compact does not support 100% cost recovery if Sempra cannot demonstrate that it has fulfilled its statutory obligation to provide safe service . . . SCIP's disallowance recommendations are specifically tied to Sempra's statutory obligation to provide safe and reliable natural gas service . . . ."[66] DRA asserts that "it now appears . . . the Sempra Utilities have failed to operate or maintain their systems prudently . . . ."[67] DRA also contends that "it is, or should be, obvious that to operate safely, a natural gas utility should maintain records relating to the original cost of its pipelines, and any 'additions or betterments' made to them."[68]

Each of these intervenors equate pressure test documentation (and, in DRA's case, accounting documentation regarding pipeline costs), with safety. According to this line of thinking, if a utility misplaces a pipeline-related document from 40+ years ago, the utility's system is unsafe and the utility is an imprudent operator. This reflexive argument may be appealing to intervenor attorneys intent on promoting an anti-utility agenda. But it is not consistent with common sense or real-world practice.

[64] TURN Opening Brief at 18 (emphasis added).
[65] UWUA Opening Brief at 20.
[66] SCIP Opening Brief at 16-17.
[67] DRA Opening Brief at 2.
[68] DRA Opening Brief at 18.

Simply put, lack of a documented pressure test does not equate with lack of safety, just as the existence of a pressure test document doesn't guarantee safety. Pressure test documents can be an important part of the overall safety equation, certainly.[69] But initial pressure tests, if they were conducted at all, become much less important over time. In fact, as Mr. Rosenfeld pointed out, "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."[70] Moreover, as Mr. Tenley has explained, pressure test records are not the panacea that DRA and TURN make them out to be:

> 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

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[69] The connection DRA attempts to make between cost accounting documents and safety decades later is simply puzzling. Such documents might well have been relevant in a 1946 GRC when SoCalGas (or one of its predecessor companies) first sought to add a particular pipeline to rate base. But, at least from a pipeline operator's standpoint, there is no safety-related use for such documents.

[70] Ex. SCG-17 (Rosenfeld) at 28-29.

regulations in a vacuum. The Commission should decline to do so.[71]

For these reasons, intervenor safety-related arguments are unfounded. As explained above, SoCalGas and SDG&E are safe transmission system operators. The fact that we are unable to find historic pressure test documentation for a few very old pipelines – documentation that would have very limited relevance from an operational standpoint anyway – does not somehow turn our historically safe operations into "safety-threatening lapses," "fundamental service deficiencies," and the like.

**3. The Commission should not retroactively create a Pressure Testing Requirement for Pipelines from 1935 through 1961**

As noted above, DRA and TURN argue that SoCalGas and SDG&E should be responsible for the costs of testing or replacing pipelines installed from 1935 through 1961. The underlying premise for these arguments is that SoCalGas and SDG&E allegedly had an obligation to pressure test pipelines during these time periods, and to retain records of such pressure testing.[72]

As explained in detail in our Opening Brief, these arguments are unfounded.[73] There were no state or federal requirements for pressure testing from 1935 through 1961, just voluntary guidelines (1935-1955) and voluntary industry standards (1955-1961) that SoCalGas and SDG&E were *not* required to follow. It would be unreasonable and unfair to financially punish SoCalGas and SDG&E in 2013 and future years for failing to conduct pressure tests from 1935-1961 (or to retain records from such tests) when we weren't required to do the tests in the first place. Could the Commission have punished us in 1940 or 1957 for not pressure testing a new pipeline? Certainly not – there was no requirement for us to violate. As the Commission's

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[71] Ex. SCG-15 (Tenley) at 7.
[72] *See* DRA Opening Brief at 19-22; TURN Opening Brief at 21-23.
[73] *See* SoCalGas/SDG&E Opening Brief at 42-46.

Safety Division explained in a recent filing in the ongoing Fire Safety OIR: "Standards are generally recommendations and contain language such as "may" and "should"; they are not binding and are not written to be enforceable law."[74]

In its Opening Brief, TURN argues that SoCalGas and SDG&E should be financially penalized for helping to develop, and then following, new voluntary industry pressure testing standards: "because the Sempra Utilities acknowledge that they voluntarily adhered to the 1955 standards and in fact participated in the development of those 1955 standards, there can be no dispute that those standards are an appropriate yardstick against which to measure the prudence of the Sempra Utilities' behavior."[75] This argument turns logic on its head. Under TURN's twisted theory, SoCalGas and SDG&E would be much better off if they had not voluntarily labored to improve industry safety back in the 1950s, and instead said "Nope, until the Commission specifically orders us to implement pressure testing, we aren't going to consider it." In fact, under TURN's rationale, we would be better off leaving steel pipe and other antiquated assets in the ground, since replacing weak links in our systems might somehow create a new "requirement" that we could be penalized for not observing.

The message that would be conveyed by the Commission (or any regulator, for that matter) financially penalizing SoCalGas and SDG&E for their voluntary efforts to improve pipeline safety -- both in California, and throughout the nation through participation in the development of new industry standards -- would be horrific. Simply put, utilities should never be penalized for taking a proactive approach to safety.

TURN does not cite a single Commission decision or other precedent for the proposition that new regulatory requirements can spring from utility conduct. This does not surprise us. We

[74] R.08-11-005, CPSD's October 23, 2012 Opening Comments on Phase 3 Technical Panel Reports, at p. 7.
[75] TURN Opening Brief at 15.

are not aware of any such precedent, and the fundamental premise of TURN's argument does not make sense. If, for example, a taxpayer generally files their tax returns in February when they receive their W-2s, may the IRS penalize them in a later year for waiting until April 15 to file? Of course not; April 15 is the statutory filing deadline, and that deadline does not change for particular taxpayers because of their particular filing habits. Likewise, new regulatory requirements cannot spring up out of utility conduct.

DRA and TURN's 1935-1961 penalty arguments are for the most part premised upon the Commission establishing a new, retroactive pressure testing requirement 50-85 years after the lines in question were first put into service. The Commission should resist these requests to illegally infringe on our rights in this manner.[76]

TURN also makes an additional "equity" argument for holding SoCalGas and SDG&E responsible for PSEP costs. According to TURN, it would be unfair for customers to pay for more than one pressure test on a particular line.[77] But this argument is also fatally flawed. First, if a pressure test was not originally conducted on a pipeline, of course there can be no double charge for testing. Second, even if a pressure test was in fact conducted when one of these pre-1970 lines was originally placed into service, the test would have taken place no less than 42 years ago. It is not unreasonable, in the interests of safety, to ask customers to pay for an additional pressure test after the passage of more than 40 years. Moreover, under our TIMP program a pressure test is one way to verify integrity of a transmission pipeline, and if that method is chosen by the operator it conceivably would require the operator to pressure test the

[76] "A regulation cannot be applied retroactively where such application will result in taking property without due process of law." 2 Cal. Jur. 3d Administrative Law § 329 *citing La Com v. Pacific Gas & Elec. Co.* (1955) 132 Cal. App. 2d 114 (holding rule requiring electrical poles and wires near airports to be marked not applicable to poles and wires erected prior to construction of airport).
[77] TURN Opening Brief at 34-35.

line every seven years to complete reassessment requirements.[78] 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. Third, as noted elsewhere in this brief, none of our past pressure tests satisfy the Commission's new Subpart J "modern standard." Accordingly, whether or not a prior test has been conducted on a particular pre-1970 pipeline is essentially irrelevant from a "double charge" standpoint. The Commission has directed 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.

#### 4. The Commission should not adopt a New Retroactive "Perfection" Standard for Recordkeeping

The records-related penalty arguments by intervenors are premised on the assumption that SoCalGas and SDG&E are required to have maintained perfect pressure test records over the course of more than half a century, and that any lost/missing/nonexistent pressure test records should automatically require shareholders to pay for pressure testing or replacement of the relevant pipeline. As DRA summed up, "When the Commission asked the Sempra utilities to demonstrate that they had pressure tested their lines, or present a Plan for doing so, '. . . the answer should have been: test records are available; the cost is zero dollars.'"[79] Likewise, TURN argues that there is no possible justification for failure to keep perfect records.[80] These absolutist positions with respect to recordkeeping are inconsistent with common sense, industry practice, and Commission precedent.

Perfect recordkeeping is a new and unrealistic expectation, particularly given that we are dealing with many records created long before the advent of today's sophisticated electronic

[78] Title 49 CFR 192.921(a)(2).
[79] DRA Opening Brief at 18 (quoting hearing testimony of DRA witness David Peck).
[80] *See* TURN Opening Brief at 14-15.

recordkeeping systems. The Commission should keep in mind that the documents in question come from a very different era (the office photocopier was not introduced by Xerox until 1959), and have limited operational relevance once MAOP is established. Moreover, we are dealing with the passage of many, many years. As Mr. Rosenfeld explained: "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."[81]

In addition, even if hydrostatic pressure tests were conducted during this era, SoCalGas and SDG&E were not required to retain records of these tests, nor were we put on notice that a failure to retain such records would have potential negative consequences. As acknowledged by DRA,[82] the recommendation to keep any hydrostatic pressure test records did not appear in the ASA until 1955 (and even then it only applied to those pipelines operating at that time above 30% SMYS). In fact, nothing contained in the ASA prior to 1955 required the operator to create (much less maintain) a record of a pressure test.

DRA alleges that GO 28 required SoCalGas and SDG&E to indefinitely retain records associated with hydrostatic testing since its inception in 1912.[83] When GO 28 was implemented in 1912, however, it was implemented to promote the preservation of records "supporting each and every entry in the following general books" including the accounts payable ledger, accounts receivable ledger, general and auxiliary ledgers, journals and cash books, annual reports and records pertaining to the "original cost," and "depreciation and replacement" of property, equipment and plant.[84] The only references to "equipment and plant" records are those

[81] Ex. SCG-17 (Rosenfeld) at 29.
[82] Ex. DRA-01 (Peck) at Attachment 1, page 11.
[83] DRA Opening Brief at 16-17.
[84] GO 28, mimeo., at 1.

"pertaining to depreciation and replacement."[85] Meaning, GO 28 is an accounting document preservation requirement. It assumes that the utility has created an accounting record and, once created, the accounting record comes within GO 28's preservation rules. Records related to pressure testing, however, are operational in nature and have never been considered accounting records.[86]

Perfect recordkeeping for pre-1970 pressure test records is clearly not an industry practice or expectation. As explained by Mr. Rosenfeld:

> 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.
>
> . . .
>
> 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.
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> That gaps could exist in an operator's records does not automatically mean the operator is imprudent or irresponsible

[85] Ex. SCG-13 (Morrow) at 7.
[86] Ex. SCG-13 (Morrow) at 7.

> (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, 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.[87]

In a decision cited favorably by TURN, the Commission pointed out that it evaluates utility conduct "in light of the facts known or which should be known at the time the decision was made."[88] Likewise, Public Utilities Code Section 463(b) contains the following legislative guidance regarding how the Commission needs to approach hindsight review of very large capital projects:

> This subdivision does not apply where the commission determines that a reasonable person could not have anticipated either the relevance or potential relevance, to an evaluation of costs incurred on the project, of preparing or maintaining the records or the extent of recordkeeping required to adequately evaluate those costs.[89]

Even though this particular statutory provision is not directly applicable to our PSEP proposals for the reasons discussed at length above, it clearly illustrates that the Commission should evaluate past utility actions based on what utilities knew (or should have known) at the time the actions were taken, and not based upon new information, standards, or requirements developed over the following 50-85 years.

Did the Commission put SoCalGas and SDG&E on notice back in 1940 or 1950 or 1960 that perfect recordkeeping was required for pressure test records, that there was no excuses for

[87]Ex. SCG-17 (Rosenfeld) at 29. *See also* Ex. SCG-14 (Montgomery) at 7 ("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.").
[88] *See* TURN Opening Brief at 14 (citing D.94-03-048 (no page reference provided)).
[89] Public Utilities Code Section 463(b).

less than absolute perfection, and that any recordkeeping lapses would subject the utilities to tremendous financial consequences? Should utility executives during the Roosevelt, Eisenhower, or Kennedy Administrations be charged with the knowledge that, 50+ years later, this Commission would establish new pipeline safety standards that potentially put a tremendous premium on the retention of past pressure test documentation? Absolutely not. In fact, with no pressure testing required by the Commission until 1961, and with the adoption of grandfathering for pre-1970 pipelines in 1970, it would have been logical for utility executives, until very recently to assume just the opposite. Mr. Tenley, a former federal pipeline safety regulator with over 20 years of experience, nicely summarizes the situation:

> 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.[90]

[90] Ex. SCG-15 (Tenley) at 7.

Recordkeeping "perfection" is an onerous and unreasonable retroactive requirement. Perfection isn't natural, even for the diligent and well-intentioned,[91] and perfect recordkeeping for pressure tests clearly isn't the industry standard, at least during the time period at issue. Hindsight is always 20-20. But the knowledge we now have regarding the Commission's new pipeline safety standards, and the potential relevance of pre-1970 pressure testing documentation under such new standards, should not be imputed to utilities conducting pressure tests 40 or more years ago. For each of the reasons just discussed, the new retroactive recordkeeping "perfection" standard advocated by DRA and TURN should not be adopted by the Commission.

#### 5. Our Proposed PSEP is a Direct Response to the Commission's New Safety Requirements, not the Result of Past Imprudence

In its Opening Brief, TURN cites the February 24, 2012 Scoping Memo in this proceeding for the proposition that "shareholder responsibility" and "disallowance" proposals present a "reasonableness issue" for the Commission's resolution:

> The only issue of cost allocation applicable to Phase 1 . . . is the first-level determination of whether any portion, and, if so, how much, of the Safety Enhancement costs should be borne by shareholders and not ratepayers. This is a reasonableness issue: whether any portion of the proposed Safety Enhancement is not a true enhancement to pipeline safety but is instead remediation of past neglect or failure by SDG&E or SoCalGas to properly operate and maintain the system or to spend the full allocation of funding included in prior rates.[92]

For the reasons set forth above and in our Opening Brief, the Commission should not consider the question of shareholder penalties based on the current record in this proceeding. As

[91] In fact, if perfect adherence to Commission rules is always required, then the Commission technically shouldn't even consider TURN's Opening Brief since TURN submitted a revised Opening Brief several days late to make up for missing required attachments in the original. SoCalGas and SDG&E are not proposing that the Commission ignore TURN's Opening Brief, or treat it any different than if it had been filed on time. We understand that mistakes happen, and this particular mistake has no practical significance. Rather, we are just pointing out that those demanding absolute recordkeeping perfection over the past hundred years are not perfect themselves, and are not held to a perfection standard.

[92] *Assigned Commissioner's Scoping Memo and Ruling*, February 24, 2012, at 5.

to the more narrow issue presented in the Scoping Memo – i.e., whether PSEP costs represent true enhancements to safety or whether the costs represent remediation of past neglect or failure on the part of SoCalGas and SDG&E – the answer is clear. Our proposed PSEP is a direct response to the Commission's new safety requirements and not remediation of past neglect or failure.

In D.11-06-017 the Commission instituted new safety-related requirements which surpass existing state and federal pipeline regulations, and are a clear departure from the "grandfathering" of pre-1970 vintage pipelines under current federal regulations and previous state regulations. Specifically, regulations in place prior to Commission D.11-06-017 did not require SoCalGas and SDG&E to: (1) hydrotest to modern standards pipelines that were installed prior to 1970; or (2) validate the MAOP of all gas transmission pipelines through traceable, verifiable, and complete records. The Commission's new requirements will require SoCalGas and SDG&E to locate records of pressure testing in accordance with Subpart J standards or conduct such pressure tests or replace the pipeline.

This mandate is a new safety-related initiative by the Commission; it is not the result of any violation by SoCalGas or SDG&E of a Commission decision or order, or any other law or regulation. SoCalGas and SDG&E's proposed PSEP is a direct response to that directive from the Commission. SoCalGas and SDG&E do not have a choice about pressure testing or replacing transmission pipelines that do not meet the Commission's new, more stringent standards.

The PSEP costs requested by SoCalGas and SDG&E are not the result of mismanagement or imprudence. Rather, they are a direct and necessary consequence of the new transmission safety requirements established by the Commission in D.11-06-017. SoCalGas and

SDG&E have been complying with GO 112, and the Commission previously determined that we met all the requirements for "grandfathering" of pre-1970 pipelines under that general order. Specifically, the Commission reviewed and approved SoCalGas' efforts related to MAOP validation and pipeline pressure testing when Part 192 was first implemented, noting that: "there is no evidence that the system is being or will be operated in an unsafe manner . . .."[93] SoCalGas, SDG&E, and related parties identified at that time pipelines that did not have documentation of a pressure test. If the Commission had concerns about lack of pressure tests or lack of pressure test records for these lines, it would have raised those concerns in 1968, not 45 years later.

Moreover, there has been absolutely no evidence presented in this proceeding that SoCalGas and SDG&E have operated their systems unsafely, either before or after the Commission authorized "grandfathering" for our pre-1970 transmission lines. Quite the contrary, as discussed above and in our testimony, the evidence demonstrates that SoCalGas and SDG&E have made safety a top priority and have complied with past and existing laws and regulatory requirements relating to our transmission systems.

Ultimately, the Commission will determine the size and scope of our PSEP. SoCalGas and SDG&E strongly support the Commission's new pipeline safety initiatives. But make no mistake about it, any PSEP costs we will incur will be a direct and proximate result of the new directives, and the Commission's unilateral decision to eliminate "grandfathering" of pre-1970 pipelines. We operated safe transmission systems prior to the issuance of D.11-06-017, and we will operate safe transmission systems in the future, whether the Commission's directives in D.11-06-017 are implemented in full, or whether the Commission adopts some or all of the

[93] D.79502, mimeo., at 6.

alternative approaches to long-seam stability verification that we have proposed as potential cost-saving alternatives.

Yes, we do not have pressure test records for a small percentage of our pre-1970 pipelines. But, as discussed above and in the testimony Messrs. Rosenfeld, Tenley, Montgomery, Morrow, and Schneider, this is a *recordkeeping* issue, not a safety issue. We do not need such records to establish or validate MAOP, and a pressure test record that is 50-85 years old is not a relevant indicator of current safety. Moreover, pressure tests conducted prior to 1970 (and related records) would not satisfy the new "modern standards" articulated by the Commission in D.11-06-017. So the existence (or lack thereof) of pressure tests and related records for pre-1970 pipelines is not resulting in any new or different costs in any event.

Finally, even though the February 24, 2012 Assigned Commissioner's Scoping Memo states that "the first-level determination of whether any portion, and, if so, how much, of the Safety Enhancement costs should be borne by shareholders and not ratepayers" is an issue for Phase 1 of this TCAP, the full Commission took a very different approach when it required pipeline safety plans from the state's natural gas utilities. In D.11-06-017, the Commission required only PG&E to propose sharing of pipeline safety costs between shareholders and ratepayers:

> 7. The Implementation Plan should include a rate proposal with the following:
>     a. For PG&E only, proposed cost allocation between shareholders and customers.[94]

With due respect to the Assigned Commissioner, if the full Commission had wished to hold SoCalGas and SDG&E shareholders responsible for some or all of the costs of implementing D.11-06-017, the Commission would have said so in D.11-06-017. The fact that

[94] D.11-06-017, mimeo., at 29 (Conclusion of Law No. 7).

the Commission did not, and required only PG&E out of the state's natural gas utilities to propose cost allocation between shareholders and customers, is further support for the proposition that our proposed PSEP is a direct response to the Commission's new safety requirements, not past imprudence.

#### 6. The Approach of DRA and other Intervenors is Inconsistent with the Commission's Pipeline Safety Goals

DRA starts out its Opening Brief with the following "dig" at our competence and integrity:

> Either the Sempra utilities' gas transmission system is in a terrible state of disrepair, or the utilities are using the opportunity to pad shareholder returns by proposing capital improvement projects that are well beyond the primary directive of the Commission. Clearly, Sempra's ratepayers should not be forced to pay for the remedial or excessive improvements Sempra proposes.[95]

SoCalGas and SDG&E will decline to engage with DRA on this level. Suffice it to say, we take pipeline safety very seriously, and we hope the Commission and its staffers will as well. Our system is not in a "terrible state of disrepair," and we are not attempting to "pad shareholder returns" with our PSEP proposal. Rather, our PSEP represents a good faith response in a very short time period to the Commission's recent new pipeline safety directives – a response that many of our employees have worked countless hours to prepare.

DRA's condescending attitude towards our good-faith proposal does, however, illustrate what SoCalGas and SDG&E perceive to be a much bigger problem. DRA and the other intervenors appear determined to derail our efforts to implement the Commission's safety directives, either through wholesale cuts to the projects we have proposed, or though complete denial of funding for any PSEP-related work. The following chart compares our Phase 1A PSEP proposal with the Phase 1A funding recommendations of DRA, TURN, SCGC, and SCIP:

[95] DRA Opening Brief at 2.

**Phase 1A (2012-2015) and 2011 Interim**
**Funding Recommendations - Direct Costs O&M and Capital - In Millions of Dollars**

| | SoCalGas/SDG&E Proposed Case[96] | DRA[97] | TURN [98] | SCGC [99] | SCIP [100] |
|---|---|---|---|---|---|
| O& M | 268.00 | 10.12 | 30.00 | 0.00 | 0.00 |
| Capital | 1412.00 | 59.63 | 0.00 | 0.00 | 0.00 |
| **Total Funding Recommendations** | **1680.00** | **69.75** | **30.00** | **0.00** | **0.00** |

| | | | | | |
|---|---|---|---|---|---|
| **Total Disallowances Recommended** | | **-1610.25** | **-274.00** | **-73.30** | **-46.70** |

As can be seen from this comparison, only DRA would provide SoCalGas and SDG&E with any current funding to pursue Phase 1A work, and the funding levels proposed by DRA would pay for only a small fraction of the work proposed by SoCalGas and SDG&E. SoCalGas and SDG&E find this approach to safety-related improvements to be very troubling – particularly because the Phase 1A work identified by SoCalGas and SDG&E generally involves upgrades to older pipelines in highly populated areas.

SoCalGas and SDG&E are also concerned about the safety-related implications of arguments by intervenors that the Commission has not eliminated the "grandfathering" of pre-1970 pipelines, and that if SoCalGas and SDG&E can just find pressure test records satisfying earlier standards or requirements, we would not need to pressure test those particular pre-1970

[96] Ex. SCG -09 (Rivera) at 104-105.
[97] Ex. DRA-05 (Sabino) at 5.
[98] Ex. TURN-01 (Long) at 1-2; TURN-02 (Marcus) at 2 (recommends the Commission limit its approval of the cost and scope of SoCalGas and SDG&E's PSEP to a near-term subset of the utilities' proposed PSEP projects. According to TURN, the Commission should develop a framework that permits a more expedited review of the more fully-developed project proposals, once presented, while still permitting the scrutiny of the selected projects and the associated cost forecasts necessary to determine the reasonableness of the specific proposed projects and their costs.).
[99] Ex SCGC-01 (Yap) at 10, 14 (The Commission should require SoCalGas and SDG&E to file an Expedited Application for each proposed pipeline replacement.).
[100] Ex. SCIP-01 (Beach) at 4.

pipelines to "modern standards" (i.e., 49 CFR Part 192, Subpart J, as it appears in today's Code of Federal Regulations).[101] As explained in our Opening Brief, this position by intervenors flies in the face of the clear language of Ordering Paragraph No. 4 of D.11-06-017.[102] Moreover, intervenors' claims that Ordering Paragraph No. 3 of D.11-06-017 still permits grandfathering of pre-1970 pipelines turns a blind eye to the following unambiguous directive in that very same decision:

> *Historic exemptions must come to an end* with an orderly and cost-conscious implementation plan.[103]

SoCalGas and SDG&E believe that it would be contrary to the interests of safety for the Commission to adopt the "Ordering Paragraph No. 3" proposals of intervenors and permit wholesale "grandfathering" of pre-1970 transmission lines. The logical reading of Ordering Paragraph No. 3 is that it sets for a method for establishing a prioritization method to reach the goal of Ordering Paragraph No. 4. Now that the Commission has established new pipeline safety standards, it should not back away from them -- even if backing away might mean somewhat lower rates, at least in the near term.[104]

Even DRA, the most vocal opponent of our current pipeline safety proposals, admits that testing to modern Subpart J standards would promote safety.[105] And while SoCalGas and SDG&E have put forth proposed alternatives to testing or replacing, these alternative methods, with the exception of non-destructive examination, are yet proven to be an equivalent means to pressure testing or replacing. That is why we propose to use the TFI tool in connection with pressure testing to gather data to determine its equivalency to pressure testing. It is also why we

[101] DRA Opening Brief at 18-19 and 27-28; SCIP Opening Brief at 4-5; TURN Opening Brief at 94-95.
[102] *See* SoCalGas/SDG&E Opening Brief at 39.
[103] D.11-06-017, mimeo., at 18 (emphasis added).
[104] Eventually all pre-1970 pipelines will reach the end of their useful life and need to be replaced. Accordingly, the question is not if such pipelines will ever be brought up to modern standards, but, rather, when.
[105] *See* Tr. at 1612 (DRA/Peck).

have requested that stake holders and Commission staff work together to develop a standard for determining when a pressure reduction may be used as an alternative to pressure testing or replacement. If the Commission wants to achieve its new pipeline safety goals at the lowest possible cost, it should authorize us to move forward with these plans.

### 7. Intervenors' Shareholder Cost Responsibility Proposals would Create Perverse Incentives

SoCalGas and SDG&E will not take actions that would compromise the safety of their transmission systems, and we will always be cognizant of the potential customer impacts from PSEP-related work. As explained by Dr. Montgomery in testimony, however, intervenors' shareholder responsibility proposals would create undeniably perverse incentives that intervenors are simply ignoring.

First, for the pre-1970s pipelines that are at issue in this proceeding intervenors' proposals would create 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 segments as possible and keep them in the system for as long as possible using high levels of future O&M.[106] Accordingly, under the intervenors' proposals the pre-1970 pipeline system is likely to be upgraded in a way that makes it more expensive to operate going forward.[107]

For all other pipeline-related expenditures, the impact of the intervenors' proposals would be markedly different. The disproportionate penalty proposed by the intervenors for missing paperwork (even if no paperwork or underlying pressure test were originally required), would create 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.[108] This would involve redundancy in

[106] Ex. SCG-14 (Montgomery) at 9-10.
[107] Ex. SCG-14 (Montgomery) at 10.
[108] *See* Ex. SCG-14 (Montgomery) at 10.

pipeline construction, testing, maintenance and recordkeeping in excess of a reasonable standard of economic efficiency. By holding SoCalGas and SDG&E retroactively to a new and higher standard, the intervenors' proposals would create an incentive for a more costly system that would be proof against unknown future changes in standards.[109] Dr. Montgomery refers to this behavior as "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.[110] Moreover, the penalties proposed by intervenors could have an effect beyond pipeline-related expenditures and recordkeeping. Imposition of a new standard, and imposition of large penalties for imperfect compliance, years after an activity takes place, would create uncertainty about what standards will be applied by the Commission in the future across the board.[111]

Unlike intervenors, the Commission should not ignore the perverse incentives that would result from intervenor "shareholder responsibility" and "disallowance" proposals.

#### 8. Intervenors' Shareholder Cost Responsibility Proposals would Increase Overall Customer Costs

Intervenor shareholder cost responsibility proposals are all based on the narrow premise that customer rates will be lower if the Commission would just force SoCalGas and SDG&E to pressure test or replace their pre-1970 pipeline systems at no cost to customers. None of them look at the bigger picture – i.e., the potential effect on customer costs of a regulatory taking of unprecedented magnitude. As our expert economist Dr. Montgomery has explained, intervenor proposals would lead to an unambiguous cost increase for SoCalGas and SDG&E customers.[112]

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[109] Ex. SCG-14 (Montgomery) at 10.
[110] Ex. SCG-14 (Montgomery) at 6.
[111] Ex. SCG-14 (Montgomery) at 8.
[112] Ex. SCG-14 (Montgomery) at 16.

According to Dr. Montgomery, the intervenors' proposals amount to an arbitrary and disproportionate penalty, which would adversely affect the willingness of shareholders to invest in future infrastructure programs, ultimately increasing the cost of financing for new investment.[113] Moreover, this appearance of a new risk of regulatory opportunism would not be limited to just our current PSEP. 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.[114] As a result, the intervenors' proposals would create a qualitative change in the regulatory regime, with potentially severe implications for future utility investment decisions in all areas.[115]

As pointed out by Dr. Montgomery, 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. 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.[116] As a result, the borrowing costs for the utilities, and the rates borne by ratepayers, will rise. 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.[117]

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[113] Ex. SCG-14 (Montgomery) at 16.
[114] Ex. SCG-14 (Montgomery) at 16.
[115] Ex. SCG-14 (Montgomery) at 16.
[116] Ex. SCG-14 (Montgomery) at 17.
[117] Ex. SCG-14 (Montgomery) at 18.

Intervenors do not have a rejoinder to Dr. Montgomery's clear and unambiguous explanation of the damage that intervenor "shareholder responsibility" and "disallowance" proposals would inflict on customer rates. Instead, their only focus is on short-term rates, and obtaining as much pipeline safety upgrade work for as free to ratepayers as possible. SoCalGas and SDG&E urge the Commission to look beyond this inaccurate, short-term "zero-sum game" thinking, and consider the bigger overall picture that intervenors choose to ignore.

#### 9. Requiring SoCalGas and SDG&E Shareholders to Pay PSEP Costs Would Violate the Takings Clauses of the U.S. and California Constitutions

As explained in our Opening Brief, requiring SoCalGas and SDG&E shareholders to pay for the cost of implementing the Commission's new pipeline safety standards would violate the takings clause of both the United States and California Constitutions.[118] SoCalGas and SDG&E will refrain from repeating the constitutional and decisional authorities cited in our Opening Brief. But we do wish to briefly point out the unreasonable nature, from a constitutional standpoint, of the "shareholder responsibility" and "disallowance" proposals described in intervenors' Opening Briefs.

SoCalGas and SDG&E are required to comply with the Commission's new pipeline safety standards. We have no choice in the matter. As discussed above, there is an ongoing debate among the parties regarding exactly what the Commission is requiring of us (i.e., is "grandfathering" still allowed for certain pre-1970 pipelines). Ultimately, however, SoCalGas and SDG&E need to bring our pre-1970 pipelines into compliance with the Commission's new standards, and we will do whatever testing and replacement work the Commission requires of us. Intervenor proposals would have SoCalGas and SDG&E do much of this work at no cost to ratepayers.

[118] *See* SoCalGas/SDG&E Opening Brief at 63-64.

For example, if SoCalGas and SDG&E are required to replace pipelines installed in the Eisenhower era (i.e., post-1955), DRA and TURN would require us to build this new asset entirely at shareholder expense, and then dedicate the new pipeline to public use for the next 50-70 years while receiving no return or reimbursement on our expenditures related to this dedicated asset. SoCalGas and SDG&E could not sell or close down the new pipeline as long as it is still deemed to be "necessary or useful" to the public utility service we provide, and perhaps almost a century from now it would still be providing free service to our customers. And when utility executives in year 2060 question the reason for these expensive capital assets in their rate base that earn absolutely no return, is the answer that this treatment is the end result of some horrible accident or terrible financial scandal in years past? "No" the resident utility historian will reply, "We either lost a pressure test document from over 100 years ago relating to a pipeline that was at or near the end of its useful life when the treatment was established back in 2012, or we didn't conduct a pressure test in the 1950s on that same pipeline that we weren't required to conduct anyway."

SoCalGas and SDG&E understand the motivation behind intervenors' "shareholder responsibility" and "disallowance" proposals. Free stuff is nice, particularly in hard economic times. But pressure testing and pipeline replacement are not free for utilities. In order to fulfill our statutory obligation to provide safe and reliable natural gas service to all of our customers, however, 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.[119] Intervenors shareholder responsibility proposals, if adopted by the Commission, would surely violate the regulatory compact, and effectuate an unconstitutional taking of utility assets.

#### 10. The Commission should not take any Action With Respect to Post-1970 Pipelines in this Proceeding

Certain intervenors argue that SoCalGas and SDG&E shareholders should bear the entire cost of pressure testing or replacing post-1970 pipeline segments that lack sufficient documentation of pressure testing.[120] This issue is not ripe. Phase 1 of this proceeding is only about our proposed PSEP, and SoCalGas and SDG&E have made it clear that we are not seeking cost recovery through our PSEP for work relating to post-1970 pipelines.[121] Questions regarding who pays for costs *not* included in the PSEP should be considered by the Commission if and when SoCalGas or SDG&E seek recovery of such costs in rates. A decision with respect to such costs now would be an advisory opinion not based upon record evidence or issues presented to the CPUC for resolution. The Commission does not ordinarily issue advisory opinions.[122] There is no reason to deviate from this well-established tradition for post-1970 pipeline costs that SoCalGas and SDG&E have not included in their PSEP.

SoCalGas and SDG&E do wish to briefly note, however, that it would not be reasonable to require them to dedicate new pipelines or pipeline segments to public use for the next 50-70 years without return or compensation, whether the new capital asset is a replacement for a pre-1970 pipeline or a post-1970 pipeline. And as with pre-1970 pipelines, if there is any

[119] Ex. SCG-13 (Morrow) at 5.
[120] *See* DRA Opening Brief at 3-4; TURN Opening Brief at 30-31; SCGC Opening Brief at 17-18.
[121] Ex. SCG-13 (Morrow) at 11.
[122] *See, e.g.*, D.12-01-032, mimeo., at 150-51 ("Like the courts, we have a long-standing policy against issuing advisory opinions"); D.00-06-002, mimeo., at 1 ("We only issue advisory opinions in extraordinary circumstances").

examination of whether there should be a recordkeeping penalty associated with post-1970 pipelines, the examination should be done in a segment-by-segment basis, in a context in which all relevant issues can be considered.

## IV. REASONABLENESS OF SOCALGAS AND SDG&E'S PHASE 1A RECOMMENDATIONS

### A. Decision-Making Process

Please see our Opening Brief on this topic.

### B. Review of Decisions (Expedited Application Docket, Advisory Panel, etc.)

#### 1. Engineering Advisory Board

TURN attempts to diminish the potential significance of the Engineering Advisory Board (EAB) proposed by SoCalGas and SDG&E by asserting that "[t]he Board proposal is the product of a fifteen-minute conversation among utility employees pondering how to respond to the proposals contained in intervenor testimony, a conversation that produced no notes or other documentation."[123] This characterization is not accurate. While the initial EAB discussion that Mr. Phillips was involved in may have taken approximately 15 minutes, our entire EAB proposal was not developed at that time. Rather, our proposed EAB is actually the product of a fifteen-minute "initial discussion" and multiple "follow-up discussions."[124]

TURN and DRA criticize SoCalGas and SDG&E for not lining up potential EAB participants prior to making our proposal, with DRA pointing out that "there is no assurance that any of the putative invitees are available or interested in participating in this Board."[125] SoCalGas and SDG&E believed that CPSD and the Commission's Energy Division would view participation on the proposed board favorably, and be interested in participating "as a way to

[123] TURN Opening Brief at 43-44.
[124] Tr. at 1114 (SoCalGas/SDG&E/Phillips).
[125] DRA Opening Brief at 53. *See also* TURN Opening Brief at 44.

provide some visibility into the decision-making process that Sempra would go through."[126] However, to the extent CPSD and Energy Division do not believe their inclusion worthwhile; we would support having an advisory board comprised of independent outside experts -- so long as the board members have sufficient expertise in pipeline engineering and operations.[127]

TURN and DRA argue that the EAB is of no value because it would not have decision-making authority."[128] Again, SoCalGas and SDG&E do not agree. SoCalGas and SDG&E envision the EAB to be a "peer review" of our engineering and operations decisions.[129] Simply because the EAB would not have ultimate responsibility for engineering and operational decisions would not render the EAB insignificant. SoCalGas and SDG&E must maintain final authority for all decisions relating to the design, construction, and operation of our transmission systems because we are ultimately responsible for such activities. But that does not mean we would give short shrift to the opinions of the Energy Division, CPSD, or outside experts empanelled to provide us advice with respect to such decisions. Our EAB proposal is intended to provide SoCalGas and SDG&E with Commission (or outside expert) input regarding our proposed PSEP-related decisions, and we would most certainly take advantage of such input. As Mr. Phillips explained during hearings:

> Q What would happen if there's a tie?
>
> A I guess it depends on what the issue is. Sometimes the issues are small. And people agree to disagree and move on. And sometimes they're large. And if they're large, then I assume there's some way to raise that up, if it's -- if it's a strong concern by board members.
>
> Q What if the CPUC members vote two in disagreement?

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[126] Tr. at 1093 (SoCalGas/SDG&E/Phillips).
[127] SoCalGas/SDG&E Opening Brief at 102; Tr. at 1245 (SoCalGas/SDG&E/Phillips).
[128] TURN Opening Brief at 44; DRA Opening Brief at 53.
[129] Tr. at 1115 (SoCalGas/SDG&E/Phillips).

> A As I said, it depends on if it's a small item or a large item. I assume -- we've assumed that if the CPSD or energy delivery had a strong disagreement with something that Sempra thought was a reasonable way to move forward, that there would be some mechanism for them to raise it at the Commission.
>
> …
>
> Q So you used the term "raise it up" earlier. To whom would it be raised if there's a disagreement?
>
> A Your question was about what would happen if there was a tie, and my answer was I presume -- I don't know what the official way for it to happen, but I presume if somebody from the energy delivery or CPSD felt strongly that Sempra was not doing the right thing, that there must be some mechanism for them to go up to somewhere in the Commission and raise that concern.
>
> …
>
> Q So could the utility just ignore the input that the board gives it?
>
> A I'll say at our peril. [130]

Finally, TURN argues the EAB would constitute an impermissible delegation of Commission authority to staff: "the determination of whether the utilities' PSEP ongoing activities are reasonable is part of the Commission's authority and responsibility under the Public Utilities Code, particularly Section 451 and its directive for 'just and reasonable' rates. The Commission cannot delegate that authority, even to staff."[131] As just discussed, however, the EAB would not have decision-making authority; there would be no potential delegation of authority to Commission staff (or outside experts) if SoCalGas and SDG&E ultimately remain responsible for PSEP-related decisions, as we have proposed. Moreover, in a recent decision concerning an application for a CPCN to construct and operate a coastal water project, the

[130] Tr. at 1096-1098 (SoCalGas/SDG&E/Phillips).
[131] TURN Opening Brief at 45.

Commission addressed concerns it had unlawfully delegated its Section 451 duty to ensure just and reasonable rates:

> What we did grant to the Public Agencies was authority to move forward with their portion of the project and incur prudent expenditures consistent with the Decision. We routinely grant similar authority to regulated utilities in order to proceed with an approved capital project…Granting authority to move forward with the project, and recognizing that actual costs may be different than the authorized amount is not synonymous with an unlawful delegation of authority.[132]

The same logic applies to our PSEP proposal. The Commission can and should grant us authority to move forward with this program, knowing that actual costs may ultimately be different from amounts originally authorized. Neither such approval, nor authorization to establish a new EAB to assist the utilities with their ongoing PSEP-related decision-making process, would constitute a violation of Section 451 (or any other provision of the Public Utilities Code).

### 2. SCGC's Proposed EAD Process

SCGC has proposed an Expedited Application Docket (EAD) process for reviewing on a case-by-case basis SoCalGas and SDG&E's decisions to replace rather than pressure test pipeline segments greater than 1,000 feet in length.[133] Pursuant to this proposed process, SoCalGas and SDG&E would serve applications for expedited review on all parties, who would have either 30 or 45 days to respond; responses to protests would be due within 10 days thereafter; the assigned ALJ would lead a technical workshop within either 42-48 days or 57-63

[132] D.11-04-035, mimeo., at 5.
[133] SCGC Opening Brief at 24-36.

days of the application's filing date, and the Commission would endeavor to issue a decision within either 75 or 90 days of the filing.[134]

SoCalGas and SDG&E believe that the PSEP review and oversight process we have presented is reasonable and appropriate. The level of review and oversight provided by our various process-related proposals (*e.g.*, the EAB) would be substantially greater than review and oversight under traditional test-year ratemaking, and no additional Commission review of our PSEP-related decisions should be necessary.

If the Commission does not agree, however, the answer is *not* the *ex post* reasonableness review proposed by DRA.[135] For all the reasons discussed above and in our Opening Brief, an *ex post* review of test or replace decisions, decisions to accelerate mileage, and decisions regarding expenditures to manage customer impacts would be unworkable. If the Commission determines that there is a need for additional review and oversight above what we have proposed – and again, we do not believe that such additional review and oversight will be necessary – SoCalGas would not be opposed to the EAD process proposed by SCGC for replacement projects,[136] and supported by both TURN[137] and UWUA,[138] as long as the process could be streamline and truly expedited so as to not delay further the implementation of PSEP.

Our primary concern with SCGC's proposed EAD process is time. If such a process is adopted, it truly needs to be a finite 75-day or 90-day process, and it cannot be allowed to devolve into a longer process because intervenors or CPUC staff become overwhelmed by the amount of information provided by the utilities or the number of EAD proceedings going on at

[134] SCGC Opening Brief at 29-30. SCGC's testimony and Opening Brief are not clear on which dates SCGC is actually proposing. SoCalGas and SDG&E would obviously like the more aggressive set of deadlines.
[135] *See* DRA Opening Brief at 53.
[136] SCGC Opening Brief at 28-36.
[137] TURN Opening Brief at 9-12.
[138] UWUA Opening Brief at 2.

any one time.[139] During hearings and in testimony, SoCalGas and SDG&E discussed the multitude of engineering and operational factors the EAB would need to consider.[140] Since the data submitted as part of an EAD application would be "pretty close to the same" as the data submitted to the EAB,[141] each EAD would involve a large amount of data and decisions, and there could be close to 100 replacement projects that would need to be run through the EAD process.[142] Most PSEP projects will likely involve confidential information, including proprietary models, sensitive system information, and confidential customer information. Any EAD process adopted by the Commission would need to protect the confidentiality of this data.

SoCalGas and SDG&E remain skeptical that an EAD process can be implemented in a manner that would allow detailed consideration of so many projects within a 75-day or 90-day timeframe. That said, an EAD process may potentially be workable if it is designed correctly; *ex post* reasonableness review of test-versus-replace and other important PSEP decisions is not. If the Commission does decide to establish an EAD process for our PSEP projects, SoCalGas and SDG&E will hold up our end of the bargain and work to ensure that all necessary project-related information is presented in the format designated by the Commission (we agree with SCGC's proposal for an agreed-upon master data request format)[143] within the timeframes established by the Commission.[144] We also support a finite 75-day or 90-day timeframe for the entire

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[139] *See* Tr. at 1191 (SoCalGas/SDG&E/Phillips).
[140] *See* Ex. SCG-20 (Phillips) at 9-11; Tr. at 1079-1091 and 1147-1154 (SoCalGas/SDG&E/Phillips).
[141] Tr. at 1192 (SoCalGas/SDG&E/Phillips).
[142] Tr. at 1191 (SoCalGas/SDG&E/Phillips).
[143] SCGC proposes that Energy Division conduct a technical workshop to develop a master data request for the expedited procedure for review of proposed pipeline replacements. Ex. SCGC-01 (Yap) at 12.
[144] *See Order of the Georgia Public Utilities Commission Adopting Stipulation*, filed October 13, 2009, Docket Nos. 8516 & 29950 (in our Opening Brief at 100, SoCalGas and SDG&E requested the Commission take official notice of this decision). In this decision, the State of Georgia implemented a similar process for Atlanta Gas Light Company (AGLC). Under the program, AGCL submits its preliminary engineering analysis and supporting documents, a public hearing is held, and not more than 120 days after the original filing the Georgia Commission must issue a decision approving or rejecting the plan. Any approved plan shall meet relevant engineering and operational standards, and provide for a rate designed to cover the costs of the plan. If an approved plan differs materially from the plan proposed by AGLC, the utility may accept or decline the revised plan. One of the reasons

application-to-decision process, as was used in the previous contractual EAD process implemented by the Commission in the 1990s for the review of discounted anti-bypass contracts.[145] But the finite timeframe needs to be a mandatory time limit for EAD participants, not an "aspirational" goal that can be changed to accommodate workload issues and schedule constraints. In addition, in order to prevent the EAD process from derailing PSEP and implementation of the Commission's new pipeline safety standards, EAD application dockets should automatically be deemed approved if the Commission has not acted on them within the specified 75 or 90 days.

Adoption of an EAD process for *all* Phase 1A pipeline replacement projects could lead to substantial program delays as work that would otherwise take place is put on hold while SoCalGas and SDG&E go through the process of preparing applications, gearing up for data requests, submitting applications, and participating in individual EAD proceedings. If the Commission is supportive of an EAD process – and again, SoCalGas and SDG&E believe that such a process is not really needed – we propose that the replacement projects already approved by the Commission for inclusion in the PSEP Memorandum Account[146] be authorized to move forward outside the PSEP process in the manner we have proposed in our application. SoCalGas and SDG&E further request that the Commission make it clear that pipeline testing, valves, and all other aspects of our PSEP other than pipeline replacements are not included in the EAD process, and that such work is authorized to proceed as we have proposed.

SCGC's EAD proposal includes two interrelated items which require additional discussion. First, SCGC proposes that estimates submitted to the EAD be a minimum of a Class

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that AGCL may decline to accept a revised plan is if the plan fails to recover the actual revenue requirements of the projects covered by the plan.

[145] *See* SCGC Opening Brief at 30 (citing D.92-11-052).

[146] D.12-04-021, mimeo., at 7.

3 estimate.[147] SoCalGas and SDG&E oppose this proposed requirement because EAD proceedings could easily devolve into endless warfare over whether the utilities had actually presented a Class 3 estimate or not. As discussions during the Phase 1 hearings illustrate, estimate classification is a technical and somewhat obtuse field, and the question of appropriate classification still involves a good deal of judgment.[148] If an EAD process is established, SoCalGas and SDG&E understand that their project estimates will need to withstand critical scrutiny or they will not be approved. No specific AACE class estimate requirement is needed. The Commission will either be comfortable with our estimates (and supporting documentation), or it will not be. A "Class 3" label will not change this fact, and we do not need to waste precious time arguing about AACE classifications.

Second, SCGC proposes establishment of a cost cap equal to the approved replacement project estimate.[149] Costs that exceed this cap would not be permitted to be recovered in rates absent a reasonableness review.[150] SoCalGas and SDG&E understand the purpose for such a cap, and we would not object to the establishment of an initial project cap based on the project estimate authorized by the Commission in the EAD proceeding. However, if there is to be a cap, there would need to be a reasonable contingency built into the estimate,[151] and there would also need to be a process for dealing with unanticipated events or project-related problems outside of our control that cannot be factored into the contingency process. For example, a force majeure

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[147] SCGC Opening Brief at 30.
[148] *See, e.g.*, Tr. at 581-87, 617-618, 862-866 (SoCalGas/SDG&E/Buczkowski).
[149] SCGC Opening Brief at 31.
[150] SCGC Opening Brief at 31.
[151] An AACE Class 3 estimate is typically used for "budget authorization or control." Ex. DRA-19 (AACE RP 17R-97) at p. 2; *see also* Ex. SCGC-01 (Yap) at 26. According to the DOE Directive on Contingency, a "budget" estimate should include a contingency allowance of 15 to 25 percent. Ex. DRA-20 (DOE Office of Management, Directive G 430.1 Chapter 11 – Contingency) at 11-3. *See also* Tr. 601-02 (SoCalGas/SDG&E/Buczkowski) ("AACE does have a document 16R-90 that has a range of contingencies. And they also have a statement that says for budget type estimate project contingency would range from 15 to 30 percent.").

event such as an earthquake should not trigger an *ex post* reasonableness review. As Mr. Buczkowski explained in his rebuttal testimony:

> 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.[152]

### C. Base Case

In general, SoCalGas and SDG&E will rely upon their Opening Brief presentation regarding the need for, and reasonableness of, each of the components of their PSEP base case. SoCalGas and SDG&E do, however, wish to briefly respond to TURN's assertions regarding record review costs included within the interim safety enhancement measures, and certain inaccurate contentions by DRA and TURN regarding our valve enhancement plan.

#### 1. Record Review Costs Were Appropriately Included within the Interim Safety Enhancement Costs and Estimates

TURN seeks to deny recovery of costs incurred by SoCalGas and SDG&E reviewing pipeline records in order to validate MAOP and classify pipeline segments for PSEP purposes. TURN alleges that SoCalGas and SDG&E's inclusion of these costs within interim safety measures was "so confusing as to appear deceptive" and that "nothing in the utilities' testimony" made it clear that costs within the "Interim Safety Enhancement Measures" category were costs associated with records review.[153] This is incorrect. TURN's allegations should be rejected as nothing more than a ploy to reject cost recovery of reasonable expenses incurred to implement a new request by the Commission.

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[152] Ex. SCG-21 (Buczkowski) at 11.
[153] TURN Opening Brief, at 53.

In Resolution L-410 the Commission required SoCalGas and SDG&E to "pay particular attention to NTSB recommendations to PG&E entitled P-10-2, P-10-3, and P10-4."[154] In response, SoCalGas and SDG&E reviewed records to categorize pipeline segments and initiate interim safety measures. SoCalGas and SDG&E have been clear regarding their proposed inclusion of these record review costs within interim safety measures. In fact, the very first request in our Direct Testimony Executive Summary requests:

> Authorize the recovery of costs incurred to date, and to be incurred up to the time the Commission issues a decision approving our proposed plan, for the review of transmission pipeline records and for implementation of our interim safety enhancement measures. To date, we have incurred costs of approximately $3 million and forecast that we will spend a total of about $7 million by year-end.[155]

The Commission has recognized that SoCalGas and SDG&E consider these two elements together:

> Attachment B to the January 13, 2012, filing showed the costs for records review as required by Commission Resolution L-410 and the interim safety measures. Of the $11.8 million total for SoCalGas, the vast majority, $10.2 million, is for records review. For SDG&E, all but a trivial amount of the $1.3 million is for records review.[156]

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[154] NTSB Recommendations P-10-2 and P-10-3 required SoCalGas and SDG&E to:

> Aggressively and diligently search for all as-built drawings, alignment sheets, and specifications, and all design, construction, inspection, testing, maintenance, and other related records, including those records in locations controlled by personnel or firms other than Pacific Gas and Electric Company, 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. These records should be traceable, verifiable, and complete. (P-10-2) (Urgent).
>
> …
>
> Use the traceable, verifiable, and complete records located by implementation of Safety Recommendation P-10-2 (Urgent) to determine the valid maximum allowable operating pressure, based on the weakest section of the pipeline or component to ensure safe operation, of 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. (P-10-3) (Urgent).

[155] Ex. SCG-01 (Morrow) at 5-6.

[156] D.12-04-021, mimeo., at 4.

Therefore, there was nothing deceptive or misleading about SoCalGas and SDG&E's inclusion of these costs in our PSEP.

### 2. Our Valve Enhancement Plan Should be Approved as Proposed

DRA and TURN's discussion of SoCalGas and SDG&E's Valve Enhancement Plan presents a number of statements and recommendations which lack support or demonstrate a misunderstanding of SoCalGas and SDG&E's proposal.

First, DRA states: "more disturbing than the flaws in Sempra's cost estimates are the seeming inconsistencies between its claims in other parts of its testimony about the safety of its system, and the arguments it makes in its Valve Enhancement testimony about the immediate need for valve upgrades. For example, after reviewing DRA's proposal, Sempra says that DRA's recommended Valve Enhancement Program would *decrease* public safety."[157] DRA concludes that SoCalGas and SDG&E's proposal indicates a "serious safety flaw in the current Sempra system."[158] These statements are wrong and not supported by the record.

> Q Okay. If you go to page 2 in your rebuttal, at line 14 you say that:
>
> DRA, TURN, UWUA set forth proposals which are unresponsive to Commission directives, trade minimal and speculative cost savings for decreased public safety.
>
> Is it your opinion that the shutoff valve replacement proposal by DRA will increase or decrease public safety compared to today?
>
> A What we were trying to say in that line 15 is that by not having the full implement -- or all elements to the valve enhancement plan, what you would end up with is a plan that would not work, would not increase safety beyond where it is at this point in time.
>
> Q So it is your opinion that the valve, shutoff valve replacement proposal by DRA would decrease public safety compared to today?

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[157] DRA Opening Brief at 61.
[158] DRA Opening Brief at 62.

A No. Our reference was to as it refers to the valve plan itself.

Q Do you have an opinion on whether adoption of DRA's valve replacement proposal would increase or decrease public safety compared to today?

A In some respect trying to implement DRA's valve plan would decrease public safety in that you would have a plan in place that wouldn't do the things that it promised to do.

Q So your answer was it would decrease --

A Yes.

Q -- Public safety?[159]

Mr. Rivera first explains that DRA's proposal would not enhance safety beyond where it is today. Mr. Rivera then states that DRA's proposal would not decrease safety, but would not enhance safety either and explains that his concern with DRA's plan is that it would instill a false sense of security regarding the system being *safer* without actually being safer. We are confident the system is currently safe, but were asked by the Commission to develop a valve enhancement plan to further enhance system safety. Because the system's safety may be enhanced is not indicative of a flawed or unsafe system.

SoCalGas and SDG&E operate a safe system. In the event of a rupture, SoCalGas and SDG&E are able to isolate the rupture using a combination of manual valves, ASVs, and RCVs. In order to enhance safety, SoCalGas and SDG&E's Valve Enhancement Plan proposes utilizing ASVs and RCVs at 8-mile spacing so as to achieve quicker, automated or remote rupture isolation.[160] DRA argues that the same level of rupture isolation may be achieved at a lower cost by installing ASVs at 16-mile spacing. This is incorrect. In a system of complex, interconnected pipelines, an effective valve enhancement plan requires installation of valves on connecting

[159] Tr. at 1267-68 (SoCalGas/SDG&E/Rivera).
[160] SoCalGas and SDG&E's Opening Brief at 117-123.

pipelines to achieve full isolation.[161] Simply placing valves at 16-mile intervals without consideration of connecting pipelines and backflow, will, in many instances, not provide for complete isolation of a rupture.[162] Thus, to enhance safety as requested by the Commission, the 16-mile spacing proposed by DRA would still require additional valves on connecting lines. Failure to install improved valves at those locations would not decrease safety (as manual valves would remain), but it would not increase safety either. Ultimately, if automation and safety enhancement is the objective, an 8-mile or 16-mile valve enhancement plan will necessarily end up looking similar in terms of valve count and costs as full isolation must be the end result.[163]

Finally, TURN recommends the Commission "reject the utilities' funding request for converting ASVs to RCVs and direct the utilities to work with the CSPD to analyze the proper spacing and installation of automatic shutoff valves on the Sempra Utilities' system."[164] First, it should be clarified that SoCalGas and SDG&E are not requesting permission to convert ASVs to RCVs. Rather, we are proposing the addition of RCV capabilities to existing ASVs; allowing for dual capability.[165] In addition, the $21 million funding request also includes related system response and operational flexibility upgrades necessary when hundreds of ASVs and RCVs are installed in areas of complex piping.[166] Meaning, the $21 million is not just to be incurred to modify ASVs to include RCV capability, but also to provide for real-time SCADA monitoring of pressure and valve status at each location.[167] It bears repeating that the importance of these companion enhancement elements was recognized by CPSD in its Technical Report on SoCalGas and SDG&E's PSEP:

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[161] Ex. SCG-23 (Rivera) at 7.
[162] Ex. SCG-23 (Rivera) at 7.
[163] Ex. SCG-23 (Rivera) at 7.
[164] TURN Opening Brief at 58.
[165] Ex. SCG-05 (Rivera) at 81 (noting upgrading existing ASVs to include RCV functionality); *see also* Ex. SCG-32 (Workpapers) at WP-IX-2-75 and WP-IX-2-76.
[166] Ex. SCG-32 (Workpapers) at WP-IX-2-75 and WP-IX-2-76.
[167] Ex. SCG-32 (Workpapers) at WP-IX-2-75 and WP-IX-2-76.

> 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 they allow for pin-pointing failure locations and will assist in first response efforts to any failure events.[168]

For all other base case issues, please see our Opening Brief.

### D. Proposed Case

SoCalGas and SDG&E will for the most part rely upon their Opening Brief presentation regarding their PSEP proposed case.

SoCalGas and SDG&E do, however, wish to briefly respond to DRA's assertions regarding certain pipeline projects included in our PSEP, and DRA's proposed exclusion of EAMS from PSEP.

#### 1. DRA's Arguments Regarding the Proposed Extension of Line 6914 and Related Abandonment of Line 41-6000-2 are not Reasonable

DRA argues that our proposal to abandon Line 41-6000-2 and extend Line 6914 is beyond the scope of D.11-06-017, and therefore these projects should be excluded from PSEP.[169] According to DRA, even though our testimony explains that we are not including existing Line 6914 (installed in 2009) in PSEP, our workpapers "show something else."[170] DRA asserts that we are not proposing to replace the segment that lacks reliable records (Line 41-6000-2), but instead simply adding new segments to a different pipeline (Line 6914).[171] DRA's position on this topic is neither accurate nor reasonable.

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[168] *Technical Report of the Consumer Protection and Safety Division Regarding the SoCalGas and SDG&E Pipeline Safety Enhancement Plan* at 16, filed January 27, 2012 in R.11-02-019 and entered into the record of A.11-11-002 by *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* on April 17, 2012.
[169] DRA Opening Brief at 40-42.
[170] DRA Opening Brief at 41.
[171] DRA Opening Brief at 41-42.

The extension of Line 6914 to facilitate the abandonment of Line 41-6000-2 referenced in workpapers WP-IX-1-A89 and WP-IX-1-B170 is *not* the existing segment of Line 6914 that was installed in 2009. As Mr. Bisi explained during hearings:

> Q As we left it, I think we were talking about Line 6000-2. And just for clarification, I'm trying to understand your workpapers, and what was in the two different pages that I've flagged.
>
> A Okay.
>
> Q So in looking at WP-IX-1-A89 and WP-IX-1-B170, they appear to be the same project. That's correct -- is that correct?
>
> A They are the same project, different parts of the same project.
>
> Q All right. Different parts. Can you explain the different parts?
>
> A Sure. WP-IX-1-A89 concerns the capital cost of extending Line 6914 to allow for the abandonment of 6000-2. And WP-IX-1-B170 concerns the capital cost to connect up the remaining parts of the distribution system with the 6914 extension.[172]

Our plan for Line 41-6000-2 does in fact conform with the Commission's directive in D.11-06-017 to pressure test or replace all pipelines that lack sufficient records. Line 41-6000-2 will be replaced by the extension of Line 6914.[173] The new portion of Line 6914 will not be in exactly the same physical location as Line 41-6000-2. But the *function* of Line 41-6000-2 will nonetheless be fulfilled by the extension of Line 6914:

> Q So then on page A90, you discuss the abandonment of -- of the 36 miles and the replacement of 14 new miles of Line 6000-2. Is this new line actually a replacement of Line 6914?
>
> A No, it's an extension of Line 6914.
>
> Q So it's -- but it's not a replacement of Line 6000-2 because it's in a different location and has a different diameter pipe?

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[172] Tr. at 1428 (SoCalGas/SDG&E/Bisi).
[173] Line 41-6000-2 needs to be replaced rather than pressure tested because it cannot be removed from service. Tr. at 1385 (SoCalGas/SDG&E/Bisi).

A It will be -- it will replace the function of Line 6000-2.

Q So replace the function?

A Correct.

Q Because a replacement is – assumed it's the same place?

A An in kind replacement didn't seem to make sense.[174]

SoCalGas will be able to leverage existing pipeline assets to replace the function of Line 41-6000-2 at a much lower cost than simply replacing the pipeline in-kind, and improve the system capacity as well. As Mr. Bisi explained:

Q And the total is roughly $76 million for the two projects?

A Yes.

Q And do you have the cost of what the alternative would have been to actually replace Line 6002 -- dash 2?

A My -- the cost estimate to replace existing Line 6000-2 in kind was $91 million.

Q And the cost estimate for the new construction of those two sections under the workpapers, is that the totality of the new costs?

A Yes.

Q And does that include everything that would be required to build those lines from rights-of-way acquisition to permitting to environmental review?

A I believe so.[175]

DRA is certainly aware of this testimony by Mr. Bisi (the questions were from DRA's attorney). Yet DRA is *still* taking the position that our proposal to abandon Line 41-6000-2 and extend Line 6914 is beyond the scope of D.11-06-017 – apparently just because it would not be a one-for-one replacement of Line 41-6000-2 with another pipeline of exactly the same diameter

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[174] Tr. at 1392 (SoCalGas/SDG&E/Bisi).
[175] Tr. at 1428-29 (SoCalGas/SDG&E/Bisi).

located in exactly the same spot. This sort of "form over substance" approach to implementing the Commission's pipeline safety directives does not serve anyone well. In effect, DRA is saying just "pave the cow path," even though more cost-effective and efficient routes and approaches are available. SoCalGas and SDG&E have a responsibility to our customers to pursue safety-related improvements in a cost-effective manner. We should not be required to replace a pipeline in-kind when another approach will save significant costs and provide capacity benefits to boot. The Commission should disregard DRA's out-of-touch approach to safety improvements, and authorize SoCalGas and SDG&E to move forward with our proposal to abandon Line 41-6000-2 and extend Line 6914.

### 2. Line 38-959 and Line 38-593 should be Included in PSEP

DRA argues that Line 38-959 and Line 38-593 should be excluded from PSEP because SoCalGas is proposing to increase the capacity of these two pipelines when it replaces the lines as part of its PSEP.[176] According to DRA:

> Sempra has not performed or presented any cost benefit analyses or justification as to why the capacity of these lines needs to increase. Sempra's proposal to replace pipelines should be rejected.[177]

As with DRA's assertions regarding Line 41-6000-2 and Line 6914, DRA's position with respect to Line 38-959 and Line 38-593 is misguided.

First, as explained by Mr. Bisi in his written rebuttal, these two pipelines need to be replaced in order to meet the Commission's new pipeline safety criteria:

> 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

[176] DRA Opening Brief at 42-43.
[177] DRA Opening Brief at 43.

> with manageable customer impact, and are not piggable. Per the SoCalGas and SDG&E PSEP Decision Tree, both pipelines should be abandoned and replaced.[178]

The only thing that makes these lines different from other PSEP projects is our proposal to up-size the lines when we do the necessary replacements. It is not reasonable for DRA to argue to exclude these lines from PSEP because of this proposed up-sizing. We need to replace these lines in order to meet the Commission's D.11-06-017 criteria, whether we up-size the lines or not. Instead, the real question for the Commission to decide is whether SoCalGas should be required to replace Line 38-959 and Line 38-593 with exactly the same diameter pipe that is currently in the ground, or whether SoCalGas may use this opportunity to cost effectively make needed increases in line pressure and line capacity.

SoCalGas has not done a formal cost/benefit analysis of these two capacity increases, but no such analysis is necessary. The capacity of both of these lines needs to be increased in the near future in order to meet customer needs. As explained by Mr. Bisi:

> 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.[179] 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.[180]

DRA's apparent position that every PSEP pipeline replacement must be an exact like-kind replacement flies in the face of logic and common sense. Would a homeowner who needs a

[178] Ex. SCG-22 (Bisi) at 4.
[179] Costs presented in the PSEP are incremental to those in SoCalGas' and SDG&E's GRCs, and, as such, neither SL 38-959 nor SL 38-539 were included in the GRCs for replacement. Ex. SCG-22 (Bisi) at 4.
[180] Ex. SCG-22 (Bisi) at 4.

new French drain or sewer line replace their existing line with the same diameter pipe when they know they will need a larger capacity line within a few years? Of course not. Likewise, does it make sense for a utility to install new (and expensive) natural gas transmission pipeline with an estimated potential service life of over 50 years, just to rip out the new line and replace it in a few years with larger line in order to meet customer demand already forecasted when the smaller line was installed? Of course not. Any short-term savings from initially installing the smaller diameter pipeline will obviously be outweighed by the wasteful cost of having to replace the same pipe twice in short succession.

The Commission should disregard DRA's illogical and short-sighted recommendations with respect to Line 38-959 and Line 38-593, and authorize SoCalGas to continue with these projects just as we have proposed them.

### 3. EAMS should be Included in PSEP

TURN argues that EAMS is intended to remedy past deficiencies and alleges "at least some degree the EAMS proposal is targeted at remedying a current deficient practice."[181] Similarly, DRA argues that "Sempra has not demonstrated that the eleven existing databases and applications currently in use are inadequate for the management of data and records for purposes of meeting the requirements of D.11-06-017."[182] EAMS is not intended to remedy past deficiencies or replace existing systems.[183] Rather, EAMS will serve as a central repository or program to "integrate electronic access to historical data, analysis results and reports based upon source data from many textual and geospatial files and databases"[184] and allow for enhanced

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[181] TURN Opening Brief at 69.
[182] DRA Opening Brief at 76.
[183] Ex. SCG-23 (Rivera) at 23-24.
[184] Ex. SCG-23 (Rivera) at 23.

"pipeline data analytics to support continuous improvement of SoCalGas and SDG&E's pipeline integrity and safety programs."[185]

Next, TURN argues that "[t]he Sempra Utilities expressly did not raise any objection to the TURN recommendations regarding specific direction the Commission should adopt regarding EAMS."[186] To the extent this statement is in reference to Mr. Marcus's recommendation that the Commission approve "seed money" for the EAMS Blueprint, SoCalGas and SDG&E do not disagree.[187] SoCalGas and SDG&E are requesting funding only to identify PSEP EAMS requirements and develop a blueprint for a proposed solution – not final approval.[188] In addition, SoCalGas and SDG&E plan to consider Mr. Marcus's suggestions that SoCalGas and SDG&E: (1) "investigate and, where practicable, pursue EAMS packages that are "off the shelf" and have some minimum amount of interchangeability with other data management tools;"[189] and (2) "pursue EAMS packages that have longer asset lives than the typical five-year asset life of a software program."[190]

Finally, DRA accuses SoCalGas and SDG&E of "seizing the opportunity of this Commission's concern for the safety of public utility patrons, employees and the public to inflate its rate base, and increase its earnings all at the expense of its ratepayers."[191] This is incorrect. SoCalGas and SDG&E were asked to develop an unprecedented plan to pressure test all of our in-service natural gas transmission pipeline in accordance with modern standards. This undertaking will require years of work and result in the creation of an incredible amount of data. EAMS is designed to be a program which will serve as a central repository for this data, enabling

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[185] Ex. SCG-07 (Rivera) at 92.
[186] TURN Opening Brief at 72.
[187] Ex. TURN-02 (Marcus) at 28.
[188] Ex. SCG-23 (Rivera) at 22.
[189] Ex. TURN-02 (Marcus) at 28.
[190] Ex. TURN-02 (Marcus) at 29.
[191] DRA Opening Brief at 77.

SoCalGas and SDG&E to better access, analyze, and use that data to enhance program efficiencies. In this proceeding DRA has argued that any pipeline which fails to have perfect records from 1935 onward should result in significant shareholder penalties,[192] but also argues that a program to compile, store, and analyze similar records going forward is outside the scope and an attempt to inflate rate base.[193] These arguments demonstrate the problem with DRA's position. With one hand DRA would require perfect compliance with even voluntary standards, but with the other, would refuse the utilities incurring any costs beyond the bare minimum.

For all other proposed case issues, please see our Opening Brief.

## V. REASONABLENESS OF COST ESTIMATES

### A. Pipeline Replacement and Testing Estimates

Section V of SoCalGas and SDG&E's Opening Brief explains why SoCalGas and SDG&E's cost estimates are sufficient to set rates on a forecast basis and address many of the issues related to the reasonableness of our cost estimates and contingencies. Intervenors, however, do put forward some contentions which merit individual attention.

#### 1. Intervenors Mischaracterize the SPEC Services Data

Intervenors challenge the qualifications of SPEC Services and the adequacy of the estimates they developed. TURN states: "[t]he cost estimates included in the Sempra Utilities' PSEP request for pipe replacement or pressure testing were prepared entirely by SPEC Services, an outside contractor, and reflect costs and other information from SPEC databases and previous SPEC projects." In addition, DRA challenges the qualifications, competence, and motivations of SPEC Services, stating:

> Sempra offered no verifiable evidence of SPEC's expertise, particularly with regard to risk management and analysis. The fact

[192] DRA Opening Brief at 21-22.
[193] DRA Opening Brief at 77.

> that SPEC failed to provide a "high quality" baseline estimate or any discussion or quantification of risks suggest a lack of expertise in risk management and analysis. Sempra also failed to mitigate the potential bias of one consultant, who might hope to perform the Plan work at an inflated profit, by not seeking input from other experts.[194]

Intervenors overreach for multiple reasons.

First, SPEC Services is a "reputable, southern California based pipeline engineering company" capable of providing "an experienced, independent, 3rd party perspective on the cost to replace or pressure test pipe segments."[195] This sentiment was echoed during the PSEP Evidentiary Hearings by witness David Buczkowski, stating that SPEC Services:

> [I]s a company that has quite a bit of experience in doing pipeline work in Southern California. The Gas Company has used them for many, many years. I have worked with them previously. I think they're a reputable company.[196]

Their extensive experience in southern California, not only with SoCalGas but also other utilities, process facilities, and energy infrastructure, has equipped SPEC Services with a keen understanding of what it takes to define the scope and execution requirements that are necessary to prepare cost estimates for natural gas pipelines in our territory. While SPEC's qualifications were not explicitly provided in SoCalGas and SDG&E's testimony, their assumptions and general estimating methodology are outlined in Appendices D and E of our testimony,[197] their qualifications were explained in our data responses,[198] and DRA had an opportunity to ask additional questions during a meet-and-confer session with SPEC Services in October, 2011.[199]

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[194] DRA Opening Brief at 97.
[195] Ex. SCGC-01 (Yap) at Attachment P - Response to DRA-DAO-07-2.
[196] Tr. at 593 (SoCalGas/SDG&E/Buczkowski).
[197] Ex. SCG-09-R (Rivera) Appendices D and E.
[198] Tr. at 875-876 (SoCalGas/SDG&E/Buczkowski).
[199] Tr. at 875-876 (SoCalGas/SDG&E/Buczkowski).

Second, the SPEC Services estimates were reviewed by internal project and construction managers and have since been validated through discussions and information from other utilities.[200] As Mr. Buczkowski explained during hearings: "When we received their cost estimates, we, to the extent that we had time, reviewed them with other construction and project managers within the Gas Company who do this type of work as a backcheck."[201] Additionally, SoCalGas and SDG&E have been in contact with other utilities (PG&E and Peoples Gas in Chicago) to discuss PSEP-related work and concerns.[202] For example, the "$1.4 million a mile for hydrotesting"[203] experienced by PG&E is higher than both DRA and our estimates, supporting the higher estimates developed by SPEC Services. In addition, as Mr. Buczkowski explained during hearings, conversations with "the project and program director for Peoples Gas, William Morrow . . . have validated some of the concerns and risks that we've communicated such as challenges in dealing with construction, general construction permits, street paving requirements."[204] Therefore, although SPEC Services developed the estimates, SoCalGas and SDG&E have worked to check and validate the accuracy of SPEC Services' estimates and methodologies.

### 2. DRA's Hydrotesting Estimates are Flawed

DRA's hydrotesting estimates suffer from a number of flaws, rendering them less applicable than their SoCalGas and SDG&E counterparts. Generally, DRA's uninformed and unsupported estimates discount many of the risks and variables considered and included by SoCalGas and SDG&E. Ignoring risks and variables is not an appropriate way to develop

[200] Tr. at 844; 846-849; 868 (SoCalGas/SDG&E/Buczkowski).
[201] Tr. at 844 (SoCalGas/SDG&E/Buczkowski).
[202] Tr. at 846-849 (SoCalGas/SDG&E/Buczkowski).
[203] Tr. at 847 (SoCalGas/SDG&E/Buczkowski).
[204] Tr. at 848 (SoCalGas/SDG&E/Buczkowski) (Peoples Gas is undertaking a comprehensive program to replace cast iron mains in the City of Chicago).

estimates for a project of the PSEP's scope.  It should be noted that DRA's water cost estimates are significantly lower than the *actual costs* experienced by PG&E.  As discussed during hearings: "You know, they broke it down into water storage at 63 cents a gallon, water handling, 71 cents a gallon, and dewatering and drying at 61 cents a gallon. Without knowing the details of it, you know, these are about 1.20, nearly $2 a gallon for water management cost."[205]  DRA offers no explanation of the significant difference between their estimates and the actual costs experienced by PG&E.  The most rationale explanation for the difference between PG&E's actual costs, SoCalGas and SDG&E's estimates, and DRA's much lower estimates is likely the factors and risks ignored by DRA.  Thus, to accept DRA's estimates as appropriate indications of the costs and risks SoCalGas and SDG&E are likely to experience in implementing their PSEP would significantly undercut cost estimates and ignore the reality of the costs likely to be incurred.

**a. Water Supply**

DRA argues that a "baseline cost of 1 to 2 cents per gallon for supply water is reasonable as shown by the survey data of water utilities and cities in California."[206]  However, DRA's 1 to 2 cent-per-gallon estimate is reached by discounting many factors and risks included in SoCalGas and SDG&E's estimates.[207]

DRA's estimates do not include several elements that would contribute to overall water supply costs.  Specifically, DRA assumes an accessible water hydrant adjacent to the hydrotest. This assumption appears based on assumptions listed in Appendix D of our testimony which states that the estimate "assumes on-site water supply will be available for purchase at one end of

[205] Tr. at 1059-60 (SoCalGas/SDG&E/Buczkowski).
[206] DRA Opening Brief at 84-85.
[207] Ex. SCG-21 (Buczkowski) at 7.

the pipeline segment."[208] This was not intended to presume close proximity to a hydrant. As explained during hearings:

> [T]he basis was not that there would be a hydrant physically located at the beginning of each -- each hydrostatic test segment. I think that would be a very unrealistic and favorable assumption.
>
> You know, the basis includes the, not only the procurement of water but the trucking of water from a location that will vary of course on the specific project, transporting it, you know, to the project site, off-loading it and then being able to use it to actually conduct the pressure test.[209]

By assuming an accessible water hydrant, DRA ignored costs included by SPEC Services related to water filling equipment and personnel, transportation of water, and water off-loading equipment and personnel.[210] Additionally, DRA's estimates did not consider the risk of a high volume water premium or costs associated with municipality coordination and accounts payable for water procurement.[211]

Finally, DRA alleges that SoCalGas and SDG&E's estimates are "double-counting" labor and equipment costs and, in reference to municipality coordination and accounts payable for water procurement, include "[s]ome cost components Sempra claimed are excluded from the water supply cost are actually already included in other parts of the SPEC cost estimate, or are wrong."[212] This is incorrect. The equipment and labor DRA references is to facilitate on-site movement of the source water from the transport truck into the pipeline before the test is initiated and from the pipeline into the Baker tank upon conclusion of the hydrotest.[213] Thus, these costs are separate from the transportation and filling components included in the total hydrotest water

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208 Ex. SCG-21 (Buczkowski) at 7.
209 Tr. at 642 (SoCalGas/SDG&E/Buczkowski).
210 Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-20).
211 Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-20).
212 DRA Opening Brief at 84.
213 Ex. SCG-21 (Buczkowski) at 7.

unit cost.[214] Additionally, the municipality coordination and accounts payable for water procurement costs were considered outside the scope of activities to be covered by Section 4[215] of the SPEC Services cost estimate and were thus appropriately included as a cost factor for water supply.[216]

**b. Water Disposal**

DRA argues that a "reasonable baseline water disposal cost should account for some disposal in storm drains at 1 to 4 cents per gallon, and the balance through private contractors at 8 to 35 cents per gallon, for an average cost lower than 35 cents."[217] DRA's estimates, however, do not take into consideration the possible contamination of water.

As noted during hearings: "our expectation is that there's going to be contaminants that are going to require off-site treatment of water."[218] This expectation was based on the prior experience of SPEC Services, who developed a methodology for pressure testing and included an assumption that the post-test water would be contaminated.[219] This assumption is validated by SoCalGas and SDG&E's inline inspections, which have detected: (1) total Petroleum Hydrocarbons (TPH), as C6 through C44 carbon chains including Benzene (C6H6.), Toluene (CH3), Ethylbenzene (C6H5CH2CH3), and Xylenes (BTEX); (2) Oil and Grease; (3) Metals (aluminum, barium, copper, iron, and manganese); and (4) Polychlorinated Biphenyls (PCBs).[220] For these reasons, all post-test hydrotest water was assumed to be a hazardous liquid.[221] From

214 Ex. SCG-21 (Buczkowski) at 7.
215 DRA alleges that "Municipality coordination" and "accounts payable for water procurement" should be included in the 5% indirect rate for "Planning/Design/Eng/Coord/Procurement" in Section 4 of the SPEC cost estimate. *See* DRA Opening Brief at 84, fn 360.
216 *See* Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-20).
217 DRA Opening Brief at 90.
218 Tr. at 639 (SoCalGas/SDG&E/Buczkowski).
219 Ex. SCG-09-R (Rivera) at Appendix D.
220 Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-28).
221 Discharge permits to surface waters (which generally include storm drains) require meeting the California Toxics Rule (CTR) Standards and screening levels for the Clean Water Act priority pollutants which are essentially

research SPEC Services performed, there are different pricing brackets for non-hazardous and hazardous liquid disposal.

#### c. Banker Tanks Supporting Water Disposal

DRA argues that "Baker tanks should cost approximately $180 a day" based on a $60 rental fee and $120 per day mobilization / demobilization costs.[222]

SoCalGas and SDG&E provided Baker tank estimates of $1,600, but this amount included costs and factors that are required as part of a hydrotest operation and were not considered by DRA. These factors include costs for the Baker tank rental, mobilization and demobilization, a vapor control system, daily tank operations (vapor control technician and hookups), tank cleaning, a Baker tank staging area rental, Baker tank staging, and area site preparation including clearing, grading, and subsequent cleanup.[223]

#### d. Vacuum Trucks Supporting Water Disposal

DRA argues that vacuum trucks supporting water disposal should be included at a "non-overtime rate of $720 per eight-hour day including truck, operator, and fuel."[224]

In SPEC Services' review of historical vacuum truck rental costs for similar projects where hazardous liquids were being transported, SPEC Services found no evidence of daily costs

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equivalent to the drinking water standards. Discharge permits to surface waters also have limits on conventional pollutants (pH, Oil and Grease, Total Suspended Solids, Turbidity, etc.) that are based on local water quality objectives other than toxicity. Discharges to surface waters are regulated by the State Water Resources Control Board (SWRCB) and Regional Water Resources Control Boards (RWQCB) and also must be approved by the local municipality. In addition to meeting the surface waters priority pollutant screening levels, conventional pollutant water quality objectives of the individual Regional RWQCB Basin Plans must be met. Conventional pollutants include pH, Total Suspended Solids, Settable Solids, Oil and Grease, Total Petroleum Hydrocarbons, as well as others. For surface water discharges, toxic constituents must be below the CTR rule values (similar to drinking water purity), but conventional pollutants in surface water discharges must also meet the other RWQCB Basin Plan water quality objectives, some of which apply to surface waters throughout the RWQCB jurisdiction, and others that apply only to specific water bodies within the jurisdiction. Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-11).

[222] DRA Opening Brief at 92.

[223] Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-03).

[224] DRA Opening Brief at 93.

as low as $720 per day.[225] It is not clear what information was communicated to DRA's vendor, such as necessary response time, quantity of trucks, hazmat certifications and contractual requirements for example.[226] However, contributing factors to costs above $720 per day would include a need for multiple vacuum trucks to simultaneously perform hydrotesting at multiple project sites, DOT training and compliance for hazardous material transport, hazardous material handling and transport to specific approved sites, chemically cleaning of vacuum trucks after transport to disposal sites, and general demand conditions that will likely exist during PSEP execution.[227]

**e. Nitrogen Purge Costs**

DRA argues that, based on a 2007 Praxair invoice,[228] nitrogen purge cost estimates should be "approximately $.0016 per SCF."[229]

Despite claims to the contrary, DRA has simply misapplied the unit for nitrogen volume as "CCF" instead of "SCF." Assuming DRA interpreted the 20,148 units of nitrogen to be CCF, they would have calculated a cost of $0.16 per CCF, or $0.0016 per SCF.[230] This confusion is likely due to the unit of measurement shown in column "U/S" being identified as "CCF."[231] This unit of measurement, however, is associated with the "UNIT PRICE" column, not the "UNIT QUANTITY" column.[232] Meaning, Praxair has provided the unit price in CCF, while the unit

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[225] Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-04).
[226] Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-04).
[227] DRA-25 (DRA-TCR-TCAP-PSEP-04-04); Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-05).
[228] Ex. DRA-03 (Roberts) at V-55.
[229] DRA Opening Brief at 94.
[230] CCF means hundred cubic feet and SCF means standard cubic foot. Assuming temperature and pressure agree, 1 ccf = 100 scf.
[231] Ex. DRA-03 (Roberts) at V-55.
[232] Ex. DRA-03 (Roberts) at V-55; *see also* Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-07).

quantity is listed in SCF.[233] Thus, the per SCF amount is calculated by dividing the total bill[234] amount of $3,286.99 by 20,148 SCF -- equaling $0.16 SCF.

The $0.16 per SCF provided by Praxair in this invoice has since increased to $0.19 per SCF due to price escalation between 2007 to 2011, the need to purge multiple segments within a specific hydrotest project, and the assumed minimum of one purge per four miles along the pipeline route resulting in multiple subcontractor mobilizations/demobilizations and labor at each purging location.[235]

For all other pipeline testing and replacement estimate issues, please see our Opening Brief.

### B. Valve Enhancement Plan Cost Estimates

Please see our Opening Brief on this topic.

### C. Interim Safety Cost Estimates

Please see our Opening Brief on this topic.

### D. Cost Estimates to Modify Billing Systems

Please see our Opening Brief on this topic.

### E. Technology Enhancement Estimates

Please see our Opening Brief on this topic.

### F. Enterprise Asset Management System Cost Estimates

Please see our Opening Brief on this topic.

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[233] This is validated by the fact 20,148 SCF must be converted to 201.48 CCF and then multiplied by the .8350 unit price to reach the invoice's nitrogen price of $168.24. Ex. DRA-03 (Roberts) at V-55.

[234] Total bill includes a minimum service charge, nitrogen, pumper hours and miles, technician hours, and a regulatory compliance charge.

[235] Ex. DRA-25 (DRA-TCR-TCAP-PSEP-04-07).

## G. Contingency Estimates

DRA recommends that SoCalGas and SDG&E's pipeline replacement and hydrotesting contingency be reduced from 20-30% to 8%.[236] Prior to this recommendation, however, DRA also recommends shifting a significant amount of risk from estimates and into the contingency. For example, DRA argues that the additional costs included in estimates for water transportation,[237] costs associated with pre-cleaning the pipeline segments,[238] the risk of pipeline contamination and costs to mitigate same,[239] the transportation of hazardous liquids,[240] and cleaning costs associated with transporting hazardous liquids[241] should not be considered in estimates, but included in the contingency. By removing these elements, DRA argues that the hydrotest estimates can be reduced by millions of dollars. However, after proposing to have these costs covered in the contingency, DRA then seeks to reduce the contingency from 20-30% to only 8% -- in effect, removing the costs from our PSEP.

As explained in our Opening Brief and above, SoCalGas and SDG&E provided reasonable estimates and a contingency intended to cover reasonable risks and uncertainties.[242] It is simply not good estimating practice and unreasonable to both eliminate costs from estimates on the mistaken belief that they may be covered by contingencies, but at the same time cut the contingency by more than half. Pressure testing and replacing pipelines is a complicated process that requires extensive planning. Depending on the pipelines location and situation, there can be significant costs that cannot be reasonably anticipated. It is imperative that cost estimates have sufficient contingencies to address these unknowns.

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[236] DRA Opening Brief at 95.
[237] DRA Opening Brief at 85.
[238] DRA Opening Brief at 85.
[239] DRA Opening Brief at 90.
[240] DRA Opening Brief at 93.
[241] DRA Opening Brief at 92-93.
[242] SoCalGas/SDG&E Opening Brief at 148-51.

For all other contingency issues, please see our Opening Brief on this topic.

## VI. ALTERNATIVES TO REPLACEMENT OR PRESSURE TESTING

### A. Proposed Alternatives

Bringing all of our pre-1970 pipelines to 49 CFR Part 192, Subpart J "modern standards" will be costly. As an alternative to eliminating the "grandfathering clause" and requiring that all pipelines be tested to Subpart J standards, SoCalGas and SDG&E propose retaining the ability of California pipeline operators to follow 49 CFR 192.619(c), but also revise GO 112-E to exceed the requirements of 49 CFR 192.619 – requiring safety either be demonstrated by one of four alternative approaches designed to validate the stability of the long seams or pressure tested or replaced.[243]

Using this approach, the "grandfathering clause" would still be used to establish a pre-1970 pipeline's MAOP,[244] but one of four proposed alternative approaches could be used to validate the safety of the pipeline: (1) performing a complete inspection of the pipeline segment using non-destructive examination methods such as ultrasonic, radiographic and magnetic particle inspection techniques;[245] (2) developing rules that would allow for reductions in a grandfathered pipeline's MAOP to serve as an "in service" pressure test for Phase 2 pipeline segments;[246] (3) utilizing Transverse Field Inspection (TFI) tools as part of our Phase 1 process to assess whether advanced inline inspection tools can provide an equivalent means of assessing the integrity of in-service pipelines in Phase 2;[247] and (4) requiring a post-construction strength

[243] Ex. SCG-04 (Schneider) at 45-46.
[244] Tr. at 426 (SoCalGas/SDG&E/Schneider).
[245] SoCalGas/SDG&E Opening Brief at 151-53.
[246] SoCalGas/SDG&E Opening Brief at 154; *see also* Ex. SCG-04 (Schneider) at 60.
[247] SoCalGas/SDG&E Opening Brief at 107-110.

test to at least 1.25 times MAOP, but applying different recordkeeping and testing requirements to pre-November 12, 1970 pipelines and post-November 11, 1970 pipelines.[248]

SoCalGas and SDG&E believe that adoption of some or all of these proposals could, under appropriate circumstances, provide validation of long seam stability that is comparable to the validation provided by pressure testing, while potentially providing greater flexibility and improved cost effectiveness for the testing of pipelines.[249]

### B. Intervenor Response to Proposed Alternatives

Intervenors taking a position regarding our proposed alternatives are either supportive or open to the use of alternatives.[250] SCGC, in particular, provides a detailed and cogent discussion of each of our four proposed alternatives, and calls for the Commission to approve each of the alternatives for use in Phase 1A.[251] We are pleased to find common ground with the intervenors on this topic. And given the contentious nature of this proceeding, the Commission should take notice when all interested parties support any PSEP-related proposal.

### C. Clarifications to Our Proposals

SoCalGas and SDG&E wish to clarify the scope (and proposed timing) of these proposed potential alternatives to pressure testing so that there is no misunderstanding regarding our proposals.[252] Not all of these alternatives currently provide a viable alternative to pressure testing or replacement. Some will need additional analysis and use in the field before we would be comfortable using them as a one-for-one substitute for pressure testing.

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[248] Ex. SCG-04 (Schneider) at 46 (For pipe pressure tested before November 12, 1970, provide records of the test medium and test pressure. For pipe pressure tested after November 11, 1970, provide records in accordance 49 CFR 192.517 that verify compliance with 192.505 or §92.507, as applicable).
[249] *See* Ex. SCG-04 (Schneider) at 47.
[250] *See* SCGC Opening Brief at 40-48; UWUA Opening Brief at 38-40; TURN Opening Brief at 54-55 and 82-83; DRA Opening Brief at 106-07.
[251] SCGC Opening Brief at 40-48.
[252] For example, SCGC appears to be saying that we are proposing to immediately implement each of these proposed alternatives in Phase 1A. See SCGC Opening Brief at 40-48. Our actual proposal is more complicated.

As explained in our testimony, non-destructive examination is a viable alternative to pressure testing or replacement for certain short (i.e., under 1000 feet in length) segments that are susceptible to such examination.[253] This approach would provide additional safety-related information that pressure testing cannot provide, at a much lower cost, and it is ready for implementation now.[254] The other three alternatives we have proposed, however, would require additional use and analysis before SoCalGas and SDG&E would be comfortable actually using them in place of a pressure test.

In particular, we have proposed utilizing TFI tools as part of our Phase 1 process to assess whether advanced inline inspection tools can provide an equivalent means of assessing the integrity of in-service pipelines in Phase 2. TFI would be used in conjunction with pressure testing in Phase 1A, rather than a substitute. Likewise the two other alternatives we have proposed – reductions in a grandfathered pipeline's MAOP to serve as an "in service" pressure test for Phase 2 pipeline segments, and requiring a post-construction strength test to at least 1.25 times MAOP, but applying different recordkeeping and testing requirements to pre-November 12, 1970 pipelines and post-November 11, 1970 pipelines – have not yet been proven to be an equivalent means to pressure testing or replacement.[255] Accordingly, we propose that the Commission direct SoCalGas and SDG&E to work with Commission staff and other interested stakeholders to determine whether, and under what circumstances, these final two alternative methods may be used as an alternative to pressure testing or replacement. If this process is successful, the result would be a further request for authorization by SoCalGas and SDG&E

[253] Ex. SCG-04 (Schneider) at 54-55.
[254] Ex. SCG-04 (Schneider) at 54-55
[255] Ex. SCG-04 (Schneider) at 47 ("We look forward to working with the Commission and other stakeholders to develop these alternatives that demonstrably achieve the same standards as a pressure test.").

(hopefully with the support of the other interested parties), rather than automatic approval based upon the discussions.

### D. Effect of Current State Law and Potential Changes in Federal Regulation on Proposed Alternatives

When SoCalGas and SDG&E originally presented their PSEP, including proposed alternatives to pressure testing and replacement, there was no state or federal law or regulation mandating pressure testing or replacement for pre-1970 pipelines that have been grandfathered under 49 CFR 192.619(c). Since that time, however, the California Legislature has enacted Public Utilities Code Section 958, which provides as follows:

> 958. (a) Each gas corporation shall prepare and submit to the commission *a proposed comprehensive pressure testing implementation plan* for all intrastate transmission lines *to either pressure test those lines or to replace all segments of intrastate transmission lines that were not pressure tested or that lack sufficient details related to performance of pressure testing*. The comprehensive pressure testing implementation plan *shall provide for testing or replacing* all intrastate transmission lines as soon as practicable. The comprehensive pressure testing implementation plan shall set forth criteria on which pipeline segments were identified for *replacement instead of pressure testing*.
>
> (b) The comprehensive *pressure testing implementation plan* shall include a timeline for completion that is as soon as practicable, and includes interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions, prioritization of pressure testing for critical pipelines that must run at or near maximum allowable operating pressure values that result in hoop stress levels at or above 30 percent of specified minimum yield stress, and any other measure that the commission determines will enhance public safety during the implementation period. Engineering-based assumptions may be used to determine maximum allowable operating pressure in the absence of complete records, but only as an interim measure *until such time as all the lines have been tested or replaced*, in order to allow the gas system to continue to operate.
>
> (c) At the completion of the implementation period, all California natural gas intrastate transmission line segments shall meet all of the following:

> (1) Have been *pressure tested*.
>
> (2) Have traceable, verifiable, and complete records readily available.
>
> (3) Where warranted, be capable of accommodating in-line inspection devices.[256]

SoCalGas and SDG&E remain strongly supportive of our proposed alternatives to pressure testing or replacement. With the adoption of Section 958, however, such alternatives would not be legal. Under the statute as written, only pressure testing or replacement will do. If the Commission would issue a conditional authorization for one or more of our proposed alternatives, it would be our intention to seek legislative authorization to use a Commission-approved alternative to pressure testing or replacement, and we would hope that the Commission and interested parties would support us in this endeavor.

That said, SoCalGas and SDG&E need to also note that federal legislation requiring Subpart J pressure testing or replacement for pre-1970 pipelines may be on the horizon. On September 26, 2011, the National Transportation Safety Board (NTSB) issued Recommendation P-11-14, titled "Eliminating Grandfather Clause."[257] This NTSB Recommendation requests that PHMSA delete Section 192.619(a)(3), also known as the "grandfather clause," and require gas transmission pipeline operators to reestablish MAOP using hydrostatic pressure testing. PHMSA reminds operators that this recommendation will be acted upon following the collection of data, including information from the 2013 Gas Transmission and Gathering Pipeline Systems Annual Report, which will allow PHMSA to determine the impact of the requested change on the public

[256] Public Utilities Code Section 958 (adopted October 7, 2011; Effective January 1, 2012).
[257] *See* Pipeline and Hazardous Materials Safety Administration (PHMSA) Advisory Bulletin ADB-2012-06 dated May 1, 2012, at 77 Federal Register 26822.

and industry.[258] If pressure testing or replacement of previously-grandfathered pipelines becomes a federal requirement, any alternatives adopted by the Commission will essentially be meaningless, even if we are able to obtain dispensation to use them from the California Legislature.

# VII. REVENUE REQUIREMENTS

## A. Proposed Revenue Requirements

### 1. Authorization Requested

Please see our Opening Brief on this topic.

### 2. Development of PSEP-Related Revenue Requirements

Please see our Opening Brief on this topic.

### 3. Overhead Loaders

Please see our Opening Brief on this topic.

### 4. Escalation

Please see our Opening Brief on this topic.

### 5. Proposed Case Revenue Requirements

Please see our Opening Brief on this topic.

### 6. Base Case Revenue Requirements

Please see our Opening Brief on this topic.

## B. Intervenor Proposals Relating to Revenue Requirements

### 1. TURN's Proposal for Lower AFUDC Percentages

### 1. TURN's Proposal for Lower AFUDC Percentages

In its Opening Brief, UWUA argues in support of TURN's proposal that that allowance for funds used for construction (AFUDC) for PSEP capital projects should be based upon short-

[258] *Id.*

term interest rates rather than SoCalGas and SDG&E's authorized rates of return (ROR) of 8.68% and 8.40%, respectively.[259] UWUA's AFUDC arguments – most of which are not premised upon record evidence in this proceeding – do not provide a reasonable foundation for the Commission to order changes to our well-established approach to calculating AFUDC.

As explained in our Opening Brief, authorized ROR is an appropriate approximation for the historic recorded AFUDC rates for SoCalGas and SDG&E.[260] 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 Advanced Metering Infrastructure applications.[261] SoCalGas' and SDG&E's use of authorized ROR for AFUDC approximates actual AFUDC, which is derived in accordance with the formula prescribed in the Code of Federal Regulations.[262] In fact, the plant accounting rules referenced by UWUA are in fact the very rules we use to calculate actual AFUDC.

UWUA asserts that AFUDC for our PSEP projects should financed using short-term debt.[263] UWUA also argues, however, that PSEP AFUDC should be based on the 2% figure presented by TURN's witness Mr. Marcus, which has no rationale behind it at all.[264] UWUA is unclear of what they are recommending and simply throwing out low numbers for consideration. As the Commission is well aware, SoCalGas and SDG&E's cost of borrowing is well in excess of 2%, so the position presented by UWUA is really confusing. At least Mr. Marcus does not

[259] *See* UWUA Opening Brief at 33-38. UWUA did not submit testimony on this particular issue.
[260] Ex. SCG-26 (Reyes) at 10.
[261] Ex. SCG-26 (Reyes) at 10.
[262] Ex. SCG-26 (Reyes) at 10. *See* 18 C.F.R. Section 201.3.17 (2012). Per the referenced CFR, AFUDC is one of the standard components of construction costs.
[263] UWUA Opening Brief at 37.
[264] UWUA Opening Brief at 34 (citing Ex. TURN-2 (Marcus) at 8).

attempt to argue that his 2% figure is somehow related to the actual costs SoCalGas and SDG&E will incur to construct these new capital assets.

Bottom line, there is simply no need or justification for changing this established practice, particularly on a one-off basis as TURN and UWUA are proposing in a proceeding that is not devoted to plant accounting issues. Arguments for changing the calculation methodology for AFUDC should be presented in a GRC or other relevant proceeding, not in a phase of our TCAP devoted to consideration of pipeline safety proposals.

For all other AFUDC issues, please see our Opening Brief.

#### 2. SCGC's Recommendation that Non-Destructive Examination Costs be Entirely Expensed

Please see our Opening Brief on this topic.

#### 3. TURN's Proposal for No Incentive Compensation Plan Loader

Please see our Opening Brief on this topic.

#### 4. SCIP/Watson Recommendation for a One-Way TIMP Balancing Account

Please see our Opening Brief on this topic.

## VIII. RATEMAKING TREATMENT FOR RECOVERY OF PHASE 1A COSTS

### A. PSEP Cost Recovery Accounts

Please see our Opening Brief on this topic.

### B. Rate Recovery of Authorized Phase 1A Costs

SCGC proposes that the PSEP Cost Recovery Account should operate similar to SoCalGas' System Reliability Memorandum Account (SRMA).[265] Under the SRMA mechanism, actual costs incurred by the SoCalGas System Operator to maintain flowing supplies on SoCalGas' Southern System are approved via advice letter filing prior to recovery in rates

[265] SCGC Opening Brief at 57-58.

from ratepayers. This is not an appropriate ratemaking treatment for PSEP. PSEP costs can be forecast; Southern System reliability costs cannot. As explained in our testimony and Opening Brief, PSEP costs should be recovered on a forecast basis.

SCGC also makes arguments in its Opening Brief with respect to the calculation of the PSEP surcharge.[266] Pursuant to the Scoping Memo in this proceeding, surcharge calculation is a Phase 2 issue, not a Phase 1 issue. SoCalGas and SDG&E do not agree with SCGC's assertions regarding the calculation of a PSEP surcharge. But neither SCGC's surcharge calculation arguments nor ours are appropriate at this time.

For all other rate recovery issues, please see our Opening Brief.

**C. Rate Recovery of Costs Recorded in PSEP Memorandum Accounts**

DRA questions the reasonableness of the costs included in SoCalGas and SDG&E's memorandum account, stating:

> Given Sempra's inability to explain why some project costs are included in Sempra's workpapers costs estimates for Phase 1A, when another Sempra document says they are excluded, the reasonableness of the costs included in the Memorandum Account is very much in question.[267]

DRA's allegation stems from a perceived discrepancy regarding the inclusion/exclusion of some pipeline project costs listed in Attachment A and SoCalGas and SDG&E's workpapers. This perceived discrepancy, however, results from a lack of understanding of the components included in Attachment A and the workpapers.

For purposes of developing Attachment A, if a particular pipeline had both replacement and pressure test scope proposed in the PSEP, it was denoted as two separate line items in the document. In some cases one component is entirely post-1970 and the other component is

[266] SCGC Opening Brief at 60-61.
[267] DRA Opening Brief at 114.

entirely pre-1970. The line item on Attachment A for the post-1970 component would be accompanied by a note that costs are not included. The workpapers similarly do not show costs for this *post*-1970 scope. The *pre*-1970 component included in the PSEP, however, will have costs shown in the workpapers. Mr. Rivera explained a specific example at hearings:

> Just a point of clarification that there is two sets of costs for 49-18, and there may be others here that I haven't verified. 49-18 has two different components. It had a small hydrotest piece that is part of the post-1970 segments, and then it has a capital piece. So the capital piece of this project is still in the PSEP. So on the workpapers when you look at the workpaper for 49-18, this is capital workpaper, it shows $33 million. That $33 million is still a viable project that is part of PSEP. What has been removed is the smaller O&M portion of the hydrotest.[268]

For all other issues related to this topic, please see our Opening Brief.

### D. Expedited Advice Letter for Proposed Adjustments to PSEP Funding

Please see our Opening Brief on this topic.

### E. Annual PSEP Update Report

Please see our Opening Brief on this topic.

## IX. ADDITIONAL INTERVENOR PROPOSALS

### A. Proposed Notice Requirement

Please see our Opening Brief on this topic.

### B. Local Transmission Interruption Credit Proposal

Please see our Opening Brief on this topic.

### C. BTS Reservation Charge Credit Proposal

Please see our Opening Brief on this topic.

### D. UWUA O&M Proposals

Please see our Opening Brief on this topic.

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[268] Tr. at 1322 (SoCalGas/SDG&E/Rivera).

### E. Treatment of Robotics Royalties

Please see our Opening Brief on this topic.

## X. PHASE 1B

### A. Line 1600

As explained in our Opening Brief and testimony, Line 1600 is a Phase 1B construction project.[269] While some of the pipeline meets the criteria for replacement in Phase 1A, the need to construct a replacement pipeline before removing Line 1600 from service for testing pushes this project into Phase 1B.[270] In order to complete the construction of this pipeline project within the Phase 1B timeframe, however, SoCalGas and SDG&E have sought recovery of certain Line 1600 pre-engineering costs in Phase 1A.

SCGC asserts that SoCalGas and SDG&E should not be authorized to do even pre-engineering work for Line 1600 in Phase 1A: "given that the Applicants have already taken the interim safety measure of reducing the pressure of Line 1600, and given that utilizing the TFI technology on Line 1600 could obviate the substantial costs of constructing a 36-inch pipeline and even obviate the cost of pressure testing Line 1600, no costs should be incurred for Line 1600 in Phase 1A."[271] SoCalGas and SDG&E believe this recommendation is short-sighted, and inconsistent with the Commission's efforts to promote timely implementation of its new pipeline safety standards.

The only costs related to Line 1600 that SoCalGas and SDG&E have proposed for Phase 1A are those necessary to perform an inline inspection and begin the pre-engineering for the replacement pipeline.[272] These pre-engineering costs represent only 4% of the total replacement

[269] SoCalGas/SDG&E Opening Brief at 191; Ex. SCG-22 (Bisi) at 5.
[270] Ex. SCG-22 (Bisi) at 7-8.
[271] SCGC Opening Brief at 73.
[272] Ex. SCG-22 (Bisi) at 6.

pipeline costs.[273] 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.[274] Moreover, deferring necessary pre-engineering work for Line 1600 to Phase 1B will delay the entire project to test the pipeline, and thus almost certainly extend it past the Phase 1B timeframe.[275] This work is necessary to serve the needs of customers located in San Diego County, and should not be delayed beyond Phase 1B.

SoCalGas and SDG&E agree with SCGC that TFI technology is promising, and do believe that lower operating pressures on Line 1600 have created a safety margin.[276] 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 develop a safety plan which follows the rules and requirements established by the Commission and the state legislature. As such, Line 1600 needs to 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.[277] 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.[278]

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[273] Ex. SCG-22 (Bisi) at 6.
[274] Ex. SCG-22 (Bisi) at 6.
[275] Ex. SCG-22 (Bisi) at 6.
[276] Ex. SCG-22 (Bisi) at 6.
[277] Ex. SCG-22 (Bisi) at 7.
[278] R.11-02-019, January 17, 2012 Technical Report of CPSD Regarding the SoCalGas and SDG&E PSEP at p. 5.

For all of these reasons, the Commission should reject SCGC's recommendations with respect to Line 1600. In order to facilitate the pressure testing of Line 1600 within a reasonable timeframe, SoCalGas and SDG&E should be authorized to conduct the limited Line 1600 pre-engineering work that they have proposed for Phase 1A.

For all other Phase 1B issues, please see our Opening Brief.

## XI. PHASE 2

Please see our Opening Brief on this topic.

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## XII. CONCLUSION

For the reasons set forth above, in their Amended PSEP, in their testimony, and in their Opening Brief, SoCalGas and SDG&E respectfully request that the Commission adopt each of the proposals submitted by SoCalGas and SDG&E in this proceeding, reject each of the contrary proposals by intervenors, and adopt each of the proposed recommendations set forth at the beginning of their Opening Brief.

Dated this 9th day of November 2012, in Los Angeles, California.

Respectfully submitted,

SOUTHERN CALIFORNIA GAS COMPANY
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