BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for (A) Approval of the Forecasted Revenue Requirement Associated with Certain Pipeline Safety Enhancement Plan Projects and Associated Rate Recovery, and (B) Authority to Modify and Create Certain Balancing Accounts	Application 17-03-021 (Filed on March 30, 2017)

MOTION FOR OFFICIAL NOTICE IN SUPPORT OF THE REPLY BRIEF OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G) IN SUPPORT OF THEIR APPLICATION FOR (A) APPROVAL OF THE FORECASTED REVENUE REQUIREMENT ASSOCIATED WITH CERTAIN PIPELINE SAFETY ENHANCEMENT PLAN PROJECTS AND ASSOCIATED RATE RECOVERY, AND (B) AUTHORITY TO MODIFY AND CREATE CERTAIN BALANCING ACCOUNTS

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April 16, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for (A) Approval of the Forecasted Revenue Requirement Associated with Certain Pipeline Safety Enhancement Plan Projects and Associated Rate Recovery, and (B) Authority to Modify and Create Certain Balancing Accounts	Application 17-03-021 (Filed on March 30, 2017)

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Pursuant to Rules 11.1 and 13.9 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (jointly, "Applicants") hereby respectfully request official notice of the following documents attached to this motion.

1. Exhibit A, Revised Direct Testimony of Rick Phillips, Pipeline Safety and Enhancement Plan (PSEP), in A.17-10-008 dated March 2018, available at http://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1710008/1259/212498296.pdf.
2. Exhibit B, Presidential Proclamation on Adjusting Imports of Steel into the United States (March 8, 2018), available at https://www.whitehouse.gov/presidential-actions/presidential-proclamation-adjusting-imports-steel-united-states.
3. Exhibit C, Amended Chapter II Direct Testimony of Rick Phillips, in A.16-09-005 dated November 20, 2017, available at https://www.socalgas.com/regulatory/documents/a-16-09-005/Chapter_02_Phillips-Execution_Amended_11-20-17-CLEAN-w%20Attach_A_B_C.pdf.
4. Exhibit D, Excerpt from Amended Workpapers from Pipeline Safety and Enhancement Plan (PSEP) 2016 Reasonableness Review in A.16-09-005 dated November 20, 2018,

available at https://www.socalgas.com/regulatory/documents/a-16-09-005/Chapter_02_Phillips-Execution_Amended_11-20-17-CLEAN-w%20Attach_A_B_C.pdf.

5. Exhibit E, Opening Brief of the Utility Reform Network on Pipeline Safety Enhancement Plan Issues in A.11-11-002 (Nov. 1, 2011) available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K734/31734962.PDF.
6. Exhibit F, Southern California Generation Coalition Opening Brief in A.11-11-002 (October 19, 2012) available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K743/31743972.PDF.
7. Exhibit G, Southern California Generation Coalition Reply Brief in A.11-11-002 (November 9, 2012) available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K744/31744230.PDF.

I. INTRODUCTION

According to Rule 13.9 of CPUC Rules of Practice and Procedure, "[o]fficial notice may be taken of such matters as may be judicially noticed by the courts of the State of California pursuant to Evidence Code section 450 et seq." Judicial notice may be taken of official acts of executive branch, "[r]ecords of . . . any court of this state," and "[f]acts and propositions that are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy." Cal. Evid. Code § 452(c), (d) & (h).

The documents attached to this motion are appropriate for official notice because they are (1) records from Applicants' 2019 General Rate Case proceeding concerning the Pipeline Safety Enhancement Plan (PSEP); (2) records from Applicants' prior PSEP proceedings; and (3) a presidential proclamation. Official notice is proper as these documents are records of CPUC and the White House and are capable of immediate and accurate determination by the Commission by searching the Commission's dockets as well as the White House website.

II. OFFICIAL NOTICE IS APPROPRIATE FOR RECORDS OF THE CPUC

Submissions in CPUC proceedings may be judicially noted. *See Goncharov v. Uber Techns., Inc.*, 19 Cal. App. 5th 1157, 1161 n.2 (2018) (judicially noting rulings, submissions, scoping memoranda, and proposed decisions from CPUC proceedings).

Here, witness testimony, workpapers, and briefs in the 2019 GRC proceeding and prior PSEP proceedings are submissions in CPUC proceedings that may be judicially noticed. They are publicly available on websites, and the Commission can readily verify that they were submitted in conjunction with relevant CPUC proceedings.

III. OFFICIAL NOTICE IS APPROPRIATE FOR PUBLICLY AVAILABLE PRESIDENTIAL PROCLAMATION

Executive proclamations may be judicially noted. Cal. Evid. Code § 452(c); s*ee, e.g.*, *Vowinckel v. First Fed. Tr. Co.*, 10. F.2d 19, 20 (9th Cir. 1926); *City of Santa Clara v. Trump*, 275 F. Supp. 3d 1196, 1208 (N.D. Cal. 2017).

Here, the Presidential Proclamation on Adjusting Imports of Steel into the United States, dated March 8, 2018 should be judicially noted because it is relevant official act of the executive branch that is publicly available on the White House website.

IV. INTERVENORS WILL NOT BE PREJUDICED

The Office of Ratepayer Advocates, Southern California Generation Coalition, and The Utility Reform Network ("Intervenors") will not be prejudiced as they are all parties to the Applicants' 2019 GRC proceeding and were parties to prior PSEP proceedings in which these documents were first introduced. Moreover, the presidential proclamation is available on a public website and has been the subject of much media coverage.

V. CONCLUSION

Because the documents are publicly available information, relevant to this proceeding, and the intervenors will not be prejudiced, it is appropriate for the Commission to take official notice of the foregoing documents. Therefore, Applicants respectfully request that the Commission take official notice of (1) the testimony of Rick Phillips, (2) the workpapers for a project in a prior PSEP proceeding, (3) the Presidential Proclamation on Adjusting Imports of Steel into the United States, and (4) TURN's and SCGC's briefs in prior PSEP proceedings.

Respectfully submitted on behalf of SoCalGas and SDG&E,

By: */s/ Avisha A. Patel*
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April 16, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for (A) Approval of the Forecasted Revenue Requirement Associated with Certain Pipeline Safety Enhancement Plan Projects and Associated Rate Recovery, and (B) Authority to Modify and Create Certain Balancing Accounts	Application 17-03-021 (Filed on March 30, 2017)

[PROPOSED] RULING

Pursuant to Rules 11.1 and 13.9 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (jointly, "Applicants") filed a Motion for Official Notice ("Motion") of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) in Support of Their Reply in support of Their Application for (A) Approval of the Forecasted Revenue Requirement Associated with Certain Pipeline Safety Enhancement Plan Projects and Associated Rate Recovery, and (B) Authority to Modify and Create Certain Balancing Accounts ("Application").

The Motion sets forth the reasons for the Commission taking official notice of the documents proposed by Applicants, including, *inter alia*, that the documents include records of this Commission in related and relevant proceedings and a presidential proclamation accessible on the White House website.

Therefore, it is ruled that the Commission shall take the official notice of the following:

1. Exhibit A, Revised Direct Testimony of Rick Phillips, Pipeline Safety and Enhancement Plan (PSEP) in A.17-10-008 dated March 2018, available at http://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1710008/1259/212498296.pdf.
2. Exhibit B, Presidential Proclamation on Adjusting Imports of Steel into the United States (March 8, 2018), available at https://www.whitehouse.gov/presidential-actions/presidential-proclamation-adjusting-imports-steel-united-states.

3. Exhibit C, Amended Chapter II Direct Testimony of Rick Phillips in A.16-09-005 dated November 20, 2017, available at https://www.socalgas.com/regulatory/documents/a-16-09-005/Chapter_02_Phillips-Execution_Amended_11-20-17-CLEAN-w%20Attach_A_B_C.pdf.
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7. Exhibit G, Southern California Generation Coalition Reply Brief in A.11-11-002 (November 9, 2012) available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K744/31744230.PDF.

IT IS SO ORDERED.

Dated: ______________________ ____________________________________

Administrative Law Judge

EXHIBIT A

Company: Southern California Gas Company (U 904 G)
Proceeding: 2019 General Rate Case
Application: A.17-10-008
Exhibit: SCG-15-R

REVISED

SOCALGAS

DIRECT TESTIMONY OF RICK PHILLIPS
(PIPELINE SAFETY AND ENHANCEMENT PLAN (PSEP))

March, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

SoCalGas
A Sempra Energy utility®

318175

TABLE OF CONTENTS

SUMMARY

Summary of Requests

- Authorize SoCalGas to proceed with construction of the eleven Phase 2A pressure test projects, one Phase 2A replacement project, and ten Phase 1B replacement projects presented in this Application.
- Authorize SoCalGas to continue construction of the 284 valve project bundles presented in this Application in furtherance of the continuing implementation and execution of the PSEP Valve Enhancement Plan mandated by the Commission in D.14-06-007.
- Authorize recovery in rates of $249,467,456 O&M ($83,155,819 in each of years 2019, 2020, 2021) and revenue requirement associated with $649,326,239 Capital (years 2017-2021), each on an aggregate basis, for the pipeline and valve projects presented in this Application in furtherance of the continued implementation and execution of the Pipeline Safety Enhancement Plan (PSEP) mandated by the Commission in Decision (D.) 14-06-007 and D.16-08-003.
- Authorize SoCalGas to continue to record and balance PSEP costs in a two-way balancing account, the Pipeline Safety Enhancement Plan Balancing Account (PSEPBA).
- Authorize SoCalGas to substitute PSEP pipeline or valve projects approved in this Application with one or more other PSEP projects in the event construction of an approved project is delayed.
- Clarify State policy regarding transmission pipelines that have documentation of a pressure test that pre-dates the adoption of federal pressure testing regulations in 1970.

Tables RDP-1 and RDP-2 depict where in my testimony the various O&M and Capital components of my request can be located.

Table RDP-1
Southern California Gas Company
Summary of O&M
(Direct Costs – Thousands)

Component	Total 2019-2021	Testimony Page
Pressure Test	$236,379[1]	RDP-25
Misc PSEP Costs	$15,573	RDP-41
Total O&M	**$251,952**	

Table RDP-2
Southern California Gas Company
Summary of Capital Expenditures
(Direct Costs – Thousands)

Component	2015-2016	2017-2019	2020-2021	Total	Testimony Page
Pressure Test Projects	$15	$1,613	$62,814	$64,443	RDP-25
Misc PSEP Costs	$0	$13,878	$23,756	$37,634	RDP-41
Replacement Projects	$8,140	$35,682	$257,428	$301,250	RDP-47
Valve Enhancement Plan	$0	$101,680	$144,320	$246,000	RDP-56
Total Capital	**$8,155**	**$152,853**	**$488,318**	**$649,326**	

[1] Includes $2,484K recorded in Pipeline Safety Enhancement Plan – Phase 2 Memorandum Account (PSEP-P2MA), amortization of which will be sought in a future proceeding.

SOCALGAS DIRECT TESTIMONY OF RICK PHILLIPS
(PIPELINE SAFETY AND ENHANCEMENT PLAN (PSEP))

I. INTRODUCTION

A. Summary of PSEP Costs and Activities

My testimony supports Southern California Gas Company's (SoCalGas)[2] request for Commission approval to proceed with construction of eleven Phase 2A pressure test projects, one Phase 2A replacement project, ten Phase 1B replacement projects, continuation of the Valve Enhancement Plan, and miscellaneous other costs in the continuing implementation of the Pipeline Safety Enhancement Plan (PSEP) mandated by the Commission in Decisions (D.) 14-06-007 and 16-08-003. In Section II of the following direct testimony, I provide the historical and procedural background of PSEP and its segue to the General Rate Case (GRC). In Section III, I review the current overall scope of PSEP, which is divided into four phases—Phases 1A, 1B, 2A and 2B—and includes a Valve Enhancement Plan, and describe how SoCalGas will continue to execute PSEP in a prudent manner. I address PSEP costs related to the Fueling our Future (FOF) initiative, Aliso Incident, and how PSEP directly supports the Risk Assessment Mitigation Phase (RAMP) and the SoCalGas safety culture in Sections IV, V and VI, respectively. Sections VII (Pressure Test Projects, VIII (Miscellaneous PSEP Costs), and IX (Capital) of my testimony provide an overview of each project included in this Application.[3] I describe the forecast methodology used to develop the detailed cost estimates presented for approval, including a description of the estimate components, PSEP Decision Tree, and PSEP Seven Stage Review Process. In Section VIII, I review additional miscellaneous PSEP implementation costs, including future design and PSEP Program Management (PMO) costs, along with an estimated cost summary. A list of projects to be executed if the Commission grants SoCalGas' request to extend the duration of SoCalGas' rate case cycle to include a fourth year, and the forecasted costs of completing that work, is presented in Section X. In Section XII,

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[2] There are no SDG&E Phase 1B or 2A PSEP projects included in this Application.
[3] Detailed information regarding the forecasted costs for each project is included in the supplemental workpapers accompanying this chapter. The supplemental workpapers also includes an overview of typical project activities, a glossary of key terms, and illustrative photographs of typical PSEP projects. The information provided in this chapter is intended to provide a summary of the projects and the forecasted costs.

I request authority to substitute PSEP projects, should a delay in construction outside of SoCalGas' control be encountered on one of the projects presented in this Application. Finally, in Section XIII, I request clarification of the Commission's directives to bring pipelines into compliance with "modern" pressure testing standards.

II. PROCEDURAL HISTORY AND BACKGROUND

A. Procedural History and Regulatory Framework

On September 9, 2010, a 30-inch diameter natural gas transmission pipeline ruptured and caught fire in the city of San Bruno, California. In response, the Commission, on February 25, 2011, issued Rulemaking (R.) 11-02-019, "a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines."[4]

In a subsequent decision, D.11-06-017, the Commission found that "natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety," and ordered all California natural gas transmission pipeline operators "to prepare and file a comprehensive Implementation Plan to replace or pressure test all natural gas transmission pipeline in California that has not been tested or for which reliable records are not available."[5] The Commission required that the plans provide for testing or replacing all such pipelines "as soon as practicable."[6] The Commission required that the plans "also address retrofitting pipelines to allow for in-line inspection tools and, where appropriate, automated or remote controlled shut off valves"[7] and "includ[e] increased patrols and leak surveys, pressure reductions, prioritization of pressure testing for critical pipelines that must run at or near Maximum Allowable Operating Pressure (MAOP) values which result in hoop stress levels at or above 30% of Specified Minimum Yield Stress (SMYS), and other such measures that will enhance public safety during the implementation period."[8] The requirements of D.11-06-017 were later codified at California Public Utilities Code Sections 957 and 958.

On August 26, 2011, SoCalGas and SDG&E filed their proposed PSEP. The PSEP included, among other things, a proposed Decision Tree to guide whether specific segments

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[4] R,11-02-019 at 1.
[5] D.11-06-017 at 18.
[6] *Id.* at 19.
[7] *Id.* at 21.
[8] *Id.* at 31 (Ordering ¶ 5).

should be pressure tested, replaced, or abandoned; a proposed valve enhancement plan; a proposed technology plan; and preliminary cost forecasts.[9]

In D.12-04-021, the Commission transferred SoCalGas and SDG&E's PSEP to A.11-11-002 (SoCalGas and SDG&E's Biennial Cost Allocation proceeding) and authorized SoCalGas and SDG&E to create a "memorandum account to record for later Commission ratemaking consideration the escalated direct and incremental overhead costs of its Pipeline Safety Enhancement Plan."[10] On May 18, 2012, certain memorandum accounts (PSRMAs) were established pursuant to SoCalGas and SDG&E Advice Letters 4359 and 2106-G.

In June 2014, the Commission issued D.14-06-007, which approved the proposed PSEP and "adopt[ed] the concepts embodied in the Decision Tree," "adopt[ed] the intended scope of work as summarized by the Decision Tree," and "adopt[ed] the Phase 1 analytical approach for Safety Enhancement…as embodied in the Decision Tree…and related descriptive testimony."[11] The Commission also directed the utilities to develop plans to "test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test. . . .as soon as practicable."[12] The plans are to address "[a]ll natural gas transmission pipeline… even low priority segments,"[13] while also "[o]btaining the greatest amount of safety value, i.e., reducing safety risk, for ratepayer expenditures…"[14] In this decision approving SoCalGas and SDG&E's proposed plan, the Commission acknowledged the broad scope of SoCalGas and SDG&E's PSEP:

> In addition to the testing or replacing pipeline, Safety Enhancement includes modifications of 541 valves, and the addition of 20 valves, to provide for automated shut-off capability in order to isolate, limit the flow of gas to no more than 30 minutes, and thereby facilitate timely access of "first responders" into the area surrounding a substantial section of ruptured pipe. Safety Enhancement also includes: 1) improvements to communications and data gathering to ascertain

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[9] On December 2, 2011, SoCalGas and SDG&E amended their PSEP to include supplemental testimony to address issues identified in R.11-02-019, "Amended Scoping Memo and Ruling of the Assigned Commissioner," filed November 2, 2011.

[10] D.12-04-021 at 12 (Ordering Paragraphs 1, 3). SoCalGas and SDG&E were authorized to continue to record and report on PSEP costs in the PSMRAs per the July 26, 2013 Administrative Law Judge's Ruling to Continue Tracking Interim Pipeline Safety Enhancement Plan Costs in Authorized Memorandum Accounts.

[11] D.14-06-007 at 22, 59 (Ordering Paragraph 1).

[12] D.11-06-017 at 19.

[13] *Id.* at 20.

[14] *Id.* at 22.

pipeline conditions; 2) installing backflow valves to prevent gas from flowing into sections intended to be isolated from other connected lines; 3) expand the coverage of SDG&E and SoCalGas' private radio networks to serve as back-up to other available means of communications with the newly installed valves to improve system reliability; 4) installing remote leak detection equipment; and 5) increasing physical patrols and leak survey activities.[15]

Rather than pre-approve cost recovery based on SoCalGas and SDG&E's preliminary cost forecasts, the Commission adopted a process for reviewing and approving PSEP implementation costs after-the-fact.[16]

To enable the after-the-fact review of PSEP costs, D.14-06-007 required SoCalGas and SDG&E to establish certain additional balancing accounts (SECCBAs and SEEBAs) to record PSEP expenditures.[17] Additionally, to recover PSEP costs, SoCalGas and SDG&E were ordered to "file an application with testimony and work papers to demonstrate the reasonableness of the costs incurred which would justify rate recovery."[18]

In December 2014, SoCalGas and SDG&E filed an application requesting the Commission find reasonable the costs incurred to implement PSEP projects, as well as the associated revenue requirement, recorded in the PSRMAs before June 12, 2014. The Commission found that SoCalGas and SDG&E's actions and expenses were reasonable and consistent with the reasonable manager standard, with one exception related to insurance coverage, and granted the application.[19]

B. Commission Directive to Transition PSEP into the GRC

In Application (A.) 15-06-003 (*Application of SoCalGas and SDG&E to Proceed with Phase 2 of their Pipeline Safety and Enhancement Plan and Establish Memorandum Accounts to Record Phase 2 Costs*), the assigned Administrative Law Judge issued a ruling requesting parties to meet and confer to develop a procedural plan focused on bringing PSEP work within the GRC regulatory process and to develop a comprehensive plan to address PSEP costs expected to be

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[15] D.14-06-007 at 8.

[16] The Commission did determine in D.14-06-007, however, that certain PSEP costs should be disallowed (*see* Section 6, "Ratemaking Principles to be Applied in Reasonableness Applications," at 31-39).

[17] *Id.* at 60 (Ordering Paragraph 4).

[18] *Id.* at 39.

[19] *See* D.16-12-063, granting A.14-12-016. The decision declined to authorize recovery of costs for PSEP-specific insurance (without prejudice) after determining that SoCalGas and SDG&E did not make a sufficient factual showing in the Application to support the reasonableness of those costs. *Id.*, at 54.

incurred prior to the next GRC test year. In resolving SoCalGas and SDG&E's application, the Commission approved an Energy Division proposal detailing a framework to transition PSEP into SoCalGas and SDG&E's next GRCs. Specifically, D.16-08-003 provided for two additional standalone applications for after-the-fact review of the costs incurred to complete Phase 1A projects and one forecast application for authorization to recover the costs of Phase 2 projects. All Phase 1A projects completed after the filing of the two reasonableness reviews, as well as remaining forecasted projects not included in the forecast application, are to be submitted for approval in the Test Year 2019 (TY 2019) and subsequent GRCs.[20] The first of the two reasonableness review applications, A.16-09-005, was filed in September 2016 (2016 RR Application), and SoCalGas and SDG&E anticipate filing the second reasonableness review in 2018. The forecast application, A.17-03-021, was filed in March 2017 (2017 Forecast Application).

III. PSEP OVERVIEW

The primary objective of PSEP is to: (1) enhance public safety; (2) comply with Commission directives; (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments. As directed by the Commission, the SoCalGas and SDG&E PSEP includes a risk-based prioritization methodology that prioritizes pipelines located in more populated areas ahead of pipelines located in less populated areas and further prioritizes pipelines operated at higher stress levels above those operated at lower stress levels. To implement this prioritization process, the PSEP is divided into two initial Phases, Phase 1 and Phase 2, and these two phases are further divided into two parts, Phases 1A and 1B, and Phases 2A and 2B. The scopes of these phases are described in greater detail in the following subsections.

A. Scope of Phase 1A

Phase 1A encompasses pipelines located in Class 3 and 4 locations and Class 1 and 2 locations in high consequence areas (HCAs)[21] that do not have sufficient documentation of a pressure test to at least 1.25 times the MAOP. SoCalGas and SDG&E anticipate completing

[20] D.16-08-003 at 16 (Ordering Paragraph 5).
[21] Class Locations as defined in Part 192.5 of Title 49 of the Code of Federal Regulations.

Phase 1A work in 2019. In accordance with D.14-06-007, as amended by D.16-08-003, SoCalGas and SDG&E will request cost recovery for Phase 1A projects consistent with the regulatory framework established by the Commission and described above.

B. Scope of Phase 1B

The scope of Phase 1B, as outlined in SoCalGas and SDG&E's PSEP, is to replace non-piggable pipelines installed prior to 1946[22] with new pipe constructed using state-of-the-art methods and to modern standards, including current pressure test standards. The Commission ordered this work in directing California pipeline operators to "address retrofitting pipeline to allow for in-line inspection tools" in D.11-06-017. "Non-piggable" pipelines cannot accommodate in-line inspection tools that assess pipeline integrity. Pre-1946 pipelines were built using non-state-of-the-art construction methods (i.e., oxy-acetylene welds that inherently are brittle) and materials (i.e., pipe manufacturers used various non-state-of-the art manufacturing processes), were not designed to accommodate a post-construction pressure test, and have an increased risk of developing leaks on girth welds.

Table RDP-3 depicts the various vintages of Phase 1B pipe proposed to be replaced in this Application:

Table RDP-3
Southern California Gas Company
Phase 1B Projects by Vintage

Year Installed	Miles	Number of Projects
1920-1929	9	6
1930-1939	59	2
1940-1945	3	2
Total	**71**	**10**

SoCalGas and SDG&E included nine Phase 1B projects in the 2017 Forecast Application, ten Phase 1B projects are presented in this Application, and the remainder (currently estimated to be three) are anticipated to be included in the next GRC. The ten

[22] The scope of Phase 1B in the SoCalGas and SDG&E Amended PSEP Application also included those pipeline segments that otherwise would be addressed in Phase 1A but cannot be addressed in the near term due to the need to construct new infrastructure to maintain service during pressure testing. The Pipeline Safety and Reliability Project (A.15-09-013) addresses this aspect of Phase 1B (Line 1600), as defined in the Amended PSEP Application.

Phase 1B projects included in this filing will replace pipe that was originally installed over 70 years ago, with over 95% of the pipe installed over 80 years ago.

C. Scope of Phase 2A

As previously mentioned, Phase 1 entails pressure testing or replacing transmission pipelines in Class 3 and 4 locations and Class 1 and 2 locations in HCAs that do not have sufficient documentation of a pressure test to at least 1.25 MAOP and replacing non-piggable pipe installed prior to 1946.

Whereas Phases 1A and 1B address pipelines located in more populated areas and pre-1946 non-piggable pipe, Phase 2A addresses the remaining transmission pipelines that do not have sufficient documentation of a pressure test to at least 1.25 MAOP and are located in Class 1 and 2 non-high consequence areas. SoCalGas currently estimates approximately 700 miles of pipeline in Phase 2A do not have sufficient documentation of a pressure test to at least 1.25 times the MAOP.[23] SoCalGas anticipates that approximately 90% of these miles will be pressure tested and the remaining 10% will be replaced. For the Phase 2A projects included in this filing, SoCalGas proposes to pressure test all but about 1,900 feet of the approximately 200 miles presented.[24]

SoCalGas and SDG&E included three Phase 2A projects in the 2017 Forecast Application, eleven Phase 2A projects are presented for Commission consideration in this Application, and remaining projects will be included in subsequent GRCs. Phase 2A is currently anticipated to be completed in 2026.

1. Phase 2A Decision Tree

The process of determining if a Phase 2A pipe segment is to be pressure tested or replaced follows the logic of the Decision Tree principles approved by the Commission in

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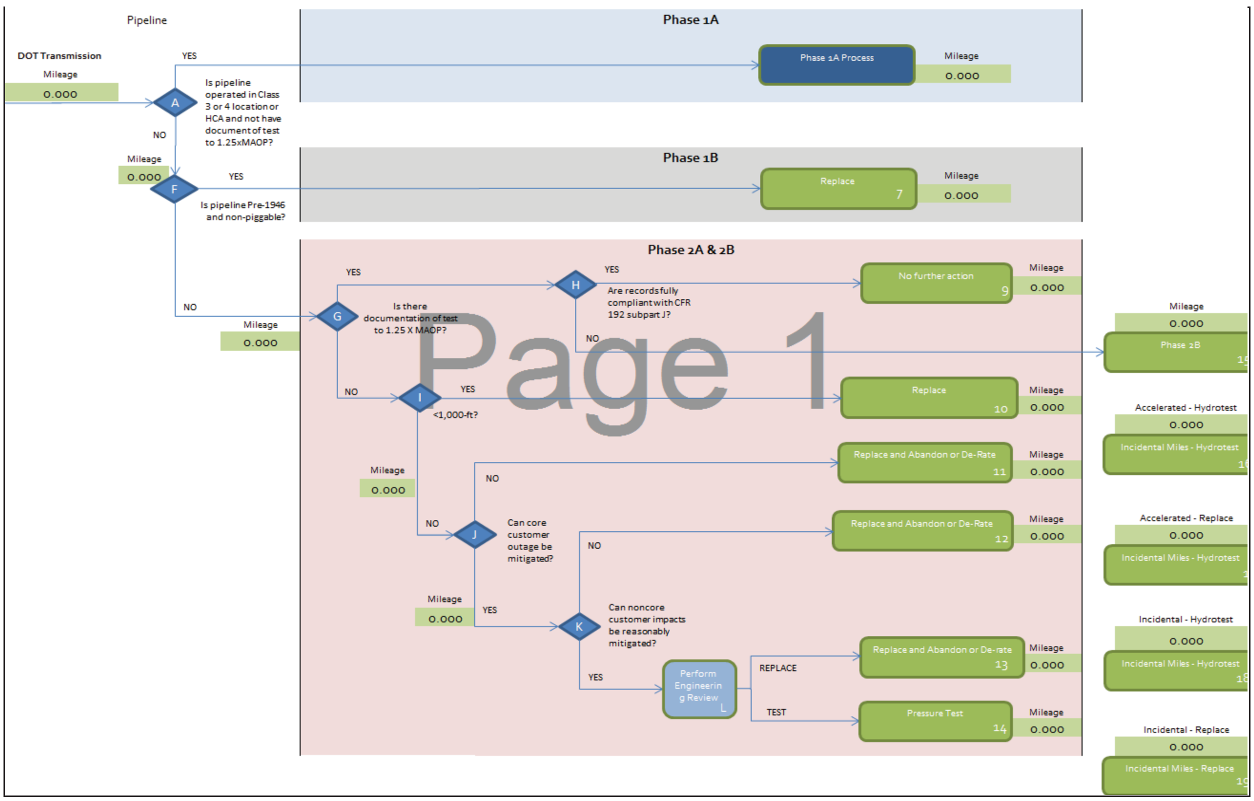
[23] As part of a seven stage review process, SoCalGas carefully reviews pipeline records and operational needs before initiating construction activity on a pipeline project. Through this process, SoCalGas anticipates some portion of remaining Phase 2A miles may be descoped from PSEP through the identification of pipeline records or other means (such as lowering of MAOP) that eliminate the need to pressure test or replace the pipeline segments.

[24] In addition, approximately two miles will be replaced as part of the normal testing process. A portion of the existing pipeline is removed to accommodate the temporary test heads that are used to conduct hydrostatic pressure testing. After the line is tested and the temporary test heads are removed, a new section of pipe is installed in place to "tie-in" the pressure-tested segment to the pipeline on either side of the segment.

D.14-06-007.[25] Figure RDP-1 depicts a Decision Tree that applies to Phase 2A the same principles approved by the Commission for Phase 1. For comparison purposes, Figure RDP-2 depicts the Phase 1 Decision Tree approved in D.14-06-007.

Figure RDP-1
Southern California Gas Company
Phase 2A Decision Tree



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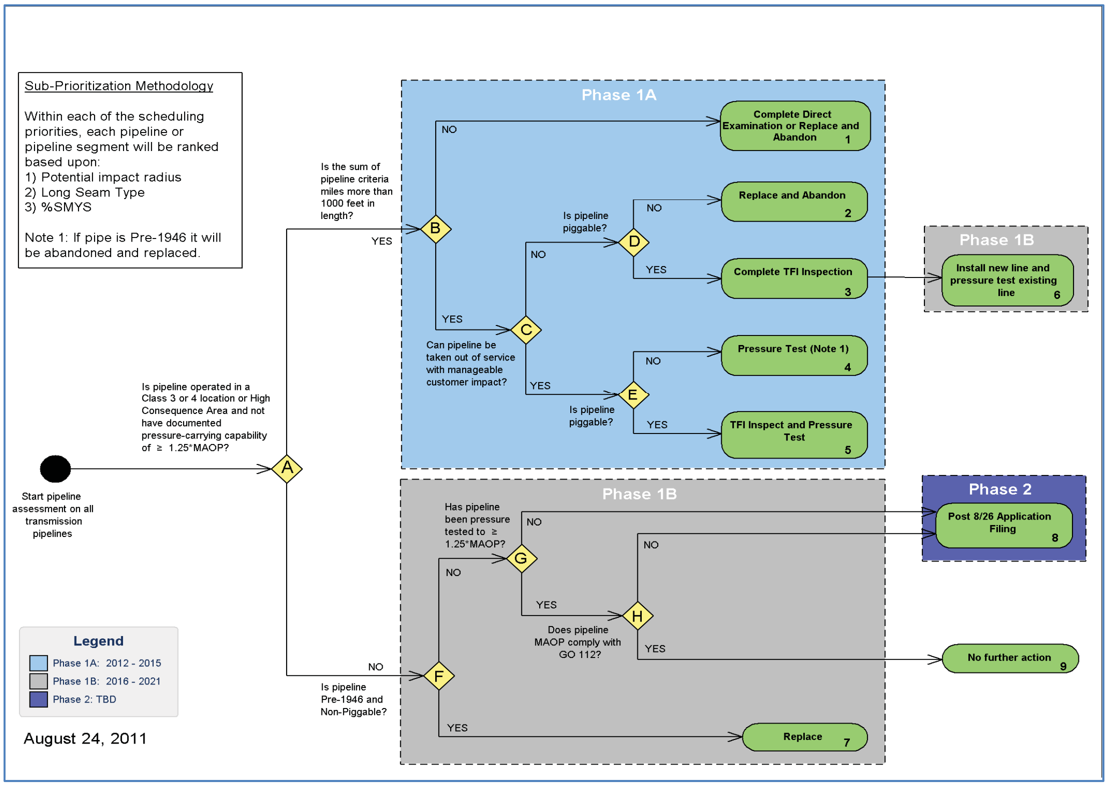
[25] D.14-06-007 at 59 (Ordering Paragraph 1).

Figure RDP-2
Southern California Gas Company
Phase 1 Decision Tree



Like the Commission-approved Phase 1 Decision Tree, the Phase 2A Decision Tree uses a step-by-step analysis of pipeline segments to allocate the segments into the following categories: (1) pipeline segments that are 1,000 feet or less in length; (2) pipeline segments greater than 1,000 feet in length that can be removed from service for pressure testing; and (3) pipeline segments greater than 1,000 feet in length that cannot be removed from service for pressure testing without significantly impacting customers. These pipeline categories are then further analyzed to identify other factors that may impact a determination of whether to pressure test or replace the segment. These steps are depicted in the Replacement Decision Tree, depicted as Figure RDP-3 below.[26] The Phase 2A Replacement Decision Tree reflects the same principles adopted in D.14-06-007 for Phase 1.[27, 28]

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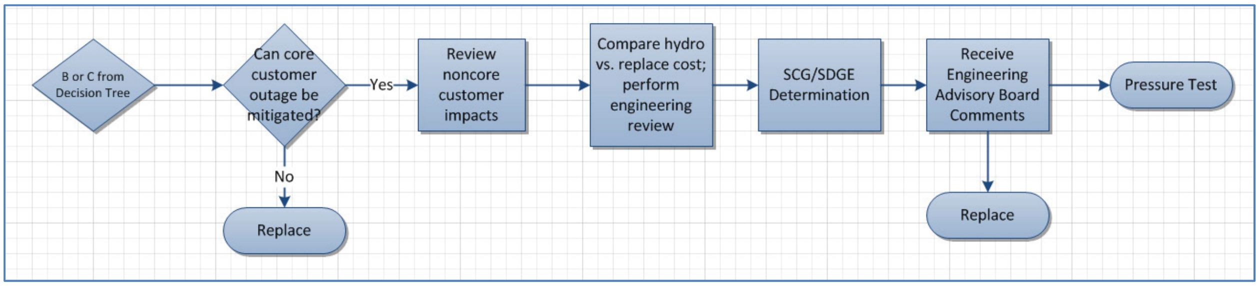
[26] As presented in A.11-11-002 (Rebuttal Testimony of Rick Phillips) at 8.
[27] *Supra* note 10.
[28] In rebuttal testimony (and as seen in the Replacement Decision Tree), SoCalGas and SDG&E proposed the formation of an Engineering Advisory Board to provide an extra level of comfort that SoCalGas and

Figure RDP-3
Southern California Gas Company
Replacement Decision Tree



The Phase 2A Decision Tree analysis is based on certain principles used to guide the test-versus-replace decision: (1) SoCalGas and SDG&E will not interrupt service to their core customers in order to pressure test a pipeline; (2) SoCalGas and SDG&E will work with noncore customers to determine if an extended outage is possible; (3) SoCalGas and SDG&E will, where necessary, temporarily interrupt noncore customers as provided for in their tariffs; (4) SoCalGas and SDG&E will work with noncore customers to plan, where possible, service interruptions during scheduled maintenance, down time or off-peak seasons; and (5) SoCalGas and SDG&E will consider cost and engineering factors along with the improvement of the pipeline asset. These principles were explained in SoCalGas and SDG&E's amended PSEP and during evidentiary hearings in A.11-11-002. It is important to note that no industry-wide standard exists that balances the risk of a pipeline failure with the cost of testing or replacing. Because of the need to apply engineering expertise and consider how the pipelines operate within the overall pipeline system, pipeline operators make this determination on a project-by-project basis.

a. Segments Less Than 1,000 Feet

Generally, pipeline segments that are less than 1,000 feet in length are identified for replacement under the Phase 2A Decision Tree. As described in the original PSEP application, it usually is more cost-effective to replace these short segments. SoCalGas and SDG&E may,

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SDG&E decisions were sound (A.11-11-002: Rebuttal Testimony of Rick Phillips at 14). The Engineering Advisory Board was to be a four-member board made up of a company representative, a representative of the Commission's Safety and Enforcement Division, a representative of the Commission's Energy Division, and an outside pipeline integrity expert to be mutually agreed upon by the first three (A.11-11-002: Rebuttal Testimony of Rick Phillips at 15). D.14-06-007, however, did not adopt the advisory board concept proposed by SoCalGas and SDG&E. *Id.* at 28.

however, engage in further review during the early planning stage to determine the most appropriate action for a specific segment. For example, costs and other engineering factors may be considered, depending on the unique attributes of each pipeline segment and its situation (e.g., the short segment is located on a bridge or under a freeway, making it impractical to replace due to heightened complexity). This approach was endorsed by the Commission in D.14-06-07 where, in denying SoCalGas and SDG&E's proposal to create an Engineering Advisory Board, the Commission determined it "see[s] no benefit to creating any oversight or advisory board to muddle the clear line of responsibility that rests solely with SDG&E and SoCalGas to competently manage and maintain the pipeline system."[29]

An important additional consideration is that installing new pipe—manufactured to modern standards—further enhances the safety of the entire pipeline system.

Line 2000–Cactus City Station, described in Section IX of my testimony, is an example of a replacement project in this Application that is less than 1,000 feet in length.

b. Segments Greater than 1,000 Feet

The decision to pressure test or replace pipeline segments greater than 1,000 feet is based on an assessment of potential customer impacts and an engineering and cost analysis that seeks to minimize customer impacts while maximizing safety and cost-effectiveness. Per the Decision Tree, pipeline segments greater than 1,000 feet that can be removed from service are generally pressure tested unless the segment was installed prior to 1946 and is non-piggable, or other factors indicate replacement should occur. Also per the Decision Tree, pipeline segments that are greater than 1,000 feet in length that cannot be removed from service are replaced.

As previously indicated, given that Phase 2A is located in less populated areas with a relatively smaller occurrence of customer impacts, it is estimated that the vast majority of Phase 2A pipelines will be pressure tested rather than replaced. With respect to the Phase 2A projects included in this Application, approximately 200 miles will be pressure tested and 1,900 feet will be replaced.

2. Consideration of Alternatives to Replacement

Phase 1B includes approximately 35 additional miles of pipeline that currently are under evaluation for descoping. These miles do not pertain to projects included in this Application and

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[29] D.14-06-007 at 28.

will be addressed in future proceedings based on the results of the analysis. SoCalGas and SDG&E have significantly reduced PSEP scope, including the number of miles to be replaced, through a thorough analysis during Stage 1 (Project Initiation) of the Seven Stage Review Process. To date, this due diligence has reduced PSEP scope by approximately 270 miles. In Phase 1B alone, SoCalGas and SDG&E have removed approximately 38 miles from the scope of PSEP, avoiding approximately $250 million in replacement costs, to the benefit of ratepayers. This reduction in Phase 1B scope has been accomplished through further records review for scope validation, reductions in MAOP, and abandonment of lines where feasible from an overall gas operating system perspective. Phase 1B lines are only abandoned after a thorough review of the ability of adjoining lines to meet current and future load requirements and verification that there are no anticipated customer impacts or system constraints.

In the event Phase 1B pipe remains in scope after project initiation, additional validation steps are taken by the project team to ensure the replacement can be accomplished in a cost-effective manner for ratepayers. For example, SoCalGas analyzes whether the existing pipe diameter should be used for the replacement pipe or if a smaller diameter can be utilized, which can result in savings on material and construction costs. Additionally, on a case-by-case basis for segments that have a record of a pressure test and have records that demonstrate the presence of seamless pipe, alternatives to replacement such as direct assessment, including various Non-Destructive Examination (NDE) methods, are considered. NDE refers to a technique whereby radiographical or ultrasonic methods for direct assessment are utilized to evaluate a pipeline without causing damage. It provides an equivalent means to validate the strength of a pipeline segment in a more cost-effective manner than replacement.

D. Scope of Phase 2B

Approximately 1,200 miles of pipelines in the SoCalGas transmission system have documentation of a pressure test that predates the adoption of federal pressure testing regulations—Part 192, Subpart J of Title 49 of the Code of Federal Regulations (CFR)—on November 12, 1970. The scope of Phase 2B is comprised of these pipelines, and in Section XXIII below, SoCalGas requests clarification of the Commission's guidance regarding these pipelines. There are no "standalone" Phase 2B projects presented for review in this Application.

E. Accelerated and Incidental Mileage

The Commission directed the utilities to develop plans that "provide for testing or replacing all [segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test] *as soon as practicable*" (emphasis added)[30] and that address "all natural gas transmission pipeline…even low priority segments,"[31] while also "[o]btaining the greatest amount of safety value, i.e., reducing safety risk, for ratepayer expenditures."[32] The inclusion of "accelerated" and "incidental" miles, defined below, is driven by efforts to achieve these goals while also adhering to the objective of minimizing customer impacts.

Accelerated miles are miles that otherwise would be addressed in a later phase of PSEP under the Decision Tree prioritization process but are advanced to realize operating and cost efficiencies. For the projects included in this Application: Phase 1B projects may include miles accelerated from Phase 2B; and Phase 2A projects may include miles accelerated from Phase 2B. Phase 2B miles are proposed to be accelerated only where they improve cost and program efficiency, address implementation constraints, or facilitate the continuity of testing.

Incidental miles are those which are not required to be addressed as part of PSEP, but are included where it is determined that doing so improves cost and program efficiency, addresses implementation constraints, or facilitates continuity of testing.[33]

Both incidental and accelerated miles are included (1) to minimize customer impacts, (2) in response to operational constraints, or (3) because of the cost and operational efficiencies gained by incorporating them into the project scope rather than executing a project circumventing them.[34]

F. Scope of the Valve Enhancement Plan

In D.11-06-017, the Commission also directed pipeline operators to address the installation of "automated or remote controlled shut-off valves" in their proposed

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30 *Supra* note 11.
31 *Supra* note 12.
32 *Supra* note 13.
33 An additional benefit of including incidental mileage is to further confirm the integrity of the pipeline.
34 Incidental and accelerated miles may be included in a pressure test or replacement project but are significantly more likely to occur with a pressure test project because of the efficiencies realized by pressure testing longer segments of pipeline.

implementation plans.[35] In response to this directive, SoCalGas and SDG&E submitted a Valve Enhancement Plan as part of their PSEP. The Valve Enhancement Plan works in concert with PSEP's pipeline testing and replacement plan to enhance system safety by augmenting existing valve infrastructure to accelerate SoCalGas and SDG&E's ability to identify, isolate and contain escaping gas in the event of a pipeline rupture.

The Valve Enhancement Plan focuses on the enhancement of valve infrastructure to isolate transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs. To maximize the cost effectiveness of this investment in valve infrastructure, SoCalGas and SDG&E's Valve Enhancement Plan enhances public safety through:

- Installation of Automatic Shutoff Valve (ASV)/Remote Control Valve (RCV) capability at intervals of approximately eight miles or less on pipelines that are twenty inches or greater in diameter;
- Installation of ASV/RCV capability at intervals of approximately eight miles or less on pipelines twelve inches or greater in diameter that operate at a hoop stress of 30% or more of SMYS; and
- Installation of ASV/RCV capability at shorter interval spacing (1/2 to one mile) on up to twenty pipeline segments that meet the above criteria and also cross a known geologic threat (*e.g.*, earthquake faults, landslide areas, washout areas and other potential geologic or man-made hazards).

SoCalGas anticipates completing construction for all remaining projects in the Valve Enhancement Plan in 2021. This Application includes valve projects projected to begin and complete construction in years 2019 through 2021. Consistent with the PSEP regulatory framework described in Section II.A above, valve projects in construction prior to December 31, 2018 are to be included for cost recovery in either SoCalGas and SDG&E's 2018 Reasonableness Review Application or a subsequent GRC.

G. Continued Prudent Implementation of PSEP

PSEP is the largest natural gas infrastructure enhancement program in SoCalGas and SDG&E history. As of June 2017, SoCalGas and SDG&E have completed 81 replacement miles

[35] D.11-06-017 at 21, 30 (Conclusion of Law Paragraph 9), and 32 (Ordering Paragraph 80).

and 90 pressure test miles in furtherance of PSEP. SoCalGas and SDG&E will continue to execute the PSEP consistent with their objectives to: (1) enhance public safety; (2) comply with Commission directives; (3) minimize customer impacts; and (4) maximize the cost-effectiveness of safety investments. PSEP has provided and will continue to provide value to customers for decades to come.

Projects will continue to be governed by the same policies and procedures currently in place to safely and efficiently implement the PSEP in compliance with the Commission's directives, with oversight provided by the PSEP Program Management Office (PMO). SoCalGas will continue to implement a Seven Stage Review Process to promote efficient PSEP project execution and prudent project management. The Seven Stage Review Process sequences and schedules PSEP project workflow deliverables as follows: (Stage One) Project Initiation; (Stage Two) Test or Replace Analysis; (Stage Three) Begin Detailed Planning; (Stage Four) Detailed Design/Procurement; (Stage Five) Construction; (Stage Six) Place into Service; and (Stage Seven) Closeout. Each stage includes specific objectives and an evaluation "gate" at the end of each stage to verify that objectives have been met before proceeding to the next stage. The projects included in this Application currently are in Stage Three.

Once approved to proceed, SoCalGas will remain committed to its objective to minimize costs for customers. SoCalGas will utilize its Performance Partner Program or other competitive sourcing methods to select construction contractors, and similarly employ competitive sourcing strategies to procure materials and other services, as described further in A.16-09-005. These proactive measures will continue to maximize the value of ratepayers' investments.

Prudent community outreach efforts will continue to keep customers, elected officials, and government entities informed about projects taking place in their communities. Additionally, environmental considerations will be effectively managed.

PSEP projects will continue to be executed in a manner that maintains reliable service to core customers. Where commercial and industrial customers may be impacted, SoCalGas and SDG&E develop execution strategies designed to minimize the impacts of planned outages and proactively communicate with potentially impacted customers to further mitigate those impacts. The forecasted PSEP costs in this GRC Application reflect SoCalGas' commitment to comply with Commission directives in a safe, efficient, and prudent manner.

IV. SUMMARY OF COSTS RELATED TO FUELING OUR FUTURE

Efficiencies related to identified Fueling our Future Group 6, SoCalGas Engineering and System Integrity pertaining to PSEP, have been factored into the zero-based project cost estimates contained in my testimony based on improved project efficiencies related to project execution. Additional information on Fueling our Future can be found in the revised joint testimony of Hal Snyder / Randall Clark (Ex. SCG-03-R/SDG&E-03-R).

V. SUMMARY OF ALISO RELATED COSTS

In compliance with D.16-06-054,[36] the testimony of witness Andrew Steinberg (Ex. SCG-12) describes the process undertaken so the TY 2019 forecasts do not include the additional costs from the Aliso Canyon Storage Facility gas leak incident (Aliso Incident), and demonstrates that the itemized recorded costs are removed from the historical information used by the impacted GRC witnesses.

As a result of removing historical costs related to the Aliso Incident from PSEP adjusted recorded data, and in tandem with the "zero-based" forecasting method employed for PSEP and described herein, additional costs of the Aliso Incident response are not included as a component of my TY 2019 funding request. PSEP costs that are related to the Aliso Incident are removed as adjustments in my workpapers (Ex-SCG-15-WP) and also identified in Table RDP-4 below.

Table RDP-4
Southern California Gas Company
PSEP Historical Adjustments to Remove Aliso Incident Costs
(Direct Costs – Thousands)

PIPELINE SAFETY ENHANCEMENT PLAN			
Workpaper	**2015 Adjustment (000s)**	**2016 Adjustment (000s)**	**Total (000s)**
2PS000.000, PIPELINE SAFETY ENHANCEMENT PROGRAM	0	-147	-147
2PS000.001, PIPELINE SAFETY ENHANCEMENT PROGRAM-PMO Costs	0	-10	-10

[36] D.16-06-054, mimeo., at 332 (ordering Paragraph 12) and 324 (Conclusion of Law 75).

Total Non-Shared	**0**	**-157**	**-157**
Total Shared Services	**0**	**0**	**0**
Total O&M	**0**	**-157**	**-157**

VI. RISK ASSESSMENT MITIGATION PHASE AND SAFETY CULTURE

A. Risk Assessment Mitigation Phase

All of my requested funds are linked to mitigating a top safety risk that has been identified in the RAMP Report[37]. This top risk was identified through the RAMP process described in the RAMP Report and is associated with activities sponsored in my testimony. The risk associated with PSEP is summarized in the table below:

Table RDP-5
Southern California Gas Company
RAMP Risk Chapter Description

RAMP Risk	Description
SCG-4 Catastrophic Damage Involving High-Pressure Pipeline Failure	This risk relates to the potential public safety and property impacts that may result from the failure of high-pressure pipelines (greater than 60 psi).

[37] I.16-10-015/I.16-10-016 Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company, November 30, 2016. Please also refer to Exhibit SCG-02-R/SDG&E-02-R, Chapter 1 (Diana Day) for more details regarding the utilities' RAMP Report.

TABLE RDP-6
Southern California Gas Company
RAMP Risk Summary of Capital Costs[38]
(Direct Costs – Thousands)

PIPELINE SAFETY ENHANCEMENT PLAN (In 2016 $)			
SCG-4 Catastrophic Damage Involving High-Pressure Pipeline Failure	**2017**	**2018**	**2019**
00569A.003, RAMP - Base - Line 36-9-09N (sec 12) Replacement	0	0	9,122
00569A.006, RAMP - Base - Allowance for Pipeline Test Failure	0	0	2,057
00569B.001, RAMP - Base - PSEP VALVE PROJECT BUNDLE 2019	4,920	8,200	68,880
00569C.001, RAMP - Base - VMS Project	667	667	666
00569C.002, RAMP - Base - PSEP PMO Costs	0	0	9,202
Total	**5,587**	**8,867**	**89,927**

TABLE RDP-7
Southern California Gas Company
RAMP Risk Summary of O&M Costs[39]
(Direct Costs – Thousands)

PIPELINE SAFETY ENHANCEMENT PLAN (In 2016 $)			
Categories of Management	**2016 Adjusted-Recorded**	**TY2019**	**Change**
PSEP Pipeline Hydrotest Projects	4,368	79,212	74,844
PMO Costs	588	3,944	3,356
Total Non-Shared Services	**4,956**	**83,156**	**78,200**

As directed by the Commission, the SoCalGas and SDG&E PSEP includes a risk-based prioritization methodology that prioritizes pipelines located in more populated areas ahead of pipelines located in less populated areas and further prioritizes pipelines operated at higher stress levels above those operated at lower stress levels. This prioritization directive and the goals to

[38] GRC PSEP costs only.
[39] GRC PSEP costs only.

enhance public safety, comply with Commission directives, minimize customer impacts, and maximize the cost effectiveness of safety investments have led to the development of the PSEP mitigation described in the RAMP.

My testimony proposes risk mitigation of the above identified RAMP risk through the activities described in Section III above and described in more detail in Sections VII, VIII, and IX. These projects include various pressure test and replacement projects as well as the continuation of the Valve Enhancement Plan.

Starting with the first PSEP project successfully completed in April 2013, SoCalGas and SDG&E have worked continuously to enhance the safety of their integrated natural gas transmission system. As PSEP segues into the GRC, SoCalGas remains committed to implementing PSEP as soon as practicable, and the number of projects forecasted for completion during the GRC timeframe reflect this commitment.

The continuing execution of PSEP directly contributes to mitigating this identified risk through the pressure testing of existing pipe and the installation of new pipe, manufactured and installed consistent with modern standards for safety, all of which enhance the safety of the SoCalGas and SDG&E transmission pipeline system for the benefit of our customers.

In developing the scope of the PSEP projects presented in the RAMP and the GRC, SoCalGas and SDG&E considered increasing the pace of PSEP-related work. While mindful of the Commission's desire that PSEP work be completed as soon as practicable, it was determined that the proposed pace of PSEP work accomplishes this objective while minimizing customer impacts that could occur if the pace of work was increased.

B. Safety Culture

A safety culture is actively compliant with regulations, designs and implements an approach to identify risks, and creates plans to mitigate those risks to improve safety for the public and employees. In these ways, PSEP is an integral part of the safety culture at SoCalGas. As stated earlier in my testimony, the primary objective of PSEP is to: (1) enhance public safety; (2) comply with Commission directives; (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments. As directed by the Commission, the SoCalGas and SDG&E PSEP includes a risk-based prioritization methodology that prioritizes pipelines based on several factors. Mitigation plans are developed and proposed based on the results of the risk identification and prioritization process.

PSEP embodies the safety culture that is present at SoCalGas and SDG&E, and both utilities value the outstanding safety record associated with PSEP projects. PSEP's Occupational and Safety Health Administration (OSHA) incident rate of .47 is well below the national average incident rate of .81 in the oil and gas pipeline construction industry.[40]

As the largest natural gas infrastructure project in SoCalGas and SDG&E history, PSEP continues to be an example of our safety culture and to be successfully executed in compliance with Commission orders, California Public Utilities Code Section 958, and our ongoing commitment to employee and public safety. From the replacement of decades-old, non-piggable pipe to implementation of the Valve Enhancement Plan to allow for the remote isolation and depressurization of the transmission pipeline system in 30 minutes or less in the event of a pipeline rupture, the elements of PSEP reflect SoCalGas' safety culture.

VII. PRESSURE TEST PROJECTS

Table RDP-8
Southern California Gas Company
Non-Shared O&M Cost Summary
(Direct Costs – Thousands)

Cost Category	O&M	Capital	Total
PSEP Pressure Test Projects	$236,379	$64,443	$300,822

A. Introduction

1. Description

This section provides an overview of eleven pressure test projects[41] presented for review in this Application as part of the ongoing implementation and execution of PSEP. Table RDP-9 depicts the PSEP pressure test projects[42] currently planned to be executed during the three-year

[40] United States Department of Labor, Bureau of Labor Statistics, Report SNR05, Injury, Illness, and Fatalities, Page 4.
[41] There is a capital cost component to each pressure test project, as described in the individual project descriptions. To facilitate a better understanding of the entire scope of these projects, both capital and O&M costs, and the associated scopes of work, are presented in this section.
[42] Pressure test projects are considered Expense, although there are some components that are capitalized in accordance with applicable accounting guidelines.

rate case cycle. More detailed information regarding each project is contained in supplemental workpapers (Ex. SCG-15-WP).

Table RDP-9
Southern California Gas Company
GRC Pressure Test Projects
(Direct Costs – Thousands)

Project	Phase	O&M	Capital	Total
235 West Section 1	2A	$41,662	$12,106	$53,768
235 West Section 2	2A	$25,679	$11,181	$36,860
235 West Section 3	2A	$14,119	$3,370	$17,489
407	2A	$4,188	$962	$5,150
1011	2A	$4,421	$746	$5,167
2000 Chino Hills	2A	$33,964	$11,371	$45,335
2000 Section E	2A	$13,955	$1,565	$15,520
2000 Blythe to Cactus City Hydrotest	2A	$39,937	$11,908	$51,845
2001 W Section C	2A	$22,868	$3,361	$26,229
2001 W Section D	2A	$24,404	$4,873	$29,277
2001 W Section E	2A	$11,182	$3,000	$14,182
Total Pressure Test Costs		**$236,379**	**$64,443**	**$300,822**

Because 2019 will be a transition year as PSEP is incorporated into the GRC process, forecasted costs for 2019 do not reflect the level of forecasted spend in the post-test years. Therefore, the PSEP TY 2019 O&M forecast has been normalized to reflect the forecasted total level of O&M expenditures over the 2019 – 2021 GRC period. SoCalGas will seek amortization of planning and engineering costs associated with Phase 2A projects included in this Application and recorded in the Pipeline Safety Enhancement Plan – Phase 2 Memorandum Account (PSEP-P2MA) in a future proceeding, as authorized under D.16-08-003.[43] Additional planning and engineering costs for certain projects will continue to be incurred so that construction can begin in a timely manner upon Commission approval in this Application to proceed with the projects. Although my testimony supports all project costs (including the aforementioned planning and engineering costs), because SoCalGas anticipates a portion of the costs of executing these projects will be incurred prior to the Test Year, that portion is not reflected in the requested

[43] D.16-08-003 at 14 (Ordering Paragraph 1).

revenue requirement. SoCalGas will request amortization of these costs in the 2018. Reasonableness Review, along with the design and planning costs recorded in the PSEP-P2MA.

SoCalGas requests authorization to continue to record and balance PSEP costs in a two-way balancing account, the Pipeline Safety Enhancement Plan Balancing Account (PSEPBA), as described in the Regulatory Accounts testimony of Rae Marie Yu (Exhibit SCG-42). A minimum of three years will lapse between the completion of the detailed project cost estimates included in this filing and the start of construction. During this three-year period, construction, contractor, and material costs may change, new environmental regulations may be enacted, and other external forces may come into play that may impact what today is a reasonable project cost estimate. Additionally, a forecast of costs is just that—a forecast—and despite the rigor employed to provide as detailed and well thought-out cost estimates as possible, deviations from the estimates can and should be expected occur.

SoCalGas forecasts $898,793,695 on an aggregate basis for the ongoing implementation of PSEP, recognizing that actual costs will be different (both higher and lower than the forecasts) and thus, from a total costs standpoint, will tend to offset. SoCalGas requests authority to substitute other PSEP projects in the event of unanticipated project delays or if higher priority pipe segments are identified while managing to the authorized revenue requirement that would be subject to the proposed PSEP balancing account mechanism as described in the testimony of Rae Marie Yu (Exhibit SCG-42). Therefore, the forecasted amount should be viewed in aggregate and not on a project-by-project basis.

The projects listed above are expected to be completed in the three-year GRC cycle. In the event the Commission grants SoCalGas' request to add a fourth year to the GRC cycle, Section X of my testimony presents for review pressure test and replacement projects that would be executed during the fourth year.

2. Forecast Method[44]

The forecast method utilized for this cost category is zero-based. This method is most appropriate because each PSEP project is unique in scope, size, and complexity. A project-

[44] The forecast method described is applicable to both pressure test (primarily O&M but with a capital component as described in testimony) and replacement (capital) projects. *See* Section IV.2. for a description of the forecast methodology for valve projects and miscellaneous PSEP capital forecasts.

specific cost estimate was developed for each pipeline project, based on detailed engineering and project planning analyses, as described below.

The estimating process used to develop cost estimates for PSEP projects has evolved over time. In 2011, SoCalGas and SDG&E retained a third-party consultant to help develop an initial PSEP project cost estimating tool in response to the Commission's June 2011 directive to all California pipeline operators to file proposed pressure testing implementation plans in August 2011 that "include best available expense and capital cost projections for each Plan component."[45] In 2013, SoCalGas and SDG&E enhanced the tool to increase the number of factors considered in deriving estimates, which enabled the utilities to prepare more comprehensive estimates. Since 2013, SoCalGas and SDG&E have continued to enhance estimate accuracy by incorporating actual costs as they are incurred in the field. SoCalGas and SDG&E have also formed a dedicated estimating department to increase focus on the quality and accuracy of estimates. These continuous improvement enhancements have resulted in a more robust tool and process that incorporates the input of subject matter experts in the functional areas described below. These subject matter experts use their respective expertise and professional experience to provide estimate assumptions for their areas that form the basis of each estimate. Notwithstanding the foregoing improvements and level of rigor, estimates remain estimates, and each PSEP project is unique. As such, SoCalGas expects both foreseeable and unforseeable conditions to be encountered during construction that may result in actual expenditures varying from estimates.

a. Planning and Engineering Design

For the purpose of developing the pressure test estimates in this Application, SoCalGas and SDG&E undertook the following work:

- Assessment and confirmation of project parameters;
- Site visits;
- Review of feature studies;[46]

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[45] D.11-06-017 at 32 (Ordering Paragraph 9).

[46] A feature study depicts and describes the physical components of a pipeline and the attributes associated with those components.

- Coordination with SoCalGas/SDG&E Gas Engineering and Pipeline Integrity groups to identify repairs/cut-outs for anomalies and in-line inspection compatibility;
- Development of a pipeline profile using ground elevation data;
- Determination of maximum and minimum allowable test pressures, and corresponding segmentation of the pipeline into test sections;
- Development of a preliminary design for each work site;
- Survey and preparation of base maps;
- Analysis of environmental restrictions to work locations;
- Analysis of seasonal restrictions; and
- Determination of additional valve locations, as required.

Costs associated with planning and engineering design work are incorporated into the project cost estimates in this Application, as indicated in the individual project workpapers. However, amortization of planning and engineering costs booked to the Pipeline Safety and Enhancement Plan – Phase 2 Memorandum Account (PSEP-P2MA) will be included in the 2018 Reasonableness Review as described in Section VII.A.I.

b. Development of the Project Cost Estimate

As part of the scope definition process described above, subject matter experts representing the following key areas contribute to the estimate development process.

c. Project Execution

Project Execution subject matter experts provide the following in support of estimate development:

- For replacement projects, analysis of alternatives to replacement (*e.g.*, abandonment, de-rating[47] the line, and non-destructive examination for short segments);
- Validation of appropriate replacement diameter;
- Identification of taps and laterals within pressure test or replacement segments;

[47] Reducing the MAOP of the line to less than 20% SMYS.

- Assessment of potential system and customer impacts and development of mitigation strategies;
- Identification of pipeline features to be cut out prior to a pressure test (*e.g.*, pipeline anomalies, non-piggable features, and obsolete appurtenances);
- Identification of potential valve additions;
- Review and approval of scope of work; and
- Review and approval of project-specific pressure test procedures, when applicable.

d. Engineering Design

The key responsibilities of Engineering Design is to perform the planning and engineering design work necessary to provide a scope of work with sufficient detail to develop more robust project cost estimates. The scope of work is intended to facilitate the proximation of all identifiable cost components up to, and including, the completion of construction and close-out. The typical planning and engineering design scope includes the following considerations:[48]

- Assessment and validation of project extent/parameters;
- Physical visit to job site to gain familiarity with the area;
- Development of preliminary design for each work site;
- Development of pipeline profile;
- Identification of pressure test segments based on the minimum and maximum allowable test pressures in order to achieve required test pressures; and
- Identification of any special pipeline crossings for replacement projects (*e.g.*, waterways, railroads, freeways, etc.).

e. Environmental

Environmental subject matter experts provide the following in support of estimate development:

- Detailed analysis of recommended project routing to minimize environmental construction impacts and associated cost impacts;

[48] Some of these elements vary between replacement and pressure test projects.

- Identification of permit conditions and development of costs associated with securing required environmental permits and mitigation costs, where applicable;
- Determination of water treatment costs, as applicable;
- Quantification of water transportation costs, as appropriate; and
- Development of cost estimates for required environmental construction monitoring, sampling/laboratory analysis, abatement, and hazardous material management and disposal.

f. Construction

The forecast of construction costs incorporates input from SoCalGas and SDG&E subject matter experts and impacted organizations including the following elements:

- Input from contractors with construction expertise;
- Field walk with all parties to capitalize on combined expertise for assessment of constructability issues; and
- Review of engineering design package to determine construction assumptions.

g. Land Services

Land Services provides the following in support of estimate development:

- Determination of applicable municipal permit requirements and associated costs;
- Identification of potential laydown/staging yards required for individual projects, and subsequent communication with land owners as required to determine availability; and
- Development of cost estimates associated with laydown yards, temporary construction easements, grants of easement, appraisals, title reports, etc.

h. Compressed Natural Gas/Liquefied Natural Gas (CNG/LNG) Team

The CNG/LNG Team provides the following in support of estimate development:

- Provision of analyses on impacted customer natural gas loads to determine optimal process for keeping customers online; and
- Development of cost estimates for the provision of CNG/LNG

i. Supply Management

To assist in developing cost estimates, Supply Management provides material and logistics-related cost estimates based on a preliminary bill of material developed by the Project Team.

j. Estimating

Upon receipt of input from the above subject matter experts, a comprehensive estimate is developed incorporating the various teams' analyses. The estimating team works with the subject matter experts to identify potential risks and their potential for occurrence. The results are factored into the project cost estimate.

3. Disallowed Costs

D.14-06-007 (as modified by D.15-12-020) disallowed costs associated with post-1955 pipe without sufficient record of a pressure test. Table RDP-10 below reflects forecasted disallowed costs for pressure test projects included in this Application that contain post-1955 pipeline. These forecasted disallowed costs have been removed from the total project forecasted cost.

Table RDP-10
Southern California Gas Company
Disallowed Post-55 PSEP Forecasted Costs
(Direct Costs – Thousands)

Project	O&M
235 West Section 1	$9
235 West Section 2	$4
Total	**$13**

4. Cost Drivers

The cost drivers behind this forecast are the ongoing implementation and execution of PSEP, to comply with Commission directives and statutory law.

5. Pressure Test Project Descriptions

Table RDP-11
Southern California Gas Company
Line 235 West Section 1
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
235 West Section 1	San Bernardino County	24.6 miles	$41,662	$12,106	$53,768

The Line 235 West Section 1 project will pressure test approximately 24.6 miles of pipe in San Bernardino County west of Newberry Springs and is located in areas regulated by the Bureau of Land Management and State Lands Commission. The scope of the project includes 47 test sections of varying length to address elevation changes totaling approximately 2,600 feet over the 24.6 miles. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this test include the remediation/replacement of 16 identified anomalies. As explained in the testimony supporting SoCalGas and SDG&E's PSEP, "[b]y mitigating potential sources of pressure test failures before conducting the pressure test, planners can avoid the pitfalls associated with entering into a cycle of pressure test failures."[49] Removal of identified anomalies prior to pressure testing enhances the likelihood of a successful pressure test, thereby reducing both the time and costs of pressure testing.

The capital costs associated with this test also include the replacement of 48 short sections of pipe totaling approximately 2,700 feet to facilitate hydrotesting. As part of the normal pressure testing process, a section of the existing pipeline is removed to accommodate the temporary test heads that are used to conduct the hydrostatic testing. After the line is tested and the temporary test heads are removed, a new section of pipe is installed in place to "tie-in" the pressure tested segment to the pipeline on either side of the segment. The tie-in segment is new pipe and, as such, is capitalized.

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[49] August 26, 2011, Testimony of Douglas M. Schneider in support of SoCalGas and SDG&E's Pipeline Safety Enhancement Plan, *as amended* December 5, 2011, at 57 (Exhibit SCG-04 in A.11-11-002).

Table RDP-12
Southern California Gas Company
Line 235 West Section 2
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
235 West Section 2	San Bernardino County	20.3 miles	$25,679	$11,181	$36,860

The Line 235 West Section 2 project will pressure test approximately 20.3 miles of pipe in San Bernardino County between Sawtooth Canyon and the Mojave River. The anticipated scope includes 27 test sections of varying length to address elevation changes totaling approximately 1,400 feet over the 20.3 miles. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this test include the remediation/replacement of four identified pipeline anomalies and the replacement of 28 short sections of pipe totaling approximately 1,500 feet to facilitate the hydrotesting procedure.

Table RDP-13
Southern California Gas Company
Line 235 West Section 3
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
235 West Section 3	San Bernardino County	26.9 miles	$14,119	$3,370	$17,489

The Line 235 West Section 3 project will pressure test approximately 26.9 miles of pipe in San Bernardino and Los Angeles Counties between Adelanto and Littlerock. The scope of the project includes six test sections of varying length to address elevation changes totaling approximately 300 feet over the 26.9 miles. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this test include the replacement of 91 feet of pipe to allow for placement of a test head outside of a regulation station and the replacement of six short sections of pipe totaling 132 feet to facilitate hydrotesting.

Table RDP-14
Southern California Gas Company
Line 407
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
407	Santa Monica Mountains	4.0 miles	$4,188	$962	$5,150

The Line 407 project will pressure test approximately four miles of pipe in the Santa Monica Mountains and residential neighborhoods between Tarzana and West Los Angeles. The scope of the project includes two test sections to address elevation changes. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections. The capital costs associated with this test include the replacement of three short sections of pipe totaling 69 feet to facilitate hydrotesting.

Table RDP-15
Southern California Gas Company
Line 1011
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
1011	Ventura County	1.8 miles	$4,421	$746	$5,167

The Line 1011 project will pressure test approximately 1.8 miles of pipe in the hills above the city of Ventura. The scope of the project includes two test sections to address the existence of an aboveground span. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this project include replacement of four short sections of pipe and eleven un-piggable bends, totaling approximately 1,500 feet, to facilitate hydrotesting and accommodate assessment of the pipeline using in-line inspection tools.

Table RDP-16
Southern California Gas Company
Line 2000 Chino Hills
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
2000 Chino Hills	Orange/Riverside County	10.0 miles	$33,964	$11,371	$45,335

The Line 2000 Chino Hills project will pressure test approximately ten miles of pipe in Orange and Riverside Counties in the Chino Hills State Park.[50] The scope of the project includes 34 test sections of varying length to address environmental considerations, pipeline accessibility issues and extreme elevation changes, totaling approximately 1,100 feet over the ten miles. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this test include replacement of six taps, 38 short sections of pipe, and remediation/replacement of four anomalies, totaling 2,180 feet, to facilitate hydrotesting.

Table RDP-17
Southern California Gas Company
Line 2000 Section E
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
2000 Section E	Riverside County	8.9 miles	$13,955	$1,565	$15,520

The Line 2000 Section E project will pressure test approximately nine miles of pipe in Riverside County east of Indio.[51] The project scope includes five test sections of varying length to address environmental considerations and elevation changes totaling 700 feet over the nine miles. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

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[50] Line 2000 is a 118-mile line that extends from the Arizona border to Los Angeles. Sections C, D, and E are part of several Line 2000 PSEP projects: Section A (included in A.14-12-016), 2000 West Sections 1-3 (included in A.16-09-005), Sections C and D (included in A.17-03-021), and Section E and East of Cactus City (included in this Application).
[51] *Supra* note 50.

The capital costs associated with this project include replacement of six short sections of pipe and a section of pipe underneath a freeway totaling 640 feet to facilitate hydrotesting.

Table RDP-18
Southern California Gas Company
Line 2000 Blythe to Cactus City Hydrotest
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
2000 Blythe to Cactus City Hydrotest	Riverside County	64.7 miles	$39,937	$11,908	$51,845

The Line 2000 Blythe to Cactus City Hydrotest project will pressure test approximately 65 miles of pipe in Eastern Riverside County between Whitewater and Cactus City. The scope of the project includes 32 test sections to address environmental considerations and elevation changes totaling approximately 1,400 feet over the 65 miles. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this project include the remediation of two anomalies, replacement of 14 taps, and replacement of 33 short sections of pipe totaling 1,900 feet to facilitate hydrotesting.

Table RDP-19
Southern California Gas Company
Line 2001 West Section C
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
2001 W Section C	Riverside County	13.9 miles	$22,868	$3,361	$26,229

The Line 2001 West Section C project will pressure test approximately 14 miles of pipe in Riverside County between Whitewater and Indio.[52] The project scope includes 13 test sections of varying length to address environmental considerations and elevation changes totaling

[52] Line 2001West is a 140-mile line that extends from Riverside County to Los Angeles County. Section C is part of several Line 2001 West PSEP projects: 2001 West A Sections 15,16 and 2001 West B Sections 10,11, 14 (included in A.16-09-005), 2000 West Sections 1-3 (included in A.16-09-005), Sections D and E (included in this Application), 2001 (to be included in the next General Rate Case).

approximately 1,000 feet. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this project include replacement of 16 short sections of pipe totaling 700 feet, four taps, and 251 feet of pipe east of Whitewater Station to facilitate hydrotesting.

Table RDP-20
Southern California Gas Company
Line 2001 West Section D
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
2001 W Section D	Riverside County	17.8 miles	$24,404	$4,873	$29,277

The Line 2001 West Section D project will pressure test approximately 18 miles of pipe in the Banning/Beaumont area of Riverside County. The project scope includes 16 test sections of varying length to address environmental considerations, accessibility issues due to the terrain, and elevation changes totaling approximately 1,300 feet over the 18-mile project length. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this project include replacement of one tap and twenty short sections of pipe totaling 820 feet to facilitate hydrotesting.

Table RDP-21
Southern California Gas Company
Line 2001 West Section E
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
2001 W Section E	Riverside County	8.9 miles	$11,182	$3,000	$14,182

The Line 2001 West Section E project will pressure test approximately nine miles of pipe in Riverside County east of Indio. The project scope includes five test sections of varying length to address environmental considerations and elevation changes totaling approximately 900 feet. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this project include replacement of six short sections of pipe totaling 300 feet to facilitate hydrotesting.

VIII. MISCELLANEOUS PSEP COSTS

Table RDP-22
Southern California Gas Company
Miscellaneous PSEP Cost Summary
(Direct Costs – Thousands)

Cost Category	O&M	Capital	Total
Allowance for Pipeline Failures	$0	$6,170	$6,170
Implementation Continuity Costs	$3,741	$1,857	$5,599
Program Management Office (PMO)	$11,831	$29,606	$41,438
Total Miscellaneous PSEP Costs[53]	**$15,573**	**$37,634**	**$53,206**

A. Allowance for Pipeline Failures

Table RDP-23
Southern California Gas Company
Allowance for Pipeline Failures
(Direct Costs – Thousands)

Allowance for Pipeline Failures	Capital
	$6,170

The test project forecasts described above do not include costs related to a test failure, as such an occurrence is expected to be infrequent. To date, SoCalGas and SDG&E have experienced one test failure out of a total of 53 separate tests totaling 90 miles. Costs associated with a test failure primarily consist of the replacement of the failed pipe segment and costs incurred to achieve water containment following the failure.

The forecasted costs are based on SoCalGas' PSEP experience of one test failure for approximately every 90 miles tested. Given this statistic, an allowance for three test failures for the three-year GRC period is included.

[53] Difference due to rounding.

B. Implementation Continuity Costs

Table RDP-24
Southern California Gas Company
Implementation Continuity Costs
(Direct Costs – Thousands)

Implementation Continuity Costs	O&M	Capital[54]	Total
	$3,741	$1,857	$5,599[55]

To begin timely construction on PSEP projects that will be completed after the TY 2019 GRC cycle and included in the next GRC,[56] activities such as environmental permitting and land acquisition must begin during the 2019 GRC period. These activities are incremental to those recorded to the Pipeline Safety Enhancement Plan Memorandum Account, which was established to record planning and engineering design costs to develop detailed project cost estimates.

Permitting agencies often require detailed design information for a project to assess permit conditions and requirements. Given the length of time and advance preparation required to obtain permits (which can be up to 36 months), waiting until Commission approval of the next GRC to commence this activity could result in projects not being completed in a timely manner. To continue to implement PSEP as soon as practicable, these types of planning and engineering activities must take place before the next GRC cycle. The forecasted amount presented here represents project design costs for approximately seven projects anticipated to be included in the next GRC following the TY 2019 GRC.

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[54] The forecasted design costs may be either O&M or Capital, depending on whether they relate to replacement (Capital) or pressure testing (O&M). Both forecasts are presented here and in the supplemental workpapers for clarity of presentation.
[55] Difference due to rounding.
[56] TY 2023 if the Commission approves a four-year term for the TY 2019 GRC as proposed in the Post Test Year Ratemaking testimony of Jawaad Malik (Exhibit SCG-44) or TY 2022 if the Commission approves a three-year term.

C. Program Management Office

Table RDP-25
Southern California Gas Company
Program Management Office
(Direct Costs – Thousands)

Program Management Office	O&M	Capital[57]	Total
	$11,831	$29,606	$41,438[58]

PSEP costs submitted for recovery in after-the-fact reasonableness reviews and projects included for pre-approval in the 2017 Forecast Application (A.17-03-021) are presented on a fully loaded basis, including applicable Company overheads. In addition to Company overheads, fully loaded costs include PSEP General Management and Administration (GMA) costs. GMA costs are costs incurred in support of PSEP that are not charged to individual projects. GMA accumulates costs from both the PSEP organization and from other Company departments supporting PSEP. Support costs from other Company departments are charged to a GMA internal order number to appropriately track and record time spent supporting PSEP. With the transition of PSEP to the GRC, such segregation will no longer be necessary and certain support costs from other Company departments will remain in their respective costs centers. Therefore, effective with this filing, GMA will no longer be a component of PSEP costs.[59]

Beginning in 2019, costs of the PSEP organization that are not charged directly to projects will be accumulated in the Program Management Office (PMO). The PMO provides oversight at the organizational level, helps develop PSEP policies to promote oversight and accountability, and develops reporting metrics to keep management apprised of PSEP progress. PSEP entities that charge exclusively to the PMO are the PSEP Senior Director, PMO staff, and Budget and Administration groups. Time for PSEP Construction and PSEP Project Execution personnel that is not charged directly to projects is also included in overall PMO costs. Examples of this include

[57] For the purposes of explaining all facets of the PMO in one section, both O&M and Capital forecasts are included here and in the supplemental workpapers.
[58] Difference due to rounding.
[59] Completed Phase 1A projects included for cost recovery through the reasonableness review process will continue to include a GMA component.

time for the development of project execution and construction processes, procedures, and training.

PSEP is a large and complex program that requires appropriate governance and management to achieve its goal of cost effectively enhancing safety. The PSEP governance and management strategy is to comply with applicable regulatory requirements, continuously improve, and establish proper controls and management across PSEP functional areas to verify that design, material procurement, construction, and closeout are performed correctly and consistently. The PMO ensures these objectives are met.

As acknowledged by the Safety and Enforcement Division (SED) (formerly known as the Consumer Protection and Safety Division) in a 2012 Technical Report on the SoCalGas and SDG&E PSEP, this oversight and management function is prudently placed with one central department: "CPSD believes the Companies are approaching the need to manage the PSEP in a reasonable manner and that the PMO will be critical to the proper execution of PSEP."[60] SED's assessment has proven to be true. The following are key PMO functions.

The PMO collaborates, coordinates, and provides functional guidance on project design and construction to cost effectively meet or exceed compliance requirements and follow, as appropriate, industry best practices. The PMO, and the governance and management structure, is designed to promote safety and efficiency by providing structure, guidance, and oversight. In addition to its safety focus, the PMO also oversees implementation, provides checks and balances during the project life cycle, and allows SoCalGas to assess whether projects are within budget, on schedule, and meet quality, customer impact, and compliance goals. PSEP financial reporting is managed by the PMO, including the coordination of budget development, budget forecasting, and budget variance reporting.

The PMO develops standards and procedures for the PSEP that enables PSEP to be executed in a consistent manner across projects. These standards and procedures, besides including PSEP-specific information to improve safety and efficiency, also incorporate SoCalGas' existing requirements for design, material acquisition, construction, construction inspection, documentation, and environmental compliance.

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[60] Technical Report of the Consumer Protection and Safety Division Regarding the Southern California Gas Company and San Diego Gas and Electric Company Pipeline Safety Enhancement Plan dated January 17, 2012, at 22.

The PMO develops reports and Key Performance Indicators (KPIs) at both the granular project level and the overall PSEP level. SoCalGas management, on a monthly basis, reviews the KPIs to monitor PSEP. Included in the KPIs are financial metrics, pressure testing and replacement progress metrics (e.g., number of projects that have entered construction and placed into service), valve metrics (e.g., number of valves that have entered construction and been placed into service), safety metrics, environmental compliance metrics, material availability metrics, Diverse Business Enterprise goals, and headcount. Qualitative data, including a summary of key accomplishments, constraints, and opportunities for improvement, is also reviewed by the PSEP PMO and SoCalGas management.

IX. CAPITAL

A. Introduction

The following provides an overview of the pipeline replacement projects, continuation of the Valve Enhancement Plan, and miscellaneous capital PSEP costs necessary for the successful implementation of PSEP. As previously stated, a description of the capital component of pressure test projects and future project design costs are included in the individual pressure test project descriptions presented in Section VII, as is a description of the costs associated with a pressure test failure. Table RDP-26 summarizes the total capital forecasts for 2019 through 2021.

Table RDP-26
Southern California Gas Company
Capital Expenditures Cost Summary[61]
(Direct Costs – Thousands)

Cost Category	Capital
Replacement Projects	$301,250
Valve Enhancement Plan	$246,000
Total PSEP Capital Costs	**$547,250**

[61] Table RDP-21 reflects those cost categories that are solely Capital in nature. Please see Sections VII and VIII for the capital component of pressure test and miscellaneous PSEP costs which are shown in tandem with applicable O&M costs to facilitate a better understanding of the entire scope of these cost categories.

The Phase 1B replacement projects, as indicated in Section III, are intended to replace non-piggable pipelines installed prior to 1946 with new pipe constructed using state-of-the-art methods and to modern standards, including current pressure test standards.

Continued work on the Valve Enhancement Plan entails enhancing system safety by installing and upgrading valve infrastructure to support automatic and remote isolation as well as depressurization of the transmission pipeline in 30 minutes or less in the event of a pipeline rupture.

1. Description

This section provides an overview of 11 replacement projects and Valve Enhancement Plan project bundles in the ongoing implementation and execution of PSEP as directed by the Commission and described in my introduction. Detailed information regarding each project is provided in the supplemental workpapers.

Table RDP-27 depicts the PSEP replacement projects currently planned to be executed in connection with this Application.

Table RDP-27
Southern California Gas Company
GRC Replacement Projects
(*Direct Costs – Thousands*)

Project	Phase	Capital
85 Elk Hills to Lake Station	1B	$88,906
36-9-09 North Section 12	1B	$9,813
36-9-09 North Section 14	1B	$19,980
36-9-09 North Section 15	1B	$14,193
36-9-09 North Section 16	1B	$18,036
36-1032 Section 11	1B	$8,692
36-1032 Section 12	1B	$26,601
36-1032 Section 13	1B	$17,811
36-1032 Section 14	1B	$13,937
44-1008 (50%)	1B	$76,582
2000-E Cactus City Compressor Station	2A	$6,698
Total Replacement Costs		**$301,250**[62]

To continue to execute PSEP in accordance with Commission directives and as productively as possible, SoCalGas requests authority to substitute the projects currently planned to be addressed with other PSEP projects in the event unanticipated project delays impact projects or if higher priority pipe segments are identified. To accommodate this request, the forecasted amount should be viewed in the aggregate and not on a project-by-project basis. It should be noted the projects listed above are those expected to be completed in the three-year GRC cycle. In the event the Commission grants SoCalGas' request to add a fourth year to the GRC cycle, the replacement projects that SoCalGas anticipates executing during the fourth year are presented in Section X of my testimony.

2. Forecast Method

The forecast method utilized for this cost category is zero-based. This method is most appropriate because each PSEP project is unique in scope, size, and complexity. See

[62] Difference of $1K due to rounding.

Section VIII.A for additional information regarding the forecast methodology and the process used to develop the detailed pipeline cost estimates which form the basis for each project forecast.

For the purpose of developing pipeline replacement estimates, SoCalGas undertook the following work:

- Assessment and confirmation of project parameters;
- Site visits to determine any potential relocation routes;
- Development of a preliminary design for Geographic Information System (GIS) alignment sheets showing required work area and pipeline location;
- Identification of any special crossings (*e.g.*, waterways, major highways, railroads);
- Survey and preparation of base maps;
- Analysis of environmental restrictions to work locations and seasonal restrictions;
- Identification of valve sites;
- Identification of access roads, where required; and
- Identification of workspaces, including potential material staging areas.

The following methodology was used to forecast costs for the Valve Enhancement Plan: first, unit costs for the various types of valve and related activities were developed based on PSEP actual costs for the various elements; then these unit costs were applied to the forecasted quantities for each type of installation. See the supplemental workpapers for additional detail.

For Program Management Office costs, a zero-based forecast methodology was used consistent with the other PSEP cost forecasts.

3. Disallowed Costs

D.14-06-007 (as modified by D.15-12-020) disallowed costs associated with the mileage associated with post-1955 pipe without sufficient record of a pressure test. Table RDP-28 below reflects forecasted disallowed costs for replacement projects included in this Application that contain post-1955 pipeline mileage. These forecasted disallowed costs have been removed from the total project forecasted cost.

Table RDP-28
Southern California Gas Company
Disallowed Post-1955 PSEP Forecasted Costs
(Direct Costs – Thousands)

Project	Capital
2000-E East Cactus City Station Replacement	$251
Total	**$251**

4. Cost Drivers

The cost drivers behind this forecast are activities associated with the ongoing implementation and execution of PSEP, in compliance with Commission decisions and statutory law.

5. Replacement Project Descriptions

Table RDP-29
Southern California Gas Company
Line 85 Elk Hills to Lake Station
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
85 Elk Hills to Lake Station	San Joaquin Valley	13.0 miles	$88,906

The Line 85 project will install approximately 13.0 miles of pipe between Elk Hills Road and Lake Station to replace pipe installed in 1931. The segment of Line 85 being replaced is the sole source of supply to several core and large non-core customers as well as the primary source of supply for multiple transmission and distribution systems serving the San Joaquin Valley and Central Coast. The new alignment will minimize the use of private property by prioritizing installation within public roadways. This will facilitate future operation and maintenance activities and improve safety and reliability as the potential for third-party damages will be reduced.

The installation method will be open trench, with the exception of approximately 2,400 feet that will be installed via horizontal directional drilling (HDD)[63] and approximately 1,000 feet that will be installed via conventional boring methods.

Table RDP-30
Southern California Gas Company
Line 36-9-09 North Section 12
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
36-9-09 North Section 12[64]	Santa Barbara County	0.9 miles	$9,813

The Line 36-9-09 North Section 12 project will install approximately 0.9 miles of pipe in San Luis Obispo County near Santa Margarita to replace pipe installed in 1920. Approximately half the replacement will require HDD, because this portion of the replacement will be underneath the Santa Margarita River, trees, and mountainous terrain. The existing pipe will be replaced with pipe of uniform diameter to accommodate assessment of Line 36-9-09 North using in-line inspection tools.

Table RDP-31
Southern California Gas Company
Line 36-9-09 North Section 14
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
36-9-09 North Section 14	Santa Barbara County	1.9 miles	$19,980

The Line 36-9-09 North Section 14 project will install approximately 1.9 miles of pipe in San Luis Obispo County to replace pipe installed in 1920. The majority of the pipe will be installed using the open trench method with the exception of approximately 600 feet underneath a stream to be installed using HDD methods and approximately 175 feet underneath a railroad

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[63] A trenchless method of installing underground pipe.
[64] Line 36-9-09 North is a 36-mile pipeline between San Luis Obispo and Santa Barbara Counties. The four sections included in this Application are part of 15 PSEP projects associated with this line that are managed separately due to the distance between the various sections. Once completed, the entire line will be of a uniform diameter to meet capacity requirements and to enable the use of in-line inspection tools.

crossing installed using the slick bore[65] drilling method. The existing pipe will be replaced with pipe of uniform diameter to accommodate assessment of Line 36-9-09 North using in-line inspection tools.

Table RDP-32
Southern California Gas Company
Line 36-9-09 North Section 15
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
36-9-09 North Section 15	Santa Barbara County	1.5 miles	$14,193

The Line 36-9-09 North Section 15 project will install approximately 1.5 miles of pipe in San Luis Obispo County and will replace pipe installed in 1920. The alignment of the replaced line will remove the line from the existing route, which is too congested with other utility lines to accommodate the new pipeline. The majority of the pipe will be installed using the open trench method with the exception of approximately 350 feet under a creek that will be installed using HDD methods. The existing pipe will be replaced with pipe of uniform diameter to accommodate assessment of Line 36-9-09 North using in-line inspection tools.

Table RDP-33
Southern California Gas Company
Line 36-9-09 North Section 16
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
36-9-09 North Section 16	Santa Barbara County	2.0 miles	$18,036

The Line 36-9-09 North Section 16 project will install approximately two miles of pipe in San Luis Obispo County near the City of San Luis Obispo to replace pipe installed in 1920. The new line will include a re-route in order to follow an existing access road to minimize impacts to environmentally sensitive areas. The majority of the pipe will be installed using the open trench method with the exception of approximately 500 feet that will be installed using HDD methods

[65] A variation of the HDD method.

to accommodate a downhill alignment. The existing pipe will be replaced with pipe of uniform diameter to accommodate assessment of Line 36-9-09 North using in-line inspection tools.

Table RDP-34
Southern California Gas Company
Line 36-1032 Section 11
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
36-1032 Section 11	Santa Barbara County	0.5 miles	$8,692

The Line 36-1032 Section 11 project will install approximately half a mile of pipe in Santa Barbara County near the city of Orcutt to replace pipe installed in 1939 and 1940. The majority of the installation will be completed using the open trench method with the exception of approximately 500 feet underneath a highway that will be addressed utilizing HDD methods, and approximately 150 feet underneath two creek crossings that will be addressed utilizing the jack and bore method.

Table RDP-35
Southern California Gas Company
Line 36-1032 Section 12
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
36-1032 Section 12	Santa Barbara County	5.2 miles	$26,601

The Line 36-1032 Section 12 project will install approximately five miles of pipe in Santa Barbara County south of Lompoc to replace pipe installed in 1943 and 1946. The replaced section will include a re-route to avoid installation within agrarian property, which will enhance safety and reliability by reducing risk of third-party damage from agricultural equipment. Most of the installation will be completed through an open trench excavation method, with the exception of approximately 4,400 feet underneath creeks and culverts that will be installed utilizing HDD methods, and approximately 350 feet under creeks and culverts that will be installed via jack and bore.

Table RDP-36
Southern California Gas Company
Line 36-1032 Section 13
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
36-1032 Section 13	Santa Barbara County	3.2 miles	$17,811

The Line 36-1032 Section 13 project will install approximately three miles of pipe in Santa Barbara County near the city of Lompoc to replace pipe installed in 1928. A re-route of the existing alignment will avoid hillsides where erosion has been experienced and further erosion is anticipated. The pipe will be installed using the open trench method. Due to the proximity of oil pipelines in the area, SoCalGas anticipates contaminated soils may be encountered, which will require proper disposal.

Table RDP-37
Southern California Gas Company
Line 36-1032 Section 14
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
36-1032 Section 14	Santa Barbara County	1.7 miles	$13,937

The Line 36-1032 Section 14 project will install approximately 1.7 miles of pipe in Santa Barbara County near the city of Lompoc to replace pipe installed in 1928. A re-route of the existing alignment will minimize the disturbance of natural vegetation in an ecological reserve and avoid other environmentally sensitive areas. The pipe will be installed using the open trench method.

Table RDP-38
Southern California Gas Company
Line 44-1008
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
44-1008 (50%)	Central California	54.9[66] miles	$76,582

The Line 44-1008 project will install approximately 54.9 miles of pipe in San Luis Obispo and Kings Counties between Paso Robles and Avenal to replace pipe installed in 1937.[67] The replacement project will re-route the existing alignment to facilitate future operation and maintenance activities and improve safety and reliability by reducing the potential for third-party damages. This will also serve to minimize impacts to private property owners and existing farmland. The majority of the pipe will be installed via the open trench method, with the exception of approximately 2.5 miles at various crossings that will installed utilizing HDD methods.

Table RDP-39
Southern California Gas Company
Line 2000-E Cactus City Compressor Station
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
2000-E Cactus City Compressor Station	Riverside County	0.167 miles (883 feet)	$6,698

The Line 2000 Cactus City project will replace approximately 900 feet of pipe within the Cactus City Compressor Station in eastern Riverside County to replace pipe of varying vintages. The replacement addresses mainline station piping associated with the movement of gas within the station.

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[66] Total project mileage.
[67] SoCalGas' showing includes 50% of the estimated project costs. If the Commission grants SoCalGas' request to transition to a four-year GRC cycle, the entire estimated project costs for Line 44-1008 should be included, because the project is anticipated to be placed into service in 2022. For clarity of presentation, the supplemental workpaper details the estimated cost of the entire project.

6. Valve Enhancement Plan

Table RDP-40
Southern California Gas Company
Valve Enhancement Plan
(Direct Costs – Thousands)

Valve Enhancement Plan	Location	Number of Valve Projects	Capital
	Various	284	$246,000

These costs represent continuation of the PSEP Valve Enhancement Plan, as described in Section I.F of my testimony, for years 2019 through 2021. The forecasted costs are based on SoCalGas' experience in the design, permitting, and construction of previously-executed Valve Enhancement Plan projects. Based on this experience, SoCalGas forecasts the level of activity to continue at about the same pace, which results in the completion of the Valve Enhancement Plan in 2021. Completion of the Valve Enhancement Plan will achieve SoCalGas' objective of enabling the automatic or remote isolation of transmission pipeline in 30 minutes or less in the event of a pipeline rupture, thereby enhancing safety.

Table RDP-41 represents the valve project types anticipated to be executed:

Table RDP-41
Southern California Gas Company
Valve Enhancement Plan Forecasted Project Types

Planned Enhancement	Total
Installation of new Automatic Shut-off Valve (ASV)/Remote Control Valve (RCV).	150
Installation of new backflow prevention devices, either with check valve installations or through modifications to existing regulator stations.	80
Installation of new communications equipment to enhance existing valve sites already equipped with ASV/RCV technology.	46
Installation of new flow meters on major transmission pipelines and at major interconnection points.	8
Total	**284**

Detailed information regarding the specific pipelines, locations, and valve forecast methodology is contained in the supplemental workpapers.

X. FOURTH-YEAR PROJECTS

In the event the Commission grants SoCalGas' request for a four-year GRC term, as proposed in the Post-Test Year Ratemaking testimony of Jawaad Malik (Exhibit SCG-44), the following projects are anticipated to be executed in the fourth year (2022).

Table RDP-42
Southern California Gas Company
Fourth-Year Pressure Test Projects[68]
(Direct Costs – Thousands)

Project	Phase	O&M[69]	Capital	Total
225 North	2A	$10,886	$4,578	$15,464
1030	2A	$17,922	$7,433	$25,355
2001 West	2A	$6,996	$1,422	$8,418
2001 East	2A	$13,556	$7,894	$21,450
2005	2A	$2,519	$840	$3,359

Table RDP-43
Southern California Gas Company
Fourth Year Replacement Projects
(Direct Costs – Thousands)

Project	Phase	Capital
2001 East Replacement	2A	$3,799
5000	2A	$4,486
44-1008 (50%)	1B	$76,582

A. Pressure Test Projects

If approved by the Commission, the following pressure test projects would be executed in 2022.

[68] Costs shown do not include implementation continuity costs as described in Section VIII.B.
[69] Includes $868K recorded in Pipeline Safety Enhancement Plan – Phase 2 Memorandum Account (PSEP-P2MA), amortization of which will be sought in a future proceeding.

Table RDP-44
Southern California Gas Company
Line 225 North
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
225 North	Gorman	8.1 miles	$10,886	$4,578	$15,464

The Line 225 North project will pressure test approximately eight miles of pipe near Gorman in Northern Los Angeles County. A portion of the project is located in the Angeles National Forest. Two tests will be conducted using water and three using hydrogen, because water cannot be used over spans located within certain test sections due to weight limitations. A detailed map included in the supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with these test projects include those for the replacement of nine short sections of pipe totaling 592 feet to facilitate the hydrotesting procedure and the replacement of two valves to accommodate assessment of Line 225 North using in-line inspection tools.

Table RDP-45
Southern California Gas Company
Line 1030
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
1030	Riverside County	25.8 miles	$17,922	$7,433	$25,355

The Line 1030 project will pressure test approximately 26 miles of pipe in Eastern Riverside County near Blythe. There will be 14 test sections of varying length to address environmental considerations and elevation changes totaling approximately 900 feet. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this test include the replacement of four taps, the remediation/replacement of three anomalies, and the replacement of 16 short sections of pipe totaling approximately 1,000 feet to facilitate hydrotesting.

Table RDP-46
Southern California Gas Company
Line 2001 West
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
2001 West	Riverside County	5.7 miles	$6,996	$1,422	$8,418

The Line 2001 West project will pressure test approximately six miles of pipe in Eastern Riverside County near Cactus City. There will be three test sections of varying length to address environmental considerations and elevation changes totaling approximately 200 feet. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with these test projects include replacement of four short sections of pipe totaling approximately 190 feet to facilitate hydrotesting.

Table RDP-47
Southern California Gas Company
Line 2001 East
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
2001 East	Riverside County	27.4 miles	$13,556	$7,894	$21,450

The Line 2001 East project will pressure test approximately 27 miles of pipe in Eastern Riverside County between Blythe and Desert Center. The project is comprised of eleven test sections of varying length to address environmental considerations and elevation changes totaling approximately 500 feet. A detailed map included in supplemental workpapers depicts the scope of the project and individual test sections.

The capital costs associated with this project include replacement of one tap and twelve short sections of pipe totaling approximately 640 feet to facilitate hydrotesting.

Table RDP-48
Southern California Gas Company
Line 2005
(Direct Costs – Thousands)

Project	Location	Mileage	O&M	Capital	Total
2005	Riverside County	0.3 miles	$2,519	$840	$3,359

The Line 2001 West Section E project will pressure test approximately .3 miles of pipe in Western Riverside County near Moreno Valley. The test is designed to be conducted in one section. A detailed map included in supplemental workpapers depicts the scope of the project.

The capital costs associated with this project include replacement of two short sections of pipe totaling approximately 70 feet to facilitate hydrotesting.

B. Replacement Projects

If approved by the Commission, SoCalGas proposes to execute the following replacement projects in 2022.

Table RDP-49
Southern California Gas Company
Line 2001 East Replacement
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
2001 East Replacement	Riverside County	0.073 miles (385 feet)	$3,799

The Line 2001 East project will replace approximately 385 feet of pipe in Eastern Riverside County at the Blythe Compressor Station. The project is located entirely within the Blythe Compressor Station and the pipe will be installed using the open trench method.

Table RDP-50
Southern California Gas Company
Line 5000
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
5000	Riverside County	0.015 miles (79 feet)	$4,486

The Line 5000 project will replace approximately 90 feet of pipe at the Blythe Compressor Station. The project is located entirely within the Blythe Compressor Station and the pipe will be installed aboveground, except for a ten-foot section that will be installed using the open trench method.

Table RDP-51
Southern California Gas Company
Line 44-1008
(Direct Costs – Thousands)

Project	Location	Mileage	Capital
44-1008 (50%)	Central California	54.9[70] miles	$76,582

The Line 44-1008 project will install approximately 54.9 miles of pipe in San Luis Obispo and Kings Counties between Paso Robles and Avenal to replace pipe installed in 1937.[71] Re-routes of the existing alignment are included in the scope to facilitate ongoing operations and maintenance on the line in the future and reduce the risk of third-party damage on farmland, thereby enhancing public safety. The re-routes will also minimize impacts to private property owners and existing farmland. Alternatives to replacement of this line are still under consideration.

[70] Total project mileage.
[71] SoCalGas' showing includes 50% of the estimated project costs. If the Commission grants SoCalGas' request to add a fourth year to the GRC cycle, the entire estimated project costs for 44-1008 should be included, as the entire project is anticipated to be placed into service in 2022. For clarity of presentation, the supplemental workpaper describes the cost of the entire project.

Table RDP-52
Southern California Gas Company
Fourth-Year Program Management Office
(Direct Costs – Thousands)

Program Management Office	O&M	Capital[72]	Total
	$3,897	$9,092	$12,989

Refer to Section VIII above for a description of PMO costs.

XI. POST-TEST YEAR COSTS

As described in the testimony of Jawaad Malik (Exhibit SCG-44), PSEP capital-related costs not fully reflected in the TY 2019 revenue requirement are proposed to be included as part of Post-Test Year attrition because the majority of PSEP capital expenditures are expected to close to plant in service in 2020, 2021, and 2022.

Table RDP-48 summarizes by project PSEP Post-Test Year capital costs. The projects are explained in greater detail in Sections VII, VIII, IX, and X of my testimony and in supplemental workpapers:

Table RDP-53
Southern California Gas Company
Post-Test Year Distribution Costs
(Direct Costs – Thousands)

Project	Phase	Capital
36-9-09 North Section 14	1B	$19,980
36-9-09 North Section 15	1B	$14,193
36-9-09 North Section 16	1B	$18,036
36-1032 Section 11	1B	$8,692
36-1032 Section 12	1B	$26,601
36-1032 Section 13	1B	$17,811
36-1032 Section 14	1B	$13,937
44-1008	1B	$153,164
PSEP PMO		$6,259
Fourth Year PSEP PMO		$3,091
Valve Enhancement Plan	1B	$14,760
Total Distribution Capital		**$296,524**

[72] For the purposes of explaining all facets of the PMO in one section, both O&M and Capital forecasts are included here and in the supplemental workpapers.

Table RDP-54
Southern California Gas Company
Post-Test Year Transmission Costs
(Direct Costs – Thousands)

Project	Phase	Capital
407	2A	$962
85 Elk Hills to Lake Station	1B	$88,906
2000-E Cactus City Compressor Station	2A	$6,698
235 West Section 1	2A	$12,106
235 West Section 2	2A	$11,181
235 West Section 3	2A	$3,370
1011	2A	$746
2000 Chino Hills	2A	$11,371
2000 Section E	2A	$1,565
2000 Blythe to Cactus City Hydrotest	2A	$11,908
2001 W Section C	2A	$3,361
2001 W Section D	2A	$4,873
2001 W Section E	2A	$3,000
PSEP PMO		$12,146
Fourth Year PSEP PMO		$6,001
Valve Enhancement Plan	1B	$149,240
Allowance for Pipeline Failures	2A	$4,114
225 North[73]	2A	$4,846
1030[74]	2A	$8,039
2001 West[75]	2A	$1,712
2001 East[76]	2A	$8,462
2005[77]	2A	$927
2001 East Replacement[78]	2A	$3,817
5000[79]	2A	$4,507
Total Transmission Capital		**$363,858**

[73] Includes Implementation Continuity Costs of $268K.
[74] Includes Implementation Continuity Costs of $606K.
[75] Includes Implementation Continuity Costs of $290K.
[76] Includes Implementation Continuity Costs of $568K.
[77] Includes Implementation Continuity Costs of $87K.
[78] Includes Implementation Continuity Costs of $19K.
[79] Includes Implementation Continuity Costs of $20K.

XII. PROJECT SUBSTITUTION

SoCalGas requests authority to substitute one or more PSEP project(s) with other PSEP projects in the event there is a delay in commencing construction of one of the projects presented for approval in this Application due to circumstances not within SoCalGas' control (*e.g*., if there is a delay in obtaining a necessary permit or land rights) or when it is prudent to accelerate the execution of a PSEP project for operational, reliability or safety enhancement reasons (*e.g*, if pressure testing of a segment of a pipeline is accelerated to address identification of a known integrity threat or following a pipeline rupture). To illustrate, as a result of a service rupture of Line 235 in October, 2017, SoCalGas is proceeding with remediating the affected sections of pipeline. The starting and ending points of remediation are still being determined, but are anticipated to encompass at least a portion of pressure test projects Line 235 Section 1 and Line 235 Section 2 described on pages RDP A-28 and RDP A-29 of my testimony.[80]

When substitution is necessitated, substitute projects would be selected such that the costs of completing the substituted project(s) would not cause SoCalGas to exceed the aggregate amount authorized for recovery by a decision on this Application. Prior to substituting one approved PSEP project for another PSEP project, SoCalGas proposes to file a Tier One advice letter to notify the Commission and interested parties of the following: (1) the name and general scope of the delayed project; (2) the circumstances that led to the change in the execution timing of the substituted project; (3) identification of the PSEP project(s) to be executed in lieu of the substituted project; (4) a description of the scope of the substitute project; and (5) an estimate of the costs to complete the substitute project.

XIII. CLARIFICATION OF COMMISISON GUIDANCE REGARDING "MODERN STANDARDS"

As discussed above, in D.11-06-017 the Commission concluded "that all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety. Historic exemptions must come to an end with an orderly and cost-

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[80] Further details on these projects are set forth in Exhibit SCG-15-S, pages WP-I-A1 through WP-I-A34.

conscious implementation plan."[81] In furtherance of this directive, the Commission ordered SoCalGas and other California pipeline operators to "file and serve a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) to comply with the requirement that all in-service natural gas transmission pipelines in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)" (emphasis added).[82] SoCalGas understands this language in D.11-06-017 to require gas utilities to propose a plan to validate that all in-service natural gas transmission pipelines in California have "been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)," i.e., to the "modern standard" set by 49 CFR 192 Subpart J (Subpart J).

In prior PSEP proceedings, parties have expressed different interpretations of the above language and questioned whether pipelines pressure tested prior to the adoption of Subpart J are required to be addressed by California pipeline operators.

SoCalGas requests the Commission clarify State policy regarding pipelines that have documentation of a pressure test that pre-dates the adoption of federal pressure testing requirements (categorized as Phase 2B in SoCalGas and SDG&E's PSEP). Although there are no standalone projects addressing this category of pipe presented for review in this Application,[83] SoCalGas and SDG&E have been addressing some Phase 2B pipeline segments in conjunction with Phase 1 and 2A work, where doing so furthers PSEP objectives to minimize costs to and impacts on customers and surrounding communities or to enhance constructability. Resolution of this issue in this Application will enable SoCalGas and SDG&E to prudently design and plan remaining PSEP projects.

XIV. CONCLUSION

My testimony supports SoCalGas' request to proceed with construction of eleven Phase 2A pressure test projects, one Phase 2A replacement project, ten Phase 1B replacement projects, and 284 Valve Enhancement Plan projects, and to recover in rates $249,467,456 O&M

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[81] D.11-06-017 at 18.
[82] D.11-06-017 at 31 (Ordering ¶ 4) (emphasis added).
[83] As described in Section II.A above, some projects included here include Phase 2B mileage that is "accelerated" to improve program and cost efficiency, address implementation constraints, or facilitate the continuity of pressure testing.

and the capital expense associated with $649,326,239 Capital, each on an aggregate basis, for the pipeline and valve projects presented in this Application, in the continuing implementation of PSEP. My testimony also includes a request for authorization to substitute PSEP pipeline or valve projects approved in this Application with one or more other PSEP projects in the event construction of an approved project is delayed and seeks authorization to continue to record and balance PSEP costs in the PSEPBA two-way balancing account. Further, my testimony seeks clarification of State policy regarding transmission pipelines that have documentation of a pressure test that pre-dates the adoption of federal pressure testing regulations in 1970. Approval of these requests will enable SoCalGas to continue to accomplish the Commission's and Legislature's pipeline safety objectives and meet the PSEP objectives to: (1) enhance public safety; (2) comply with Commission directives; (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments.

XV. WITNESS QUALIFICATIONS

My name is Rick Phillips. My current position is Senior Director, Pipeline Safety Enhancement Plan

I have been employed by SoCalGas since 1978. I have held Director level positions in Engineering, Supply Management, Gas Distribution, Electric Distribution, Customer Services, IT, and Storage, as well as a manager position in gas transmission pipeline services.

I have a Bachelor's degree in Engineering from University of California, Irvine, cum laude. I am a registered Professional Engineer in California. I have a certificate in Executive Management from the University of Michigan and a certificate in Finance for Executives from the University of Chicago. I was a member of the Pipeline Research Council International.

I have testified previously before this Commission.

This concludes my prepared direct testimony.

SoCalGas 2019 GRC Testimony Revision Log – March 2018

Exhibit	Witness	Page	Revision Detail
SCG-15	Rick Phillips	RDP-A-56	Updated Section XII. - Project Substitution to include a request for substitution when it is prudent to accelerate the execution of a PSEP project for operational, reliability or safety enhancement reasons.

EXHIBIT B

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Presidential Proclamation on Adjusting Imports of Steel into the United States

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1. On January 11, 2018, the Secretary of Commerce (Secretary) transmitted to me a report on his investigation into the effect of imports of steel mill articles (steel articles) on the national security of the United States under section 232 of the Trade Expansion Act of 1962, as amended (19 U.S.C. 1862).

2. The Secretary found and advised me of his opinion that steel articles are being imported into the United States in such quantities and under such circumstances as to threaten to impair the national security of the United States. The Secretary found that the present quantities of steel articles imports and the circumstances of global excess capacity for producing steel are "weakening our internal economy," resulting in the persistent threat of further closures of domestic steel production facilities and the "shrinking [of our] ability to meet national security production requirements in a national emergency." Because of these risks and the risk that the United States may be unable to "meet [steel] demands for national defense and critical industries in a national emergency," and taking into account the close relation of the economic welfare of the Nation to our national security, see 19 U.S.C. 1862(d), the Secretary concluded that the present quantities and circumstances of steel articles imports threaten to impair the national security as defined in section 232 of the Trade Expansion Act of 1962, as amended.

3. In reaching this conclusion, the Secretary considered the previous U.S. Government measures and actions on steel articles imports and excess capacity, including actions taken under Presidents Reagan, George H.W. Bush, Clinton, and George W. Bush. The Secretary also considered the Department of Commerce's narrower investigation of iron ore and semi-finished steel imports in 2001, and found the recommendations in that report to be outdated given the dramatic changes in the steel industry since 2001, including the increased level of global excess capacity, the increased level of imports, the reduction in basic oxygen furnace facilities, the number of idled facilities despite increased demand for steel in critical industries, and the potential impact of further plant closures on capacity needed in a national emergency.

4. In light of this conclusion, the Secretary recommended actions to adjust the imports of steel articles so that such imports will not threaten to impair the national security. Among those recommendations was a global tariff of 24 percent on imports of steel articles in order to reduce imports to a level that the Secretary assessed would enable domestic steel producers to use approximately 80 percent of existing domestic production capacity and thereby achieve long-term economic viability through increased production. The Secretary

has also recommended that I authorize him, in response to specific requests from affected domestic parties, to exclude from any adopted import restrictions those steel articles for which the Secretary determines there is a lack of sufficient U.S. production capacity of comparable products, or to exclude steel articles from such restrictions for specific national security-based considerations.

5. I concur in the Secretary's finding that steel articles are being imported into the United States in such quantities and under such circumstances as to threaten to impair the national security of the United States, and I have considered his recommendations.

6. Section 232 of the Trade Expansion Act of 1962, as amended, authorizes the President to adjust the imports of an article and its derivatives that are being imported into the United States in such quantities or under such circumstances as to threaten to impair the national security.

7. Section 604 of the Trade Act of 1974, as amended (19 U.S.C. 2483), authorizes the President to embody in the Harmonized Tariff Schedule of the United States (HTSUS) the substance of acts affecting import treatment, and actions thereunder, including the removal, modification, continuance, or imposition of any rate of duty or other import restriction.

8. In the exercise of these authorities, I have decided to adjust the imports of steel articles by imposing a 25 percent ad valorem tariff on steel articles, as defined below, imported from all countries except Canada and Mexico. In my judgment, this tariff is necessary and appropriate in light of the many factors I have considered, including the Secretary's report, updated import and production numbers for 2017, the failure of countries to agree on measures to reduce global excess capacity, the continued high level of imports since the beginning of the year, and special circumstances that exist with respect to Canada and Mexico. This relief will help our domestic steel industry to revive idled facilities, open closed mills, preserve necessary skills by hiring new steel workers, and maintain or increase production, which will reduce our Nation's need to rely on foreign producers for steel and ensure that domestic producers can continue to supply all the steel necessary for critical industries and national defense. Under current circumstances, this tariff is necessary and appropriate to address the threat that imports of steel articles pose to the national security.

9. In adopting this tariff, I recognize that our Nation has important security relationships with some countries whose exports of steel articles to the United States weaken our internal economy and thereby threaten to impair the national security. I also recognize our shared concern about global excess capacity, a circumstance that is contributing to the threatened impairment of the national security. Any country with which we have a security relationship is welcome to discuss with the United States alternative ways to address the threatened impairment of the national security caused by imports from that country. Should the United States and any such country arrive at a satisfactory alternative means to address the threat to the national security such that I determine that imports from that country no longer threaten to impair the national security, I may remove or modify the restriction on steel articles

imports from that country and, if necessary, make any corresponding adjustments to the tariff as it applies to other countries as our national security interests require.

10. I conclude that Canada and Mexico present a special case. Given our shared commitment to supporting each other in addressing national security concerns, our shared commitment to addressing global excess capacity for producing steel, the physical proximity of our respective industrial bases, the robust economic integration between our countries, the export of steel articles produced in the United States to Canada and Mexico, and the close relation of the economic welfare of the United States to our national security, see 19 U.S.C. 1862(d), I have determined that the necessary and appropriate means to address the threat to the national security posed by imports of steel articles from Canada and Mexico is to continue ongoing discussions with these countries and to exempt steel articles imports from these countries from the tariff, at least at this time. I expect that Canada and Mexico will take action to prevent transshipment of steel articles through Canada and Mexico to the United States.

11. In the meantime, the tariff imposed by this proclamation is an important first step in ensuring the economic viability of our domestic steel industry. Without this tariff and satisfactory outcomes in ongoing negotiations with Canada and Mexico, the industry will continue to decline, leaving the United States at risk of becoming reliant on foreign producers of steel to meet our national security needs — a situation that is fundamentally inconsistent with the safety and security of the American people. It is my judgment that the tariff imposed by this proclamation is necessary and appropriate to adjust imports of steel articles so that such imports will not threaten to impair the national security as defined in section 232 of the Trade Expansion Act of 1962, as amended.

Now, Therefore, I, Donald J. Trump, President of the United States of America, by the authority vested in me by the Constitution and the laws of the United States of America, including section 301 of title 3, United States Code, section 604 of the Trade Act of 1974, as amended, and section 232 of the Trade Expansion Act of 1962, as amended, do hereby proclaim as follows:

(1) For the purposes of this proclamation, “steel articles” are defined at the Harmonized Tariff Schedule (HTS) 6-digit level as: 7206.10 through 7216.50, 7216.99 through 7301.10, 7302.10, 7302.40 through 7302.90, and 7304.10 through 7306.90, including any subsequent revisions to these HTS classifications.

(2) In order to establish increases in the duty rate on imports of steel articles, subchapter III of chapter 99 of the HTSUS is modified as provided in the Annex to this proclamation. Except as otherwise provided in this proclamation, or in notices published pursuant to clause 3 of this proclamation, all steel articles imports specified in the Annex shall be subject to an additional 25 percent ad valorem rate of duty with respect to goods entered, or withdrawn from warehouse for consumption, on or after 12:01 a.m. eastern daylight time on March 23, 2018. This rate of duty, which is in addition to any other duties, fees, exactions, and charges

applicable to such imported steel articles, shall apply to imports of steel articles from all countries except Canada and Mexico.

(3) The Secretary, in consultation with the Secretary of State, the Secretary of the Treasury, the Secretary of Defense, the United States Trade Representative (USTR), the Assistant to the President for National Security Affairs, the Assistant to the President for Economic Policy, and such other senior Executive Branch officials as the Secretary deems appropriate, is hereby authorized to provide relief from the additional duties set forth in clause 2 of this proclamation for any steel article determined not to be produced in the United States in a sufficient and reasonably available amount or of a satisfactory quality and is also authorized to provide such relief based upon specific national security considerations. Such relief shall be provided for a steel article only after a request for exclusion is made by a directly affected party located in the United States. If the Secretary determines that a particular steel article should be excluded, the Secretary shall, upon publishing a notice of such determination in the Federal Register, notify Customs and Border Protection (CBP) of the Department of Homeland Security concerning such article so that it will be excluded from the duties described in clause 2 of this proclamation. The Secretary shall consult with CBP to determine whether the HTSUS provisions created by the Annex to this proclamation should be modified in order to ensure the proper administration of such exclusion, and, if so, shall make such modification to the HTSUS through a notice in the Federal Register.

(4) Within 10 days after the date of this proclamation, the Secretary shall issue procedures for the requests for exclusion described in clause 3 of this proclamation. The issuance of such procedures is exempt from Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs).

(5) (a) The modifications to the HTSUS made by the Annex to this proclamation shall be effective with respect to goods entered, or withdrawn from warehouse for consumption, on or after 12:01 a.m. eastern daylight time on March 23, 2018, and shall continue in effect, unless such actions are expressly reduced, modified, or terminated.

(b) The Secretary shall continue to monitor imports of steel articles and shall, from time to time, in consultation with the Secretary of State, the Secretary of the Treasury, the Secretary of Defense, the USTR, the Assistant to the President for National Security Affairs, the Assistant to the President for Economic Policy, the Director of the Office of Management and Budget, and such other senior Executive Branch officials as the Secretary deems appropriate, review the status of such imports with respect to the national security. The Secretary shall inform the President of any circumstances that in the Secretary's opinion might indicate the need for further action by the President under section 232 of the Trade Expansion Act of 1962, as amended. The Secretary shall also inform the President of any circumstance that in the Secretary's opinion might indicate that the increase in duty rate provided for in this proclamation is no longer necessary.

(6) Any provision of previous proclamations and Executive Orders that is inconsistent with the actions taken in this proclamation is superseded to the extent of such inconsistency.

IN WITNESS WHEREOF, I have hereunto set my hand this

eighth day of March, in the year of our Lord two thousand eighteen, and of the Independence of the United States of America the two hundred and forty-second.

DONALD J. TRUMP

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EXHIBIT C

Application No: A.16-09-XXX
Exhibit No:
Witness: R. Phillips

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) to Recover Costs Recorded in the Pipeline Safety and Reliability Memorandum Accounts, the Safety Enhancement Expense Balancing Accounts, and the Safety Enhancement Capital Cost Balancing Accounts	Application 16-09-XXX

CHAPTER II

DIRECT TESTIMONY OF

RICK PHILLIPS

ON BEHALF OF

SOUTHERN CALIFORNIA GAS COMPANY

AND

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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I. PURPOSE AND OVERVIEW OF TESTIMONY

The purpose of my testimony is to describe the prudent project execution and proactive cost management measures taken by Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (collectively "Utilities") in the development and execution of SoCalGas and SDG&E's Pipeline Safety Enhancement Plan (PSEP).

First and foremost, the execution of the Utilities' PSEP exemplifies their approach to safety. As fully set forth in the testimony of Jimmie Cho, the Utilities undertook these efforts expeditiously, almost two years before receiving formal guidance from the Commission. The Utilities did so because they had received notice from the Commission that this important safety work should be done "as soon as practicable." That's what SoCalGas and SDG&E did – prioritized work in highly populated areas and began testing and replacing as they believed to be prudent at the time, based on their experience and knowledge of their own systems. As fully set forth throughout my testimony, this commitment to safety has not wavered. The Utilities' commitment to safety, their expeditious approach to testing and replacing pipelines as required by the Commission and the Legislature, and their prudence in doing so should be acknowledged by the Commission. As such, the Utilities should receive full rate recovery – minus acknowledged disallowances – for this important safety work.

PSEP's successful execution not only complies with Commission orders and California Public Utilities Code Section 958, but, by efficiently enhancing the safety of our transmission pipeline system, PSEP has provided and will continue to provide value to customers for decades to come. In my testimony, I will describe how SoCalGas and SDG&E:

- Have created a PSEP organization to safely, prudently, and expeditiously execute PSEP to enhance the safety of the Utilities' transmission systems.

- Are diligent in looking for ways to avoid costs. For example, the overall Phase 1A scope has been reduced by approximately 260 Category 4[1] miles at an estimated avoided cost of over $500 million.

- Follow a least cost approach – given the conditions encountered for each project – to plan, engineer, and complete the individual pipeline and valve projects.

- Obtain market-based rates for material and services through competitive sourcing efforts.

- Despite their best efforts to manage costs, encountered common challenges that drive project costs and explain why the challenges encountered by the Utilities are similar to challenges experienced in other large, complex construction programs.

The Utilities' PSEP undertaking is the largest natural gas infrastructure safety enhancement in SoCalGas and SDG&E's history. Phase 1A is currently expected to include approximately 168 pipeline and valve projects and involves over 500 SoCalGas and SDG&E dedicated employees and contractor personnel.[2] [3] As fully set forth below, where there have been opportunities to control costs – such as through competitive sourcing, the development of the Performance Partnership Program, and scope validation – PSEP has been successful in doing so. For example, by using internal expertise and critical assessments of each project, the Utilities estimate that they have avoided several hundred million dollars in project costs which would have otherwise been borne by customers. When challenges have been encountered – such as delayed construction, traffic control or environmental permits and land acquisition delays – they have been addressed as expeditiously and cost effectively as possible. Pressure test projects were completed prudently without pipeline failures and served to validate the safety of our existing pipelines. Replacement projects were completed successfully, prudently, and served to

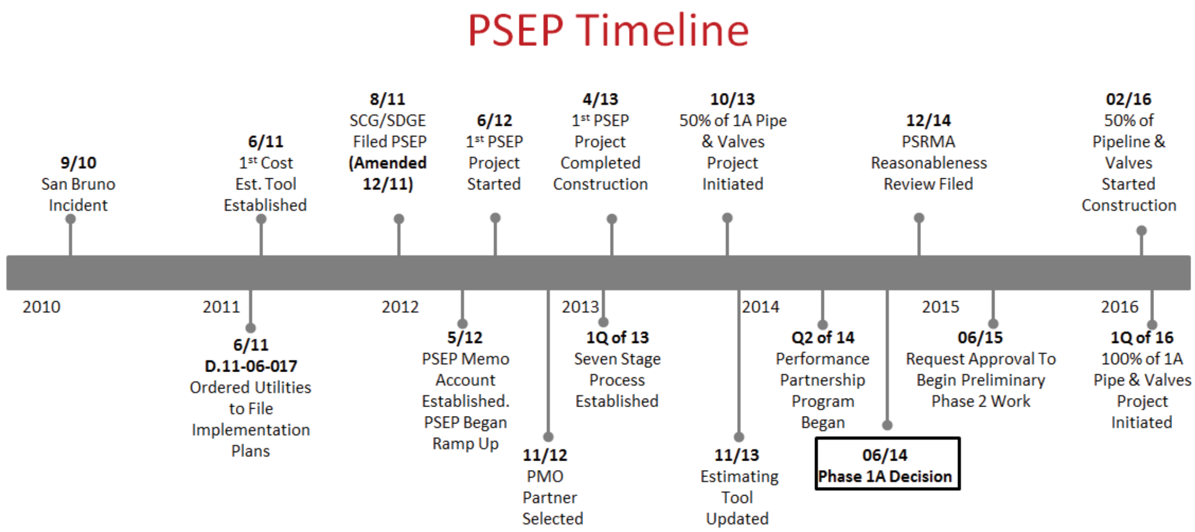
[1] Category 4 includes pipelines that lack sufficient documentation of a post-construction strength test to 1.25xMAOP.
[2] Figures as of April 2016.
[3] Contractor figures do not include construction contractor personnel.

update our system to include more pipelines that were manufactured and installed using modern standards for safety.

This application demonstrates the prudence with which SoCalGas and SDG&E have executed PSEP and the reasonableness of the costs presented for review and recovery. Our actions have enhanced safety; mitigated customer impacts; and avoided and reduced costs. SoCalGas and SDG&E have implemented PSEP prudently, at reasonable costs, behaved as reasonable managers of PSEP given the information that was known at the time, and should receive full cost recovery of the revenue requirement requested in this application.

II. PSEP TIMELINE OF EVENTS

Consistent with Commission directives to begin PSEP work as soon as practicable, SoCalGas and SDG&E began implementing PSEP prior to the Commission issuing D.14-06-007 – which approved the PSEP – in June of 2014 (hereafter the "PSEP Decision"). SoCalGas and SDG&E created the PSEP organization, began developing the necessary PSEP programs and processes, and began PSEP work in 2012. In fact, the 41 pipeline and valve projects included in this application were initiated prior to receiving the PSEP Decision. The processes and programs that were created to accomplish the safety enhancement efforts continue to evolve and grow as PSEP continues, but are guided by the Utilities stated PSEP mission to: (1) enhance public safety; (2) comply with the Commission's directives; (3) minimize customer impacts; and (4) maximize the cost-effectiveness of safety investment. The following timeline depicts milestones in developing and executing PSEP:



Notably, two years transpired between the beginning of the first PSEP project in June, 2012 and the issuance of the PSEP Decision, which provided guidance regarding the after-the-fact cost recovery through reasonableness reviews. Therefore, because of instructions to begin work "as soon as practicable," by the time the decision was issued, PSEP's foundation had been set and the work was well underway.

Phase 1A, the first phase of PSEP, was designed to address the most densely populated areas. The total scope of Phase 1A is currently anticipated to be approximately 175 miles (of which 95 miles are Category 4[4]), a valve enhancement program to augment existing automatic shutoff and remote control valves to minimize the amount of time required to stop the flow of gas in the event of a pipeline rupture, and technology enhancements such as the installation of methane monitoring devices to enable quicker leak detection. The scope currently encompasses approximately 112 individually planned and constructed pipeline projects and 56 individually planned and constructed valve bundle projects. These projects and activities span the Utilities'

[4] The remaining non-Category 4 miles are incidental or accelerated miles included to realize efficiencies or improve constructability.

entire service territory, which stretches from the Mexican border to Central California and serves approximately 24 million customers. As of the filing of this application, approximately 105 miles have been pressure tested or replaced, 35 valve bundle projects have been completed, and 25 methane detectors have been installed along with associated monitoring systems.

III. PSEP IS BEING IMPLEMENTED WITH SAFETY AND COST EFFECTIVENESS IN MIND

A. The PSEP Organization Is Designed to Promote Prudent PSEP Implementation

The work scheduled for the Utilities' PSEP is extensive, both in terms of the volume of projects and time necessary to complete each project. The PSEP organization was created to manage not only a large volume of work safely and cost-effectively, but also manage both employees and contractors. The PSEP organization oversees PSEP project execution, provides project and process controls during the project life cycle, allows SoCalGas and SDG&E to assess each project's budget and schedule, and communicates PSEP progress to stakeholders.

The first step in creating the PSEP organization was the formation of separate PSEP departments with PSEP-focused roles and responsibilities to effectively and efficiently manage safety enhancement. The separate roles and responsibilities within the PSEP organization provide for functional guidance on the various aspects of project design and construction and project oversight. While all departments and personnel associated with the implementation of the SoCalGas and SDG&E PSEP are important in accomplishing the PSEP objectives, there are nine specific groups that oversee critical aspects of the PSEP functions: (1) the Program Management Office (PMO); (2) Construction; (3) Engineering; (4) Environmental; (5) Supply Management; (6) Gas Control; (7) Non-PMO General Administration; (8) Communication and

Outreach; and (9) Training. Depending on their function, these groups support and/or execute PSEP projects.[5]

B. The PSEP Organization Is Subject to Prudent Governance and Oversight

PSEP is a large and complex program that requires appropriate governance and management to achieve its goal of cost effectively enhancing safety. The PSEP governance and management strategy is to comply with applicable regulatory requirements, continuously improve, and establish proper controls and management across PSEP functional areas to verify that design, material procurement, construction, and closeout is performed correctly and consistently.

To accomplish the above goals, PSEP-specific governance and management efforts were undertaken. The PSEP project management office (PMO) was established. The PMO provides oversight at the organizational level, helps develop PSEP policies to promote oversight and accountability, and develops reporting metrics to keep SoCalGas and SDG&E management apprised of PSEP progress. As acknowledged by the Safety and Enforcement Division (SED) (formerly known as the Consumer Protection and Safety Division) in their 2012 Technical Report on the SoCalGas and SDG&E PSEP, this oversight and management function is prudently placed with one central department: "CPSD believes the Companies are approaching the need to manage the PSEP in a reasonable manner and that the PMO will be critical to the proper execution of PSEP."[6] SED's assessment has proven to be true. The following are key PMO functions:

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[5] PSEP support groups and costs are discussed further in Chapter VII (Mejia) and VIII (Tran).

[6] Technical Report of the Consumer Protection and Safety Division Regarding the Southern California Gas Company and San Diego Gas and Electric Company Pipeline Safety Enhancement Plan dated January 17, 2012, at page 22.

First, the PMO collaborates, coordinates, and provides functional guidance on project design and construction to cost effectively meet or exceed compliance requirements and follow, as appropriate, industry best practices. The PMO, and the governance and management structure, is designed to promote safety and efficiency by providing structure, guidance, and oversight. In addition to its safety focus, the PMO also oversees implementation, provides checks and balances during the project life cycle, and allows SoCalGas and SDG&E to assess whether projects are within budget, on schedule, and meet schedule, cost, quality, customer impact, and compliance goals.

Second, the PMO develops standards and procedures for the Utilities' PSEP that enables PSEP to be executed in a consistent manner across projects. These standards and procedures, besides including PSEP-specific information to improve safety and efficiency, also incorporate SoCalGas and SDG&E's existing requirements for design, material acquisition, construction, construction inspection, documentation, and environmental compliance.

Third, the PMO develops reports and Key Performance Indicators (KPIs) at both the granular project level and the overall PSEP level. SoCalGas and SDG&E management, on a monthly basis, review the KPIs to monitor PSEP. Included in the KPIs are financial metrics, pressure testing and replacement progress metrics (e.g., number of projects that have entered construction and placed into service), valve metrics (e.g., number of valves that have entered construction and been placed into service), safety metrics, environmental compliance metrics, material availability metrics, Diverse Business Enterprise goals, and headcount. Qualitative data is reviewed by the PSEP PMO and SoCalGas and SDG&E Management including a summary of key accomplishments, constraints, and opportunities for improvement.

C. The PSEP is Subject to Prudent Decision Making Processes

It is important to assess how various PSEP project options and approaches may impact SoCalGas and SDG&E's system. As explained in Chapter III (Phillips), SoCalGas and SDG&E continue to use the Decision Tree and concepts approved by the Commission in D.14-06-007 during Stage 2 (Test or Replace Analysis) of the Seven Stage Review Process (see below). In addition, as described in Chapter IV (Bermel), a detailed process is used to determine the scope of work of the Valve Enhancement Plan.

An integral part of the analysis that results in prudent decision making is the collaboration by PSEP with other knowledgeable groups (e.g. Region Operations, Engineering, Gas Transmission Planning, Gas Control, Marketing, Public Affairs, etc.) to route, design, and schedule pipeline and valve work to minimize costs and accommodate capacity impacts or restrictions. For example, these groups provide information to guide project specific decisions including (1) the feasibility of shut-ins and alternate feeds to regulator stations or customers; (2) customer and community impacts; and (3) environmental requirements, right-of-way, and permitting needs. All of this information is used to help determine the scope and constructability of the project.[7]

D. The PSEP Seven Stage Review Process Promotes Efficient Project Execution

The Seven Stage Review Process sequences and schedules PSEP project workflow deliverables.[8] The Seven Stage Review Process consists of seven stages with specific objectives for each stage and an evaluation at the end of each stage to verify that objectives have been met

[7] Please see Chapter IV (Bermel) for a discussion of the Valve Enhancement Plan scoping process.
[8] The Seven Stage Review Process was implemented by the PSEP organization beginning in the First Quarter of 2013. Thus, PSEP projects that were initiated prior to that time did not follow this formalized process. A similar, but less formal, project execution methodology was employed in those instances.

before proceeding to the next stage.[9] During the Seven Stage Review Process there are numerous notable activities, but the decisions most affecting project scope is the decision to test or replace, divide segments, and include accelerated and/or incidental mileage.[10] The following is a description of each of the seven stages:

Stage 1 (Project Initiation) is where the Work Order Authorization (WOA) is initiated. The initial WOA is used to track costs for the early stage investigation and validation of Category 4 Criteria mileage and present a project recommendation and package for approval to Stage 2. The Project Initiation Stage is where mileage originally included for remediation may be decreased due to scope validation efforts, reduction in Maximum Allowable Operating Pressure (MAOP), or abandonment of lines that were no longer required from a gas operating system perspective.

Stage 2 (Test or Replace Analysis) is where SoCalGas and SDG&E analyze data for selection of testing or replacement. Project execution options are presented and considered prior to proceeding to the next stage.

Stage 3 (Begin Detailed Planning) is where a project execution plan is finalized, baseline schedules are developed, funding estimates are developed, and project funding is obtained.

Stage 4 (Detailed Design/Procurement) is where design and construction documents are completed, necessary permits and authorizations are attained, a construction contractor is selected, and pipeline materials are purchased, received, and prepared for turnover to contractors.

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[9] Evaluations are gate reviews or completion check lists. Certain stages are condensed or combined for valve and small pipeline projects.

[10] Accelerated miles are miles that would otherwise be addressed in a later phase of PSEP under the approved prioritization process, but are being advanced to Phase 1A to realize operating and cost efficiencies. Incidental miles are miles not scheduled to be addressed in PSEP, but are included where their inclusion is determined to improve cost and program efficiency, address implementation constraints, or facilitate continuity of testing.

Stage 5 (Construction) is where construction contractors are mobilized and monitored to: (1) document progress and compliance; (2) conduct testing; and (3) maintain project scope quality, budget, and schedule.

Stage 6 (Place into Service) is where commissioning and operating activities are performed to achieve completion certification for the project.

Stage 7 (Closeout) is where regulatory, contractual, archival activities are performed to close the project in an orderly manner and issue acceptance certificates.

E. Scope Validation Efforts Have Identified Cost Avoidance Opportunities

A key first step in project execution is the scope validation efforts conducted in Stage 1 (Project Initiation). SoCalGas and SDG&E do not proceed with the projects identified in the initial PSEP Application[11] without first performing due diligence to verify the project scope through scope validation. From the initial phase of a PSEP project, the PSEP management team identifies the potential for cost avoidance when studying the proposed project. To do this, data from the initial PSEP application and internal databases are reviewed by the project team to validate project mileage. Through this scope validation step, mileage reduction may be accomplished through the critical assessment of records, reduction in Maximum Allowable Operation Pressure (MAOP), or abandonment of lines that that were no longer required from an overall gas operating system perspective.[12]

There has been verifiable cost avoidance due to the proactive nature of the Utilities' PSEP scope validation. The scope of Phase 1A in the initial PSEP Application was 355

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[11] SoCalGas and SDG&E's PSEP was original filed in R.11-02-019.

[12] Lines are only abandoned after a thorough review of the ability of adjoining lines to meet current and future load requirements and to verify there will be no customer impact or system constraints.

Category 4 miles.[13] Through scope validation, the current Phase 1A mileage is approximately 95 miles of Category 4 – an approximately 260-mile reduction.[14] [15] 32 Phase 1A projects, totaling 36 Category 4 miles have been completely eliminated from PSEP due to scope validation efforts. As a result, SoCalGas and SDG&E have avoided an estimated project–to–date cost of over $500 million. These efforts exemplify the Utilities prudent management of PSEP.

The PSEP team plans to continue its proactive scope validation and to mitigate costs when possible and appropriate. For example, initial scope validation is underway to validate the Phase 1B[16] mileage identified in the initial PSEP Application. Through the initial Project Initiation stage review, it was determined that three pipelines totaling 15 miles of pipe could be abandoned, eliminating the need to replace these segments. Additionally, for another Phase 1B pipeline with 27 miles initially in scope, the project team undertook a segment by segment review, taking into consideration system capacity and customer requirements. The results of the review resulted in 9 miles being abandoned and 11 miles lowered in pressure, thereby avoiding the replacement of 20 miles. The scope validation efforts have and continue to result in avoided costs for our customers.

F. PSEP has Implemented Prudent Community Outreach Efforts

Phase 1A projects are located in populated areas. As such, a proactive community outreach effort is an integral part of keeping customers, elected officials, and government entities informed about PSEP projects taking place in their communities. Approximately 6,000 customer notification letters and 4,000 door hangers were delivered to customers along the route of the 41

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[13] Excludes Line 1600, which is the subject of a separate application: A.15-09-013.
[14] Mileage figures do not include accelerated or incidental miles as defined in Chapter III (Phillips).
[15] As directed in D.14-06-007, a reconciliation of the mileage contained in the original PSEP Application to the mileage of the projects included in this application is contained in Chapter III (Phillips).
[16] For the purposes of discussion here, Phase 1B refers to pre-1946 non-piggable pipe.

PSEP projects included in this application. Numerous meetings were held with elected officials and municipal agencies to provide advance notice and ongoing updates regarding PSEP projects. Additionally, PSEP established a web page providing background information, construction activities, and project status to give customers and stakeholders easier access to information. Through media and public service announcements placed in the SoCalGas and SDG&E service territory, views to the websites increased by 65% between the First and Second Quarters of 2015. These outreach efforts were instrumental in avoiding project delays and, in some instances, resulted in less onerous permit conditions being imposed on SoCalGas and SDG&E. For example, ongoing communications with the city of Arroyo Grande on the Line 36-9-09 North Section 6A project, helped ensure permits were issued on schedule. In addition, SoCalGas and SDG&E successfully mitigated a list of permit conditions that would have resulted in higher project costs. The city, in response to an inquiry by an inspector from the SED, praised SoCalGas for their proactive outreach efforts. An inquiry from a local television station regarding the project resulted in a positive story on the 36-9-09 North Section 6A project.[17]

IV. THE UTILITIES' PSEP USES INTERNAL AND CPUC OVERSIGHT TO PRUDENTLY MANAGE THE PROGRAM

PSEP complies with SoCalGas and SDG&E's Gas Standards, applicable laws and regulations, and involves SED oversight to prudently and lawfully manage the safety enhancement work.

SoCalGas and SDG&E's Gas Standards comprise the policy and procedures that govern the design, construction, operations, and maintenance of the transmission and distribution systems. For each project, the Gas Standards and other internal standards and practices are

[17] See: http://www.keyt.com/news/arroyo-grande-gas-pipes-pass-inspection/32677812

employed to govern the design analysis,[18] materials purchased,[19] and construction practices.[20] The Gas Standards have dual objectives: to comply with relevant and current applicable laws and regulations and promote safety and operational efficiency.

Gas Standards are updated by the Utilities as necessary. The SED regularly reviews the natural gas transmission and distribution functions for each utility providing natural gas in the state. The SED compares the functions of transmission and distribution with requirements set out by General Order (GO) 112-E,[21] which incorporate federal standards. Through these reviews SED evaluates and provides input on the Gas Standards to promote compliance with GO 112-E and referenced provisions of Title 49 of the Code of Federal Regulations (49 CFR).

In addition to SoCalGas and SDG&E's own internal oversight efforts, SED has closely interacted with SoCalGas and SDG&E in the successful execution of PSEP projects. As ordered by D.14-06-007,[22] SED provides oversight on various aspects of PSEP with emphasis on

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[18] PSEP design standards and practices address materials to be used and proper design in accordance with GO 112-E and applicable federal laws and regulations. PSEP design standards and practices enable: (1) the development of specific engineering requirements for materials used in PSEP projects; (2) preparation of designs that comply with applicable laws, permits, SoCalGas/SDG&E, and industry standards; (3) utilization of applicable engineering and design standards developed for PSEP; (4) consistent design and material requirements for the various engineering design firms contract to assist with design development; and (5) the development of a project-specific design basis for each PSEP project.

[19] Once the PSEP project has been scoped, designed, and approved, materials are ordered that comply with SoCalGas and SDG&E's Materials Specifications for Gas Operations (MSPs). Unless otherwise specified, API 5L pipe, with the specific approved grades and wall thicknesses, are used.

[20] Construction is subject to extensive standards, practices, and guidelines. SoCalGas and SDG&E have implemented comprehensive standards that address, among other areas, excavation, coating application and inspection, welding, welding inspection, trenching, cover, and pressure testing. Prior to starting work, as a part of the agreement with the contractor, contractors are provided an index of standards, practices, guidelines, and requirements; as applicable, contractors are provided updates when issued. SoCalGas and SDG&E monitor and document compliance with applicable standards, laws, and requirements.

[21] In R.11-02-019, the Commission approved revisions to General Order 112 (*see* D.15-06-044). New General Order 112-F is not mandatorily effective until January 1, 2017 (*see* D.15-06-044, mimeo., at 15).

[22] D.14-06-007, mimeo., at 29 ("Specific to SDG&E and SoCalGas's Safety Enhancement we delegate to Safety Div. the specific authority to directly observe and inspect the testing, maintenance and construction, and all other technical aspects of Safety Enhancement to ensure public safety both during

construction activities and recordkeeping. SED personnel are routinely onsite at PSEP construction projects and monitor compliance with applicable regulations.

PSEP also has had an outstanding safety record with an Occupational and Safety Health Administration (OSHA) incident rate of 0.47, well below the industry average of 1.2. All Company employees and contractors are held to the same safety procedures and are thoroughly trained prior to the beginning of projects.

Finally, in addition to PSEP's success from a safety perspective, environmental considerations are effectively considered and managed when implementing the program. The 41 projects included in this application had no violations or fines issued by any agencies. The PSEP Environmental Group works closely with the project teams to identify potential environmental issues early in the planning process and to develop mitigation strategies. For example, SoCalGas and SDG&E shared and transferred water used in pressure testing for reuse among multiple projects. This effort reduced the dependency on potable water (of particular importance with the drought conditions in Southern California) and also minimized waste.

V. PSEP HAS PRUDENTLY MANAGED RESOURCES CONSISTENT WITH THE VOLUME OF PSEP PROJECTS

A. PSEP Personnel

Through PSEP, SoCalGas and SDG&E have been tasked with expeditiously implementing the largest natural gas infrastructure enhancement plan in their history. There were no idle existing employees available to transition to PSEP without impacting

the immediate maintenance or construction activity and to ensure that the pipeline system and related equipment will be able to operate safely and efficiently for their service lives.")

our ability to safely and reliably maintain our pipeline system and remain in compliance with state and federal regulations.[23]

SoCalGas and SDG&E knew it would be difficult (if not impossible) to cost-effectively hire exclusively Company personnel in a timely manner to meet the Commission's directive that work be completed as soon as practicable. Furthermore, because PSEP is not a permanent program and will not become an ongoing part of how SoCalGas and SDG&E safely and reliably operate their system, eventually PSEP-dedicated Company personnel will need to be transitioned to other positions within SoCalGas and SDG&E.[24] As such, it was determined that the best method to implement PSEP was to augment SoCalGas and SDG&E's resources by engaging contractors, some with specialized skills working on large infrastructure projects, who could be quickly added or removed from PSEP depending on the needs of the organization. Table 1 below depicts the number of internal and external resources directly supporting PSEP at various points in time:

[23] SoCalGas and SDG&E normal operational staffing levels are established based on the expected annual amount of pipeline work – a level far below the level of work required to implement PSEP. Therefore, there was not additional resource capacity that could be utilized for PSEP. In addition, SoCalGas and SDG&E were concerned that drawing too many experienced employees from other SoCalGas and SDG&E departments would impact our ability to continue to safely and reliably maintain our pipeline system and maintain compliance with state and federal regulations.

[24] Nor were there a large pool of highly qualified engineers available to hire. The most expeditious, and in the long run, most cost effective choice was to hire contractors to perform the PSEP work.

Table 1

PSEP Resource Mix

	Internal Resources	External Resources[25]	Total	% Internal
6/14	216	275	491	44%
6/15	275	536	811	34%
12/15	287	490	777	37%
4/16	286	382	668	43%

In addition to augmenting internal resources with contractors, SoCalGas and SDG&E have actively pursued hiring additional internal resources for both engineering and non-engineering positions. SoCalGas and SDG&E's objective in staffing PSEP is to acquire personnel with the necessary skills and expertise to efficiently plan, execute, and oversee PSEP work while maintaining safe and reliable service to customers. The PSEP organization has retained SoCalGas, SDG&E, and external personnel needed to perform a wide range of project work activities including: project management, planning, engineering, logistics, purchasing, contracting, project cost and schedule controls, environmental monitoring, land rights acquisition, contractor oversight, quality assurance/quality control, and document management. SoCalGas and SDG&E continue to work to acquire experienced personnel from all sources: transferring and developing internal Company personnel, hiring external personnel, and engaging contractors. This is all being done in anticipation of internal Company personnel taking a more prominent role as PSEP matures. As of April 1, 2016, a total of 307 SoCalGas and SDG&E

[25] Does not include construction contractors.

PSEP positions have been hired into either new or replacement PSEP positions. Table 2 summarizes the results of these efforts:

Table 2

SoCalGas and SDG&E PSEP Hiring

	2012		2013		2014		2015		YTD 2016[26]		Total	
	New	Repl.	New	Repl.	New	Repl.	New	Repl.	New	Repl.	New	Repl.
Engineering (Eng.)	3	0	16	1	16	2	9	4	2	1	46	8
Eng. Ext. Hires	5	0	2	0	21	1	6	1	1	2	35	4
Non-Engineering (N/E)	15	0	33	0	62	10	17	7	1	5	128	22
N/E Ext. Hires	0	0	9	0	22	1	20	7	4	1	55	9
Total	23	0	60	1	121	14	52	19	8	9	264	43

While SoCalGas and SDG&E continue their efforts to hire internal resources, a program the size of PSEP will always require external resources to effectively execute.

In addition to those in the PSEP organization, SoCalGas and SDG&E personnel outside of the PSEP organization also provide support on an as-needed basis. Employees in the Transmission and Distribution Regions and Gas Engineering organizations provide project-specific support in areas such as customer impact analysis, engineering drawing review, tie-in operations, and construction.[27] Company resources in Human Resources, Pipeline Safety and Compliance, Customer Engagement, Media and Employee Relations, and Facilities also provide programmatic support for the PSEP PMO. Management positions authorized to charge to PSEP are approved by both PSEP and the appropriate operating department's leadership. As part of

[26] First Quarter 2016.

[27] In addition to support, SoCalGas and SDG&E employees do assist with project execution as appropriate. In order to meet the Commission's directive to complete PSEP "as soon as practicable," Region Operations initially managed a group of small projects before the PSEP group was fully established. Four of these projects are included in the application. Region Operations have the option to retain this work on a project-by-project basis with PSEP approval and oversight. However, the current plan is for SoCalGas and SDG&E to continue to transition these small projects to the PSEP organization in order to complete Phase 1A in 2018.

the approval process, an estimated roll-off date is agreed upon when the resources will no longer be required to support PSEP. These estimated dates are validated on an annual basis and updated as appropriate. On a monthly basis, each management employee is required to account for hours charged to PSEP by documenting the nature of the charges. The justification and the time charged are reviewed by PSEP and discrepancies are reconciled.

The resource recruitment and management processes described above have resulted in a PSEP organization that was prudently developed to execute PSEP and enhance system safety cost effectively and expeditiously.

B. PSEP's Ongoing Efforts to Minimize Project Execution Costs

i. PSEP has Implemented Efforts to Promote Reasonable and Market-Based Costs to Customers

Procurement of services (construction contractors, engineering providers, inspectors, surveyors, etc.) and materials is the largest individual category of PSEP expenditures. Approximately 75% of PSEP costs are for purchased services and materials. As such, an important aspect of PSEP is retaining capable vendors and contractors at reasonable rates. To promote the reasonableness of these costs, PSEP relies heavily on supply management techniques and practices to acquire materials and services at market rates. To provide safety enhancement to customers at reasonable and market-based costs, SoCalGas and SDG&E use reasonable selection processes, create reasonable incentives, and impose cost controls. PSEP maintains guidelines for the preparation, solicitation, evaluation, award and administration of contracts and subcontracts that supply PSEP with qualified and best value contractors, subcontractors, and vendors.

SoCalGas and SDG&E's sourcing objective is to utilize competition to achieve market-based rates. As such, the majority of PSEP agreements entered into for materials and services have been either competitively bid or were set at market-based rates stemming from previous competitive solicitations. In other words, in addition to individual bidding events, as appropriate, PSEP executes agreements by leveraging terms and conditions and rates from existing SoCalGas or SDG&E agreements; this avoids administrative costs, uses previously negotiated rates, and furthers the completion of work as soon as practicable. The above typically occurs through releases from a Master Service Agreement (MSA).[28] Releases from a MSA are used to authorize services and memorialize any commercial and technical terms for a specific scope of work, compensation schedule, and delivery/performance schedule in accordance with the terms and conditions of the MSA. For tracking purposes, these MSAs and releases are considered to be single sourced because a separate individual bidding event did not occur. Although tracked as single source, releases from MSA's that were implemented using market-based rates further promote cost reduction by avoiding logistical costs associated with separate bidding events. In these instances, SoCalGas and SDG&E are using previous efforts to competitively bid, vet, and negotiate contracts; promoting market-based rates, leveraging earlier efforts to competitively source vendors and contractors, and promoting cost effectiveness and expeditious execution of PSEP.

Approximately 98% of PSEP agreements with contractors and suppliers are either competitively bid or are through agreements that use market-based rates based on a recent competitive sourcing event.[29] This includes costs incurred to directly execute a PSEP project

[28] A Master Services Agreement is a contractual arrangement with a contractor/supplier that typically defines the broad terms, conditions, rates, and fees that are agreed to by both parties and governs all the work that will authorized under the MSA. Although an MSA contains general terms, typically there is a "release" that is more detailed to the task at hand, and that is executed for each project under each MSA.

[29] This figure was calculated through a review of PSEP agreements executed up to January of 2016.

and project support costs incurred to support PSEP execution more generally (as discussed in Chapter VII (Mejia) and VIII (Tran)).

Despite the benefits associated with competitively bidding contracts, there are circumstances when it is not possible or prudent to do so. In such instances, single or sole sourcing can be reasonable contracting options that help realize efficiencies, reduce administrative costs, and promote the completion of PSEP as soon as practicable. For example, because the duration of a typical competitive sourcing event is between 12 to 18 weeks depending on contract value and complexity, in order to get projects to construction in the early stages of PSEP as soon as practicable, construction support activities (e.g., inspection) were single sourced. In this instance, the inspection firm single sourced had the resource capability to meet our immediate need for this service.

ii. The Performance Partnership Program Further Enhances Construction Contractor Cost Effectiveness

As the volume of PSEP Phase 1A work increased, SoCalGas and SDG&E determined that it would be best to competitively bid bundles of construction work. Therefore, contract bundles, by area, were competitively bid, negotiated, and awarded through the Performance Partnership Program.[30]

The Performance Partner Program allows Performance Partners to enter into competitive bidding for batches of projects, as opposed to one at a time. This provides numerous benefits for SoCalGas and SDG&E: providing competitive market prices, avoiding administrative costs for successive individual bids, engaging construction contractors in longer term agreements for

[30] Work was split into different construction regions (Central Coast / North Coast, LA Basin, Desert, San Diego, and San Joaquin Valley). Four regions (Central Coast / North Coast, LA Basin, San Diego, and San Joaquin Valley) use a performance partner. One region (Desert) continues to competitively bid PSEP construction work.

numerous projects (which lowers costs by hiring a sustained workforce with less downtime and allowing contractors to work with the same internal engineering teams for a more collaborative effort),[31] and providing contractors an incentive to competitively bid for the work and agree to additional cost control mechanisms (since the winning bidder is awarded more than just one project). Although PSEP has been using Performance Partners, the PSEP organization retains the discretion to conduct competitive solicitations or to single source work to acquire contractors for any PSEP projects where it is determined that it may beneficial.[32]

Under the Performance Partner Program, each project worked on by a Performance Partner is subject to a target pricing risk/reward mechanism. This mechanism is based on establishing a target price agreed to by SoCalGas and SDG&E and the Performance Partner. Using this target price, the Performance Partner has a cost incentive to efficiently perform the project because it shares in both reduced and excess costs. The Performance Partner is not, however, entitled to any profits when costs exceed 20% of the target price.

SoCalGas and SDG&E, by virtue of the sharing mechanism, realize cost savings that would not exist under traditional competitively bid contracts. For the 17 projects included for cost recovery in this filing that were awarded to a construction contractor under the Performance Partner Program, a $3.9 million cost avoidance was realized when taking into account the difference between the negotiated target price and the final actual cost to SoCalGas and SDG&E.

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[31] These efforts also mitigate the risk of insufficient trade labor and supervisory resources (leading to direct cost savings through efficient dispersal and logistics of regional work) and better enable construction personnel to provide valuable engineering and design recommendations.

[32] For example, (1) in order to diversify the assignment of work (instead of limiting it to four construction partners); (2) as a separate tool to validate costs incurred by the performance partners (providing yet another rate by which to compare performance partner performance); and (3) allow other construction contractors who were not selected as performance partners the opportunity to bid on projects, which helps sustain their viability in the SoCalGas and SDG&E service territory.

The complete results of the sharing mechanism for the 17 projects included in this application are included in Attachment A.

In addition to the risk-reward mechanism, SoCalGas and SDG&E were also able to negotiate other incentive mechanisms to reduce costs to customers. These include: (1) overall caps on Performance Partner overheads; (2) individual project profit caps under the sharing mechanism; (3) negotiated annual profit caps based on total work completed (this resulted in an approximate $950,000 rebate after the first year of the contracts); (4) caps on the mark-up from third party subcontractors used by the performance partner; and (5) the ability to audit Performance Partner costs.

SoCalGas and SDG&E engaged KMPG to evaluate the results of the Performance Partnership Program and analyze the profit paid to a pipeline contractor using lump sum contracts awarded by competitive solicitation and the profit paid to the same contractor under the Performance Partner Program.[33] The Utilities asked this analysis to be performed to determine if there were verifiable cost savings and whether to continue with this approach. KPMG concluded that the Performance Partnership Program can result in greater customer benefits through reduced costs.

iii. Materials

PSEP materials are acquired in a manner designed to minimize costs and maximize timely delivery. Materials and equipment are procured according to PSEP standards and practices. In an effort to provide the lowest reasonable cost, each specific project may have different execution strategies. Generally, materials and equipment are purchased by an agent for SoCalGas or SDG&E, with payment made through the existing SoCalGas or SDG&E systems.

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[33] *See* PSEP Pipeline Construction Contractor Profit Analysis (Attachment B).

Further, to take advantage of previous efforts to vet and engage vendors, SoCalGas and SDG&E's Approved Manufacturers List (AML) is utilized.[34]

Where possible, PSEP acquires materials by aggregating material needs from multiple projects thereby making periodic buys for larger quantities of materials. These efforts better enable SoCalGas and SDG&E to obtain favorable pricing. Project-specific buys are also done to account for specific design parameters. Generally, for project-specific buys, multiple buys are executed at each major design phase to address time constraints and reduce costs. For example, long lead time items are identified early for sourcing. As appropriate, items may be transferred between projects to reduce last minute buys and shipping costs. Regardless of the type of order, material bids are designed to obtain multiple quotes for the best pricing options, promoting work with select firms for efficiency of process, and encourage the development of local resources and sourcing.

Due to the sheer volume of projects, PSEP requires a high amount of warehouse space to store materials. Two separate material yards were established in Fontana[35] and Bakersfield. These locations provide centralized hubs to serve as receipt points for material shipments and staging areas for project materials. The PSEP Supply Management team accumulates individual project material requirements and, where possible, executes bulk purchases through a competitive solicitation process. This provides better pricing through economies of scale and avoids multiple purchases with duplicative transactional steps. Once received, the bulk material is staged by project for delivery to the job site.

[34] Sourcing new suppliers is considered when the current AML providers cannot support the project needs or it is determined that additional competition would be cost advantageous.
[35] The Fontana location was closed in March of 2016 as PSEP work is becoming more concentrated in the Northern portion of the SoCalGas Service Territory.

iv. PSEP's Ongoing Efforts to Maintain Market-Based Costs

As market conditions change (e.g., slowdown in statewide and nationwide construction activity) or as PSEP develops new market strategies (e.g., not-to-exceed bids for certain categories of work) PSEP has gone back out to the market to negotiate lower costs. Within the last year, PSEP has re-bid or renegotiated contracts with providers of the following functions: inspectors, engineering design, survey, environmental services, warehousing. For these services, it was our opinion that the decrease in the price of oil had decreased the market for these services. In other words, since the demand for their services has likely decreased, there was an opportunity to calibrate costs to current (less expensive) market conditions. These efforts have resulted in cost reductions.

v. Other Cost Avoidance Efforts

In addition to the successful efforts to avoid costs through project scope validation, the PSEP project teams also look for ways to avoid costs in the design and construction phases. The teams exercise diligence (1) during the planning and detailed design phases to find the least cost approach to design the pressure test, replacement, or valve work; (2) by negotiating with permit agencies and land owners to avoid costly permit conditions or unreasonable land acquisition costs; and (3) by minimizing the cost impact of design conflicts and scope changes when unforeseen conditions arise during construction.

Finally, the cost savings efforts for the PSEP program were not limited to contracting for traditional materials and services. For example, by placing PSEP Professional Liability insurance ourselves, we were able to reduce the Professional Liability insurance placement by nearly $2 million (when compared to our project management firm placing it).[36] Services such

[36] Costs for Professional Liability insurance is collected through the PSEP insurance overhead.

as engineering, design, and agency construction management exposures were covered as a result of this placement, providing important protections to customers and increasing competition for services being rendered. Additionally, after we reduced the mileage through records review by more than half, we further reduced the insurance premium by arguing that the insurance carrier's risk was reduced.

C. PSEP's Cost Tracking, Controls, and Management Practices Prudently Manage Project Costs

As part of the cost management effort, it is important to track and categorize the PSEP costs that have been incurred. Generally, project-specific costs are charged to their respective project accounts. Costs that cannot be attributed to a specific PSEP project are charged to a non-project specific account, based on the related activity and support function.[37] Through cost tracking and categorization, SoCalGas and SDG&E document that costs are appropriately categorized and that the recorded costs were incurred to directly contribute to PSEP implementation and execution.

SoCalGas and SDG&E track costs by Work Order Authorization (WOA). The general function of a WOA is to track costs associated with planning and execution of a specific project. To properly track costs to the appropriate category and project, projects and cost categories are assigned a unique internal order number that is used to track costs associated with that project or activity to a WOA. Additionally, SoCalGas and SDG&E implemented procedures to verify the accuracy of costs. This includes verifying that billing rates are correct, reviewing time sheets for hours worked, and reviewing other supporting documentation for accuracy. Once the information on invoices is verified, the invoice reviewer forwards the invoices to the project

[37] *See* Chapter VIII (Tran).

managers to confirm that the correct labor hours were worked on the project and the billed labor rates, and any additional expenses, are within the terms of the contract.

VI. PSEP ENCOUNTERS EXTERNAL OBSTACLES THAT DRIVE COSTS INCREASES

Pipeline and valve projects are complex and require detailed orchestration. Many things have to line up to begin construction. Many of the factors that determine when SoCalGas and SDG&E can begin construction are not in the direct control of SoCalGas and SDG&E. Restrictions on when construction can occur must be determined and adhered to (cities may have moratoriums during heavy traffic periods; we may need to work around a large customer's planned outage or low usage period; or Gas Control may have restrictions of when the pipeline can be taken out of service). Permits, land rights, and materials have to be acquired. Availability of construction contractors, inspectors, specialty equipment, construction oversight personnel, and regional operations personnel must be considered. As a result, it is not uncommon for Project Teams to be engaged in hurried efforts to acquire a permit or land right or material, or to reschedule the construction start date due to the planned construction crew being delayed from the completing another project.

Despite SoCalGas and SDG&E's reasonable efforts to avoid and reduce costs, external factors can impact project scope, cost, and schedule. As a result, early project estimates based on preliminary project planning and engineering design usually will not reflect the reasonable costs ultimately incurred to complete the work. The following is a description of the key external factors impacting projects.

A. <u>Permitting and Temporary Land Rights Acquisition</u>

In the area of construction, there is a significant difference between projects that are completely or mostly completed on private land ("behind the fence") and those that are "linear projects" where the owner doesn't own the land. In the latter, since the owner does not own the land, various permits and rights must be obtained for construction to occur. PSEP pipeline and valve projects are primarily linear projects located in franchised rights of way (streets) but are also located on private and federal land. PSEP projects are also located in all areas of the SoCalGas and SDG&E service territory, which leads to a wide array of geographical diversity and challenges. These varying locations results in the need to acquire numerous permits and negotiate with private landowners. Each of the various types of permits or individual landowners brings various challenges to projects but generally the issues have centered on the time to obtain permits, the increasing stringency of permit requirements, and cost and time to negotiate temporary or permanent land rights. Some projects do not require extensive permitting if located within existing SoCalGas and SDG&E facilities. Others, depending on the location of the projects, may require multiple additional permits, from environmental (water, wildlife, cultural, Caltrans, etc.).[38] At a minimum, PSEP projects require a permit from the municipal agency where the replacement or hydrotest is being executed before a project can commence construction. To illustrate, approximately 140 permits and 90 land use agreements were obtained for the 41 projects included in this application.

When working in the streets different types of permits are needed. Typically, an excavation permit is needed from the local jurisdiction the purpose of which is to establish work times, allowable length of the project, dates of when work may not be performed during heavy traffic conditions ("holiday moratoriums"), etc. Permits are also needed for traffic control to

[38] Environmental and cultural permitting is also challenging in various project locations. Some projects require species, cultural or other types of monitors to excavate and perform construction work. Each of these monitors adds cost and potential schedule delays to each project. Fish and Wildlife or other Federal land permits are required in addition for some projects. These permit groups have long lead times and can restrict projects to certain schedules.

determine arrow boards, delineation, number of lanes that may be closed, etc. Further, projects may transgress more than one jurisdiction – city streets, county streets, Caltrans jurisdiction on freeway underpass/crossing. The different agencies all require permits and each has their own preferences. For instance, in a few cases one agency required night work while the other required work only during the day, which causes issues where the two jurisdictions meet. They may have differing preferences on how to handle environmental and cultural resources issues that may arise from disturbing the soil under the pavement.

In addition to the number of permits, agency staffing levels have not increased at a commensurate level to the volume of permits being requested. Therefore, the length of time required to obtain even the most rudimentary permit has increased. For example, depending on the complexity of the permit and the permitting municipality or agency, encroachment and traffic control permits can take anywhere from two weeks to nine months to obtain. Additionally, smaller cities are typically not staffed adequately to review the large design packages produced by PSEP for larger projects within their borders, which adds to the review time. Although SoCalGas and SDG&E factor in anticipated permit processing time in their project planning process, unanticipated delays occur, especially when there are resource constraints at the agencies.

Permitting agencies are also placing greater restrictions and additional requirements on SoCalGas and SDG&E on issued permits. One example of this is seen in the limitation on work hours. For example, some permits only allow street work to begin at 9:00 am and be complete prior to 3:30 pm. This results in only four to five hours of productive work for crews. It takes a part of each day to setup traffic control and remove road plates before the day's construction activities can commence. At the end of the day, time is needed to plate the excavations and remove traffic control. Compared to crews with approved 10-hour work windows, these shortened work days can double the time for construction of a project. Another example of permitting restrictions is the time of year for project construction. Some of the pipe segments are located in resort areas, where PSEP work is severely restricted or forbidden during the peak season. Many municipalities also limit or prohibit construction activities along major thoroughfares over holiday seasons, with moratoriums between Thanksgiving and New Year's Day common.

The length of active construction activity allowed can also impact productivity. Some agencies restrict this length to only 500 feet at a time. This means the activities are taking place very close to each other in a congested workspace which reduces productivity as the length of time required to complete a given task increases. When agencies allow lengths nearer 1,000 feet, concurrent construction activities are not as congested.

Permitting agencies' requirements can also change project scope which may cause a redesign or other drawing revision. This results in delays and added cost. Pavement repairs are often extended to full lane repairs or overlays. These add to the paving costs. Specialized pavement types, such as rubberized asphalt have been required for repairs, again raising restoration costs.

Finally, the design of some pipeline and valve projects may require the acquisition of permanent rights from private landowners. Almost all PSEP projects require some temporary space needs for the storage of equipment and material as well as office space.[39] Temporary and permanent land rights are acquired from the owners. These landowners may not be local and can

[39] To support the construction in the streets, temporary land is needed for the construction yard – place to store equipment, materials, traffic plates, trailers, etc. for the duration of the project. Additionally, space is needed for temporary storage of water tanks, pumps and filtration equipment which must be acquired.

be difficult to reach. Some owners initially demand large fees for easements or temporary use agreements and it takes longer to negotiate. Some commercial or industrial property owners may even impose their own work restrictions or requirements. Private land negotiations can be challenging and may impact project schedule.

In an attempt to avoid delays, the PSEP Land Services Team, a dedicated team for permitting and land right acquisition, was formed in mid-2014 to assist with these efforts. The team is an important asset to the program to monitor permit activities and assist with land negotiations. One of the early initiatives of the team was to improve the quality of the permit package submissions. This leads to less rejections of the initial application by the permitting agencies and reduced overall processing time. The PSEP Land Services Team works closely with SoCalGas and SDG&E Regional Public Affairs and the PSEP Community Outreach Teams. These efforts have assisted in resolving lingering issues that delay the issuance of permits and promote the issuance of permits in a timely manner. For example, permit review with a city in which PSEP had multiple projects was taking over nine months due to backlogs and lack of resources. The issue was elevated to city leadership and a new process was developed to ensure that one team is responsible for the review of utility plan submittals.

B. Construction Unknowns

Despite efforts in the planning and engineering design phase, unforeseen factors encountered during construction may increase the complexity of projects and cause projects to take longer than planned. For example, it is not uncommon to discover substructures that were not on maps or in records during excavation. This is particularly true for older areas because requirements for substructure recordation were not as stringent as today. Additionally, governmental records may have been lost over the years. Unidentified substructures usually result in pipeline routing changes. Unanticipated soil changes (i.e. loose sandy soil rather than more cohesive soil) may require a change in the excavation or shoring method. Finally, coordination with other utilities can sometimes delay project schedules. For example, for some valve projects, new communications and electricity lines are required when a valve is automated and despite scheduling in advance, delays are often encountered by electric and communication utilities in the completion of their portion of the project.

C. Material Availability

Given the unprecedented level of pipeline work, not only at SoCalGas and SDG&E but at other California utilities, material availability has been an issue that has impacted cost and schedule. SoCalGas and SDG&E have purchased, when appropriate, bulk quantities of commonly used pipe fittings and pipe in order to have adequate material available for projects. Bulk purchases result in better pricing as opposed to purchasing material on a project-specific basis. However, there are certain materials that are not bought “off the shelf” but must be made to order or modified to fit conditions. Examples are valves with extensions, vaults to house equipment underground, and instrument cabinets. Manufacturing delays occur due to capacity limitations caused by increased demand for pipeline material at a regional and national level. To determine whether ordered materials meet company specifications many items require inspection. Items that do not meet specifications need to be repaired or new items acquired. This causes extra time that at times can be the cause of a delay of construction start.

D. Capacity Impacts

Although customer and capacity impacts are vetted during Stage 3 of the Seven Stage Review process described earlier in my testimony, unanticipated system or customer issues may be encountered that could potentially delay a project. For example, if a project as planned requires a pipeline segment to be taken out of service for a period of time, and a different pipeline previously assumed to be available to serve customers is taken out of service, a project may be delayed or a previously unplanned provision of an alternate supply (CNG/LNG) to serve customers may be required.

E. <u>The Regulatory Process</u>

Reasonableness reviews require additional steps to document costs not normally required. In addition to the compliance related documentation required of SoCalGas and SDG&E pipeline work, the extensive supporting details contained in the workpapers associated with this application is not normally generated to the level of detail presented here. This application encompasses twelve chapters and dozens of workpapers. The detail is intended to provide the Commission with a description of activities undertaken and decisions made at each stage of the Seven Stage Review process as well as an explanation of the reasonableness of the costs incurred. This level of detail is included based on feedback received from parties in A.14-12-06 and the desire of SoCalGas and SDG&E to be responsive to that feedback and promote expeditiously resolution of PSEP after-the-fact reasonableness reviews. The information and its creation, however, is time intensive and costly.

VII. PSEP HAS BEEN MANAGED REASONABLY AND PRUDENTLY AND COSTS SHOULD BE JUDGED BASED ON SOCALGAS AND SDG&E'S ACTIONS AND RESULTS

In assessing the reasonableness of the incurred costs, the Commission must determine whether SoCalGas and SDG&E incurred the costs necessary to enhance system safety reasonably and consistent with a reasonable manager. To meet this standard, "[t]he act of the utility should comport with what a reasonable manager of sufficient education, training, experience and skills using the tools and knowledge at his disposal would do when faced with a need to make a decision and act."[40] In approving SoCalGas and SDG&E's PSEP, the

[40] D.90-09-088, mimeo., at 16.

Commission noted: "This is not a perfection standard: it is a standard of care that demonstrates all actions were well planned, properly supervised, and all necessary records are retained."[41] In other words, SoCalGas and SDG&E's must demonstrate that their safety enhancement actions and associated costs were reasonable based on the facts and circumstances that were known or should have been known when the decision was made or action taken. As explained at length in this application, the answer is clearly yes.

As discussed above, PSEP projects may experience numerous unknowns: permit approval times; land acquisition times; permit approval conditions (that can greatly affect productivity and cause much higher costs); material delays; and subsurface facilities or conditions that cannot be estimated or known until after construction is underway. As a result of these and other conditions discussed in workpapers, there have been cost variances experienced during construction.

The cost variances encountered in the execution of PSEP are in line with other public and private global organizations that manage large construction projects. The 2015 KPMG Global Construction Survey (Attachment C) interviewed executives from over 100 organizations on a wide range of project related topics, including planning and financial forecasting, risk and project management, and contractor management among others. The survey indicated:

- "Looking back over the past 3 years, fewer than one-third of all respondents projects managed to come within 10 percent of the planned budget, with the energy and natural resources, and especially the public sector, performing considerably worse than other industries."[42]

[41] D.14-06-007, mimeo., at 12.

[42] KPMG Global Construction Survey 2015, pg. 17 (Attachment C).

- "…just a quarter of construction projects come within 10% of their original deadlines…"[43]
- "…owners are heavily dependent upon capable project management teams that understand engineering and construction, project management principles and practices…."[44]
- "44% of respondents struggle to attract qualified craft labor and 45% cite a lack of planners and project managers."[45]

Consistent with our peers and other reasonable managers, SoCalGas and SDG&E have experienced similar variances and constraints in executing PSEP.

Furthermore, consistent with the reasonable manager standard, the Commission should be cognizant of what SoCalGas and SDG&E knew during the initiation of these projects. As mentioned, all of the projects presented for review and recovery in this Application were initiated prior to the issuance of D.14-06-007. Prior to D.14-06-007, the extent of the after-the-fact review process was unclear and as such our focus was on executing safety enhancement work reasonably, prudently, and as soon as practicable – not engaging in detailed estimating efforts or attempting to estimate or forecast multiple variations. Doing so would have slowed down PSEP work. The purpose of our preliminary estimates was to guide decision making and to implement PSEP as soon as practicable. That being noted, ongoing enhancements of the cost estimating tool used by SoCalGas and SDG&E PSEP have taken place and will lead to more refined estimates. A dedicated cost estimating team has been established and experienced cost estimating professionals were hired. While these process improvements should yield more accurate estimates, scope changes beyond our control will continue to result in cost variances. As such, the Commission should look to the reasonableness of SoCalGas and SDG&E's efforts

[43] KMPG Global Construction Survey, 2015, pg. 18 (Attachment C).
[44] KMPG Global Construction Survey 2015, pg. 8 (Attachment C).
[45] KMPG Global Construction Survey 2015, pg. 9 (Attachment C).

to avoid and control costs, while enhancing system safety, not the accuracy of a preliminary estimate.

VIII. CONCLUSION

SoCalGas and SDG&E should be authorized to fully recover the costs presented in this application minus disallowances acknowledged in Chapter III (Phillips) and Chapter V (Mejia). The costs were incurred to complete work that was mandated by the Commission and State law, SoCalGas and SDG&E activities comply with Commission decisions and guidance, and SoCalGas and SDG&E acted as reasonable managers in executing PSEP work. In so doing, SoCalGas and SDG&E have been executing PSEP consistent with its stated objectives:

- <u>Enhance public safety</u>: PSEP projects have been completed successfully and consistent with applicable rules, regulations, laws, and SoCalGas and SDG&E's internal policies and procedures.
- <u>Comply with the Commission's directives</u>: PSEP efforts have been consistent with Commission instructions to proceed "as soon as practicable" and have worked with the SED pursuant to their oversight role.
- <u>Minimize customer impacts</u>: Projects were completed while maintaining service to core customers and with minimal planned outages for commercial and industrial customers.
- <u>Maximize the cost-effectiveness of safety investment</u>: SoCalGas and SDG&E reasonably avoid costs, obtain market-based contractor and material rates, use a prudent amount of internal and external resources, and prudently design, engineer, and execute PSEP projects.

The Commission should find that SoCalGas and SDG&E have executed PSEP prudently and have implemented and executed PSEP consistent with the requirements of D.14-06-007. The costs presented for review and recovery in this application are reasonable and the associated revenue requirements submitted for recovery should be fully recovered in rates.

This concludes my prepared Direct Testimony.

IX. WITNESS QUALIFICATIONS

My name is Richard D. Phillips. I have been employed by SoCalGas since 1978. I have held Director level positions in Engineering, Supply Management, Gas Distribution, Electric Distribution, Customer Services, IT, and Storage as well as a manager position in gas transmission pipeline services.

My current position is Senior Director, Pipeline Safety Enhancement Program.

I have a Bachelor's degree in Engineering from University of California, Irvine, cum laude. I am a registered Professional Engineer in California. I have a certificate in Executive Management from the University of Michigan and a certificate in Finance for Executives from the University of Chicago. I was a member of the Pipeline Research Council International.

I have previously testified before this Commission.

ATTACHMENT A

PERFORMANCE PARTNER COST AVOIDANCE SUMMARY

ATTACHMENT A
PERFORMANCE PARTNER COST AVOIDANCE SUMMARY

Line	Cost W/O Performance Partner Program	Cost Under Performance Partner Program	Cost Avoidance
1005	$ 1,986,714	$ 1,759,646	$ (227,068)
1011	$ 844,783	$ 776,933	$ (67,850)
1015 North	$ 1,193,705	$ 1,046,800	$ (146,905)
1015 South	$ 993,898	$ 978,833	$ (15,065)
2000W Sec 1	$ 3,013,207	$ 2,774,114	$ (239,093)
2000W Sec 2	$ 2,722,022	$ 2,419,047	$ (302,975)
2000W Sec 3	$ 3,624,991	$ 3,244,648	$ (380,343)
2003 Sec 1	$ 1,172,862	$ 1,157,402	$ (15,460)
2003 Sec 3	$ 1,600,268	$ 1,591,796	$ (8,472)
2003 Sec 4	$ 716,814	$ 460,442	$ (256,372)
33-120 Section 2	$ 3,377,997	$ 3,256,275	$ (121,722)
36-9-09 North Sec 2B	$ 1,225,184	$ 1,216,340	$ (8,844)
36-9-09 North Sec 6A	$ 1,337,590	$ 1,013,014	$ (324,576)
406 Secs 2,2A	$ 1,210,426	$ 1,166,142	$ (44,284)
406 Sec 1	$ 1,291,027	$ 1,287,930	$ (3,097)
406 Sec 5	$ 662,139	$ 596,967	$ (65,172)
38-539	$ 8,001,504	$ 7,925,347	$ (76,157)
PDR Storage Phase 5	$ 3,654,962	$ 2,364,057	$ (1,290,905)
Pixley Valve	$ 194,836	$ 172,077	$ (22,759)
49-14	$ 1,656,966	$ 1,635,965	$ (21,001)
TOTAL	**$ 40,481,895**	**$ 36,843,774**	**$ (3,638,121)**
Note: Cost w/o Perf Partner Program signifies what the cost would have been absent the Perf Partner sharing mechanism.			
- The Final Total Cost exceeded the Final Target Price for the following projects, the amount of the risk payment paid by the Contractor representing their share of the overage is shown as a cost avoidance.			
			Cost Avoidance
2001W-B Sec 10			$ (99,655)
2001W-B Sec 11			$ (90,299)
2001W-B Sec 14			$ (8,132)
407 South			$ (2,295)
SGV Valve			$ (100,843)
Victoria Valve			$ (1,649)
TOTAL RISK PAYMENTS			**$ (302,873)**
GRAND TOTAL COST AVOIDANCE FOR PERFORMANCE PARTNER PROJECTS INCLUDED IN THIS FILING			**$ (3,940,994)**
Additional Cost Avoidance - Rebate paid by Contractor based on total spend*			**$ (949,137)**
*Note - rebate is based on all projects work by Contractor, including some not included in this Application.			
Rebate is applied as an offset to Construction General Management and Administrative costs (GMA)			
not on a project level.			

ATTACHMENT B

SOUTHERN CALIFORNIA GAS COMPANY
PSEP PIPELINE CONSTRUCTION
CONTRACTOR PROFIT ANALYSIS
AUGUST 11, 2015

KPMG

cutting through complexity

Southern California Gas Company

PSEP Pipeline Construction Contractor Profit Analysis

August 11, 2015

Contents

1. Executive Summary

KPMG LLP (KPMG, we, or our) was retained by Southern California Gas Company (SoCalGas) to perform a Pipeline Safetey Enhancement Program (PSEP) Pipeline Contractor Profit Analysis in order to assist SoCalGas' counsel with the assessment and comparison of profit paid to a pipeline contractor using lump sum (LS) contracts and cost based PSEP Performance Partnership Construction Services Agreement (Performance Partner) contracts. SoCalGas judgementally selected a PSEP contractor to be assessed.

KPMG performed project profit analysis at the selected contrator's office from June 22, 2015 through June 25, 2015.

Based on the terms and conditions of the PSEP cost based Performance Partner contracts and our analysis of profit paid to the selected contractor (Contractor) for lump sum contracts, it appears that the Contractor's lump sum projects are more profitable on average than PSEP cost based Performance Partner contracts. The contractor provided KPMG a list of 54 lump sum projects that were either completed & closed or were 95% percent complete for our analysis. KPMG judgmentally selected a sample of six lump sum projects including both gas transmission and distribution projects. Table 1 below summarizes the six projects assessed and reflects the Contractor's profit for each.

Table 1: Summary of six 2013-2014 Lump Sum Projects

Selection #	Final Contract Price	Final Job Cost Amount	Contractor's Profit Calculation	Adjusted Profit Calculation[1]
1	$ 22,983,351	$ 17,003,705	26.0%	21.9%
2	$ 1,091,680	$ 1,027,698	5.9%	1.3%
3	$ 9,953,474	$ 8,815,077	11.4%	6.1%
4	$ 2,723,002	$ 1,228,844	54.9%	52.6%
5	$ 7,049,162	$ 6,379,647	9.5%	5.6%
6	$ 2,776,522	$ 1,782,555	35.8%	32.7%
Total	**$46,577,191**	**$36,237,526**	**23.9%**	**20.0%**

[1]The adjusted profit calculation column includes project costs that were either increased or decreased in order to align with actual labor burden or overhead costs from the Contractor's PSEP cost based Performance Partner contract.

KPMG then adjusted the profit calculations for all six samples and applied the results to all 54 projects to obtain an adjusted average profit. Upon applying the adjusted profit calculation to all 54 projects, the average profit calculated was 23.3%. The results of the profit analysis are displayed below in Table 2.

Table 2: Average Profit Analysis Results

Based on 54 Projects	Contractor Average Profit Calculation	Adjusted Average Profit Calculation	PSEP Max Profit	LS Profit Greater PSEP Profit?
Average	**27.2%**	**23.3%**	**7%**	**Yes**

Based on our review and comparison of job cost accounting for the Contractor's lump sum and cost based Performance Partner contracts, we did not find any material differences between the cost tracking reports. We were also able to verify that all six lump sum projects were competitively bid and accounted for in a similar manner to the PSEP projects.

2. Scope of Work

KPMG is currently under contract with SoCalGas to perform routine contract cost compliance assessments on their PSEP cost based Performance Partner contracts with each of their vendors and has also been retained by SoCalGas to perform this analysis which includes an assessment and comparison of the selected contractor's profit on a sample of lump sum projects. The following is a summary of the approach for our analysis:

I. Judgmentally select a sample of 6 lump sum projects (out of 54 lump sum projects delivered by the Contractor). Request project cost reports, final payment application and payment ledger from the Contractor.

II. Reconcile the cost reports to the terms of the PSEP cost based Performance Partner contracts.

III. After reconciling adjustments are made to the job costs, calculate the realized profit on the sampled projects.

IV. Using the reconciling adjustment factors for the sampled projects, apply the applicable adjustments to the remaining 48 projects. Calculate the average profit for the 54 projects.

V. Summarize work performed, reconciling adjustments, and comparison of profitability of PSEP cost based Performance Partner contracts to lump sum contracts.

3. Summary of Analysis

3.1 Lump Sum (LS) vs PSEP Cost Tracking

LS project costs were tracked identically to PSEP project costs. The six sampled projects had the same cost types as the PSEP cost based Performance Partner projects tracked in their job cost reports. Table 3 below summarizes the definition of each cost type.

Table 3: Contractor's Cost Type Definitions

Cost Type	General Description	Detailed Description	Rolls Up
1	Labor	Labor Wages (Includes Admin paid time off) and craft subsistence)	Labor
2	Burden	Burden Labor (Craft fringes benefits plus burdens on Contractor's taxable labor costs)	Labor
3	Per Diem	Non-collective bargaining agreement allowances paid to craft employees or Admin employees through expense checks.	Labor
4	Subcontracts	Subcontracts that run through Contracts Administration group.	Subs
5	Contract Labor, Continuing Services Agreement, and Operated Equipment	Contract labor is labor performed on a project by a third party, CSA allows for third parties to perform labor not considered to be part of the permanent work. Operated equipment is any third party that provides Owner/Operated labor and equipment on site.	Subs
6	Materials	Permanent Plant Materials purchased for the project.	Materials
7	Sales Tax	Sales or Use Tax on materials or rental equipment purchased for the project. Does not include sales tax on receipts included in expense reports.	Materials
8	Miscellaneous	Consumables or materials that will not remain at site.	Other
9	Rented Equipment	Third party rented equipment that requires fuel.	Equipment
10	Rented Equipment (Non-Fueled)	Third party rented equipment that does not require fuel.	Equipment
11	Contractor Equipment	Contractor Owned Equipment.	Equipment

3.2 Lump Sum (LS), PSEP and KPMG Calculated Burdens & Overhead

Upon review of burden in the LS job costs, the percentages utilized to obtain the burden costs were 41% for both Union and Non-Union labor; however these burden costs were not the Contractor's actual burden. Similar to the PSEP contracts, the burden percentages comprised of payroll taxes, insurance, consumables, supervision and miscellaneous. KPMG calculated the Contractor's actual burden based on a 2013 program and obtained 28.71% direct union burden, 20.55% indirect non-union burden. The actual calculated burden percentages have been utilized to adjust the Contractor's job costs for the six samples selected. Since the calculated actual burden rates are lower than the burdens utilized by the Contractor in the job costs, the adjusted job cost amounts are lower.

The Final Job Cost Amount for the 54 projects the Contractor provided do not include overhead costs. KPMG calculated the Contractor's actual overhead based on a 2013 program and obtained an 8.99% overhead percentage. KPMG utilized the actual overhead percentage of 8.99% in its calculations.

3.3 Lump Sum Job Costs Reconciliations

To reconcile the costs of the sampled reports to the PSEP cost based Performance Partner contracts (KPMG's calculated actual burden and overhead percentage), KPMG isolated Labor Cost and discounted Burden amounts from Burden Cost. Next, KPMG calculated the 28.71% direct union burden and 20.55% indirect non-union burden from the Labor Cost amounts, accordingly. Lastly, the 8.99% overhead was added to the subtotal job cost amount to then obtain the adjusted profit for the project. Once these steps were completed for all six projects independently, the profit percentages were averaged and compared to the Contractor's profit calculation [Table 4]. The difference of 3.88% was then applied to all 54 projects to obtain their adjusted profit calculation and then averaged once more to obtain the adjusted average profit calculation.

Table 4: Profit Calculations from Sampled six Lump Sum Contractor's Projects

Selection #	Final Contract Price	Final Job Cost Amount	Contractor Profit Calculation	Adjusted Profit Calculation
1	$ 22,983,351	$ 17,003,705	26.0%	21.9%
2	$ 1,091,680	$ 1,027,698	5.9%	1.3%
3	$ 9,953,474	$ 8,815,077	11.4%	6.1%
4	$ 2,723,002	$ 1,228,844	54.9%	52.6%
5	$ 7,049,162	$ 6,379,647	9.5%	5.6%
6	$ 2,776,522	$ 1,782,555	35.8%	32.7%
Total	**$46,577,191**	**$36,237,526**	**23.9%**	**20.0%**
Profit Difference between the Contractor and KPMG			0%	3.88%

3.4 Summary of Results

Upon applying the adjusted profit calculation to all 54 projects, the average profit calculated was 23.3%. This average profit of 23.3% is greater than the maximum 7% profit permitted to the Contractor per year from the PSEP Schedule A; hence it appears that lump sum projects result in greater construction contractor profits, on average, than PSEP cost based Performance Partner contracts. The results of the profit analysis are displayed below in Table 5.

Table 5: Average Profit Analysis Results

Based on 54 Projects	Contractor Average Profit Calculation	Adjusted Average Profit Calculation	PSEP Max Profit	LS Profit Greater PSEP Profit?
Average	**27.2%**	**23.3%**	**7%**	**Yes**

ATTACHMENT C

KPMG
CLIMBING THE CURVE
2015 Global Construction Project Owner’s Survey

KPMG

cutting through complexity

GLOBAL CONSTRUCTION SURVEY 2015

Climbing the curve

2015 Global Construction Project Owner's Survey

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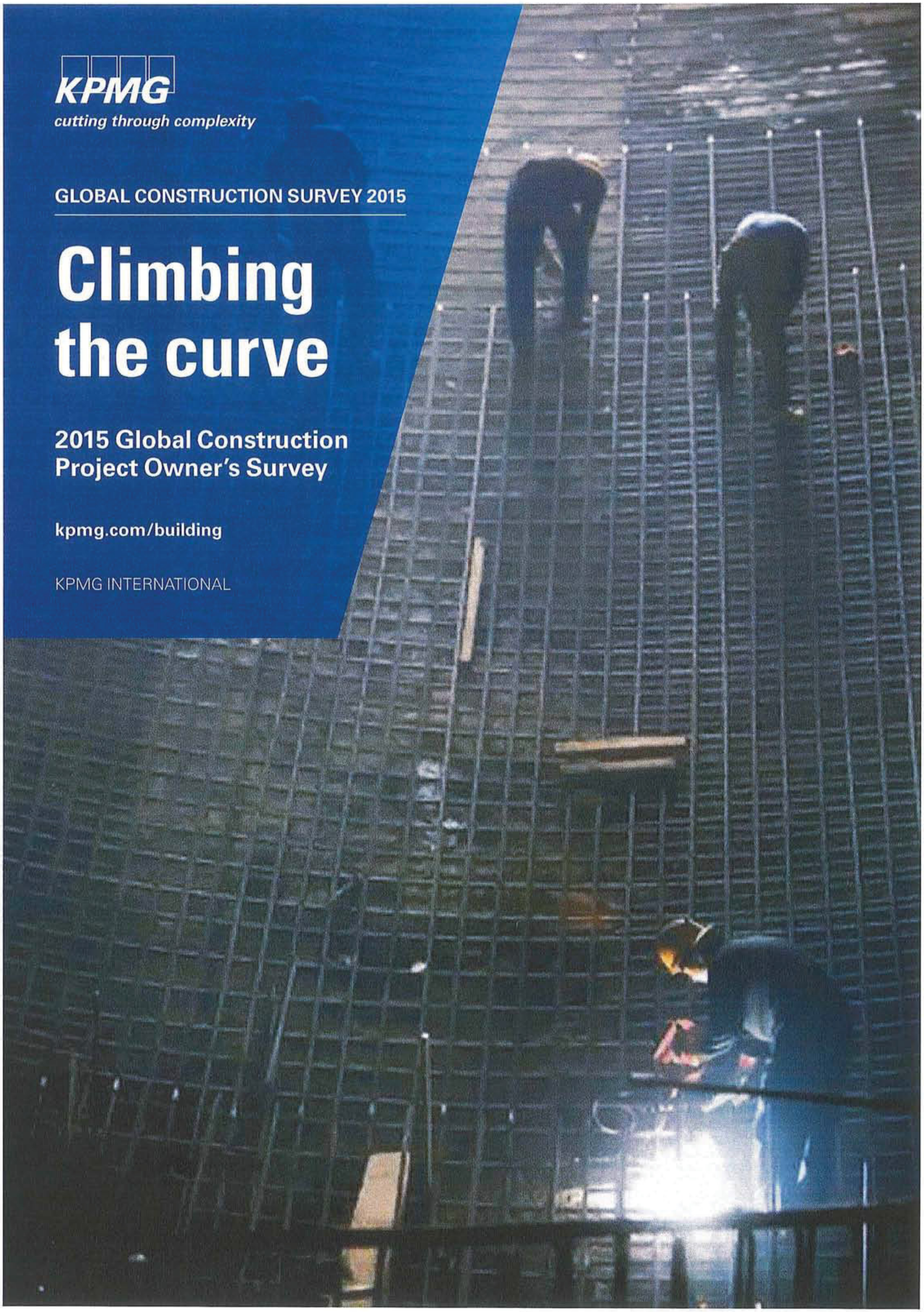

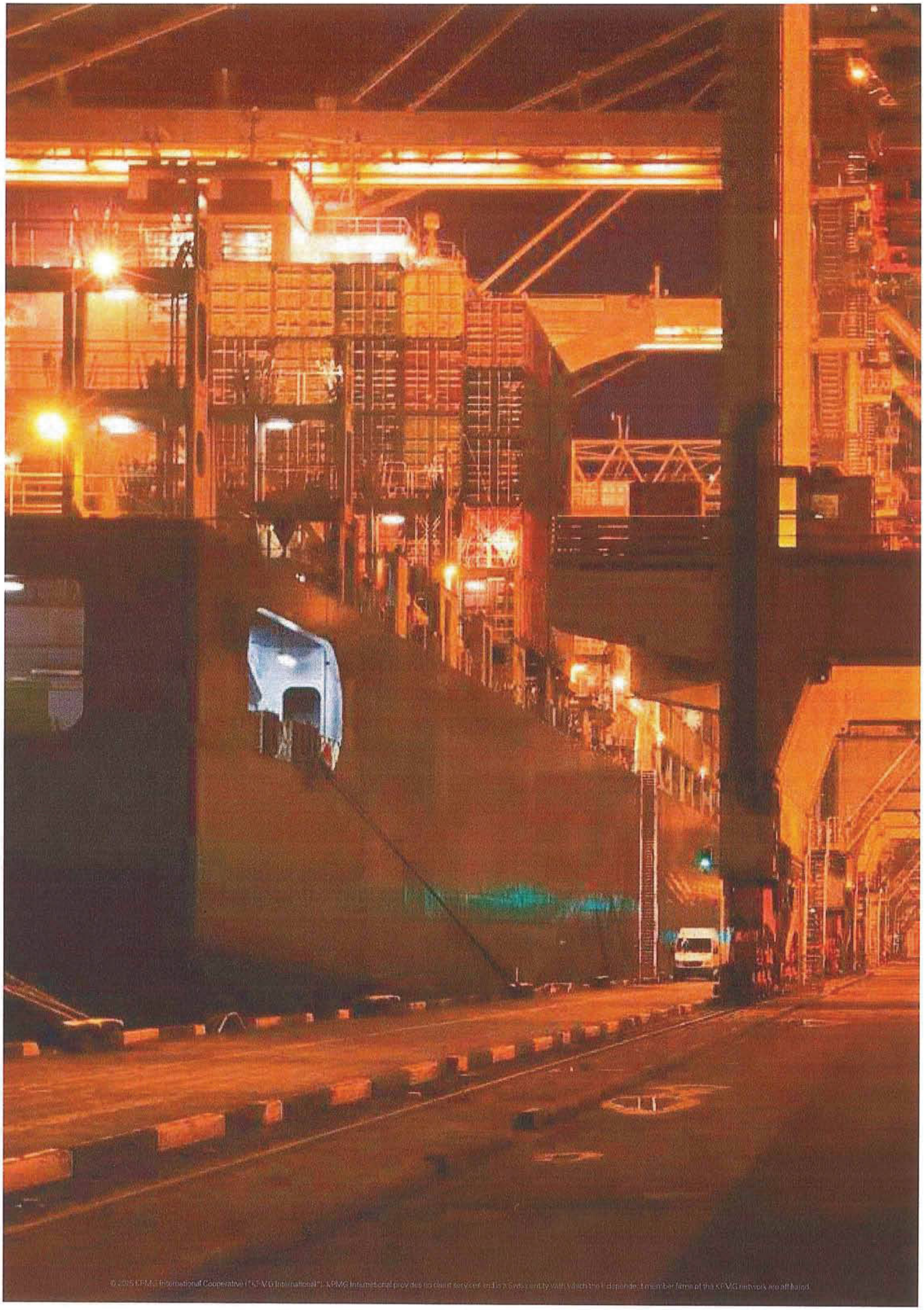

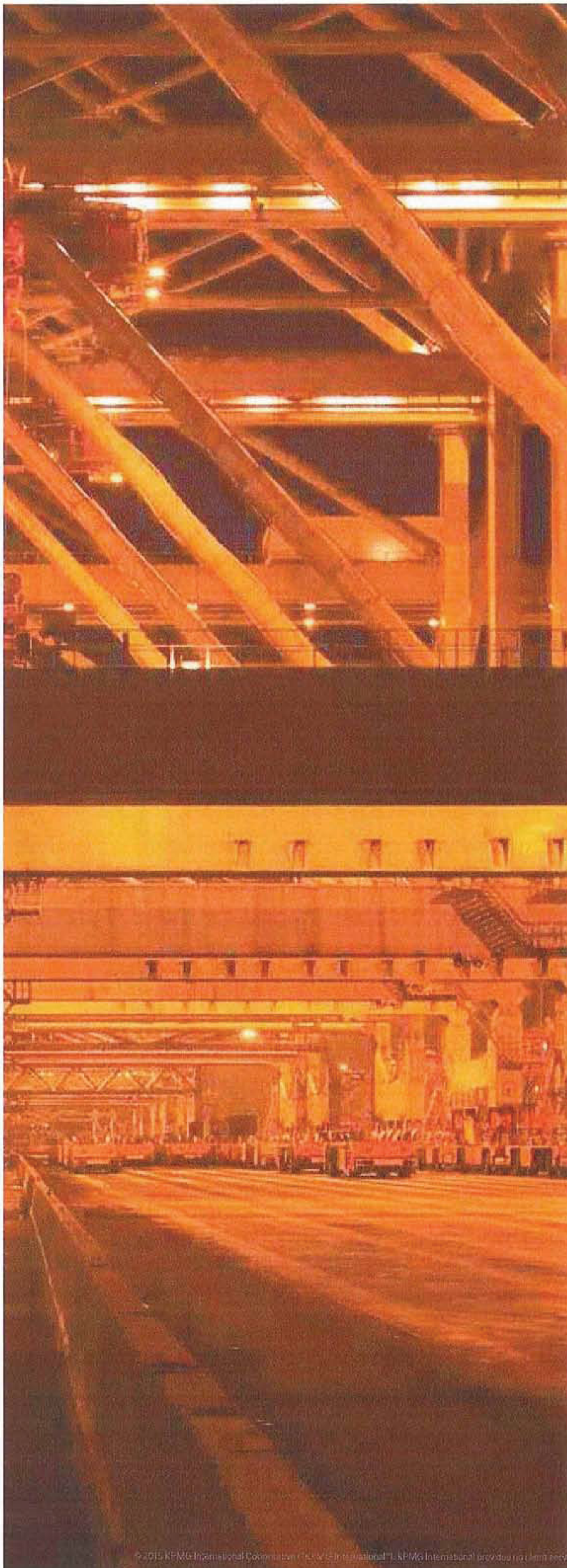

Introduction

As construction projects continue to evolve, grow larger and more complex, have organizations gained more confidence in their ability to hit schedule, budget and quality targets?

Project owners are continually striving for a balance between power, responsibility and control. They have the power that comes from control over the budget, yet are ultimately responsible to their corporate Boards and Chief Executive Officers. They bear the responsibility for huge projects worth billions of dollars, along with the associated commercial and reputational costs of failure. Yet, project owners have to cede much of the project execution risk and control to industry experienced engineers and contractors.

Managing these dynamics requires maturity. Maturity in planning and financial forecasting; maturity in hiring and developing the right talent; maturity in ongoing risk and project management; maturity in contingency management to cope with the inevitable setbacks that accompany major construction projects; and maturity to build positive and effective working relationships with contractors that bring out the best in all parties.

In the ninth edition of KPMG's Global Construction Survey we focus on the challenges facing owners as they seek to climb the maturity curve and feature the views of over 100 senior executives from both private and public organizations whose annual capital expenditure ranges from a few million US dollars (US$) to well over 5 billion US dollars.

The results, augmented with commentary from KPMG's Major Projects Advisory specialists and external industry experts, should enable project owners globally to chart their own levels of project delivery maturity.

I would like to thank all survey participants who gave their valuable time to participate in the report.

Geno Armstrong
International Sector Leader
Engineering & Construction
KPMG in the US

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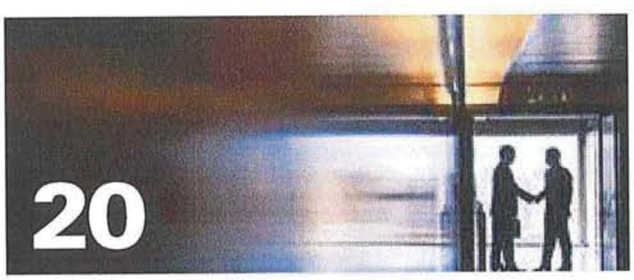
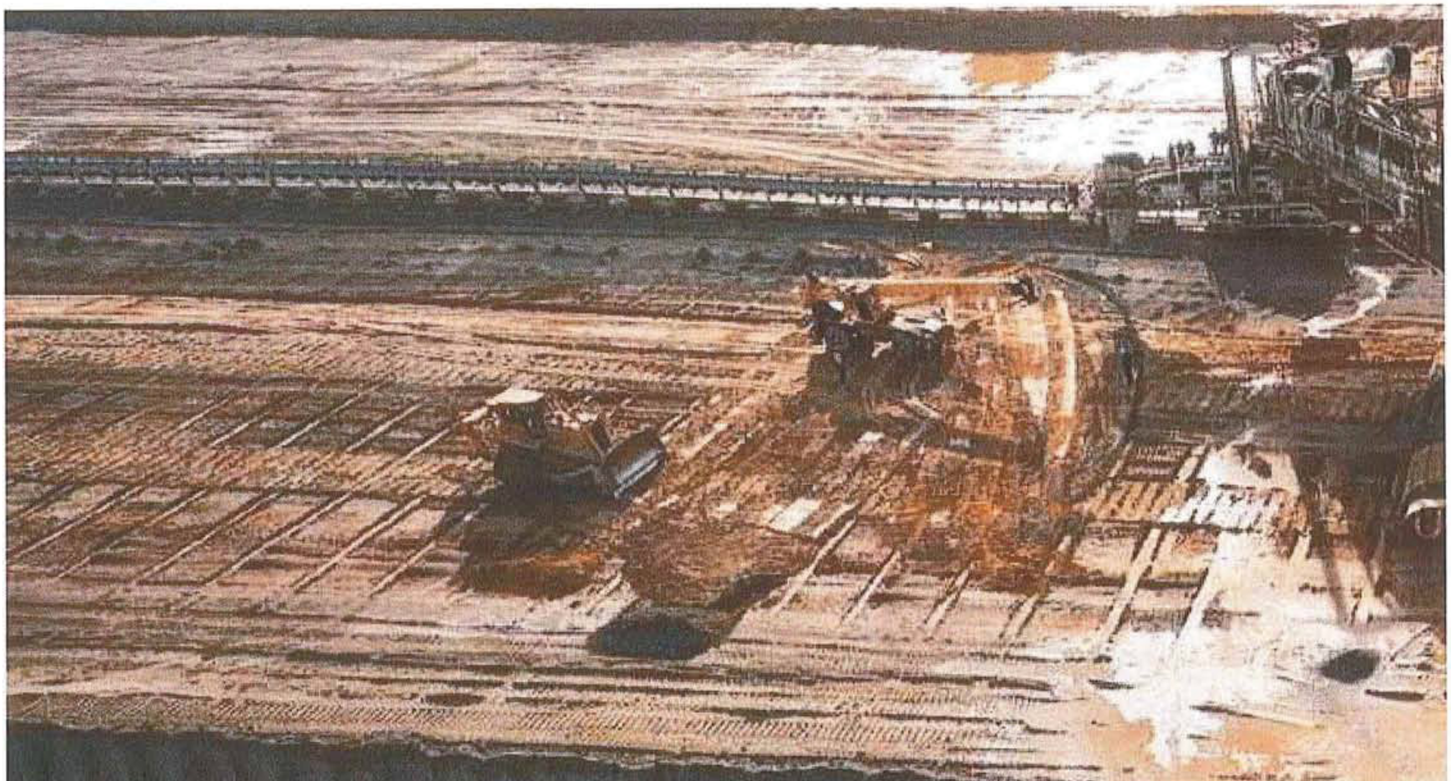



ONE WAY



» Executive summary

How are project owners performing on the maturity curve?

In late 2014, KPMG interviewed executives from over 100 private and public organizations around the world that carry out significant capital construction activity. The respondents' annual revenue varied in size from US$250 million to more than US$5 billion, covering a wide range of sectors including energy and natural resources, technology and healthcare. More than a quarter of the respondents worked for government agencies.

Maturity in preparation

Planning and prioritizing appear to be rigorous

- 30% of respondents say their organization uses the design-bid-build approach and 32% favor engineer-procure-construct (EPC)
- 74% complete a formal project delivery and contract strategy analysis, prior to approval
- 84% utilize financial and risk analysis to screen projects
- 80% say the majority of capital projects are planned

Talent shortages remain a challenge

- 44% struggle to attract qualified craft labor and 45% lack planners and project managers
- Organizations with fewer full-time project staff spend more on capital expenditures per employee
- 69% hire external resources equivalent to more than 5% of the total workforce on a per project basis

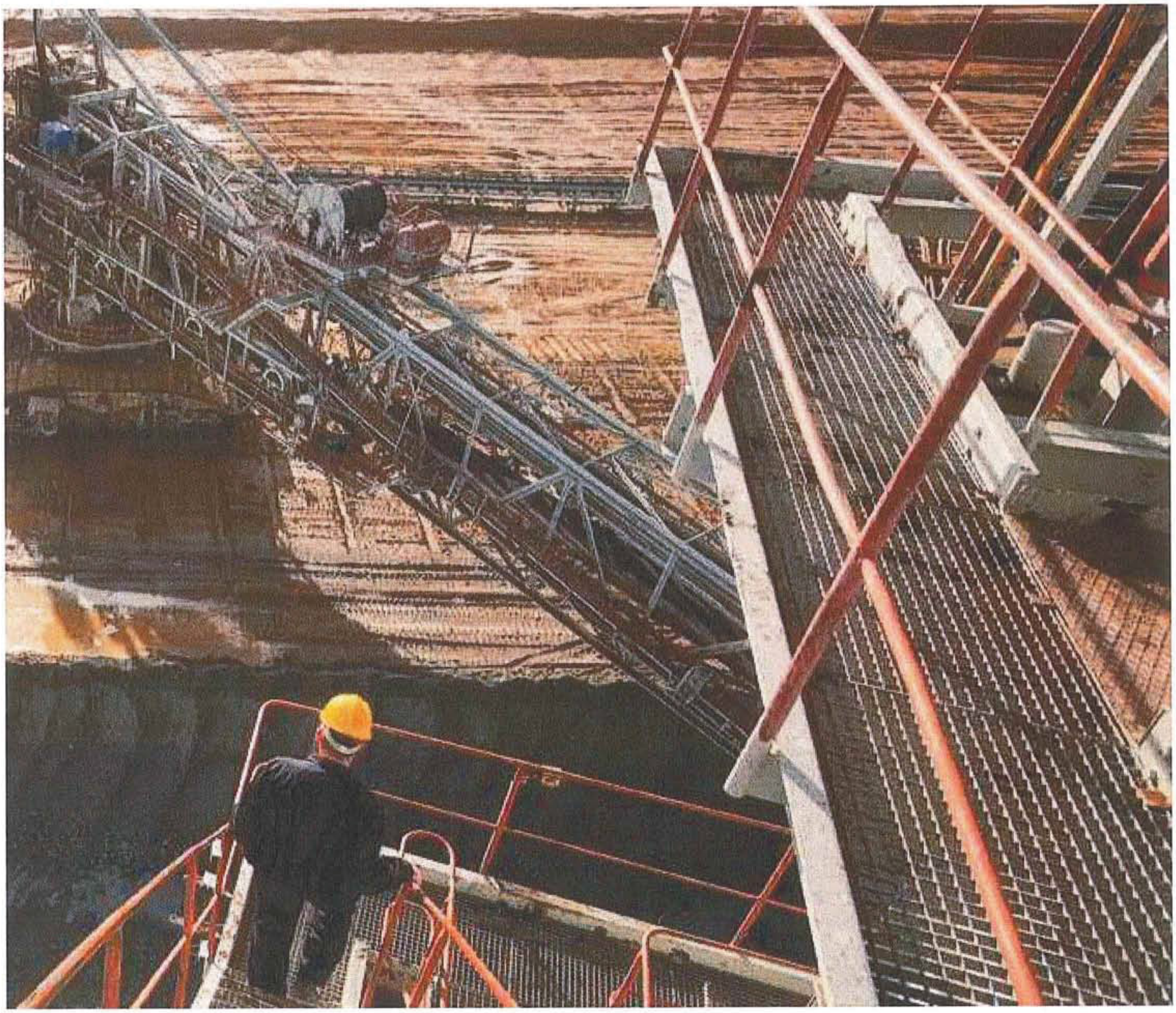
Maturity in risk, controls and governance

Owners express confidence in their project controls

- 64% say their management controls are either 'optimized' or 'monitored'
- 55% are 'satisfied' or 'mostly satisfied' with their investment in project management
- 74% feel investment in controls and governance has reduced costs
- 73% are comfortable with the accuracy and timeliness of project level reports

Project management information systems (PMIS) not yet ubiquitous

- 50% use PMIS; of those that don't, 41% plan to introduce this within 2 years
- 32% of those that use PMIS have yet to integrate it with their accounting and procurement software



Maturity in performance

Owners continue to experience project failures

- 53% suffered one or more underperforming projects in the previous year. For energy and natural resources and public sector respondents the figures were 71% and 90% respectively.
- Only 31% of all respondents' projects came within 10% of budget in the past 3 years
- Just 25% of projects came within 10% of their original deadlines in the past 3 years

A mixed approach to contingency planning

- 30% perform quantitative risk analysis to calculate contingencies
- 49% use both a project-level contingency *and* a management reserve
- 30% draw down from a single pool of contingency based upon project risks

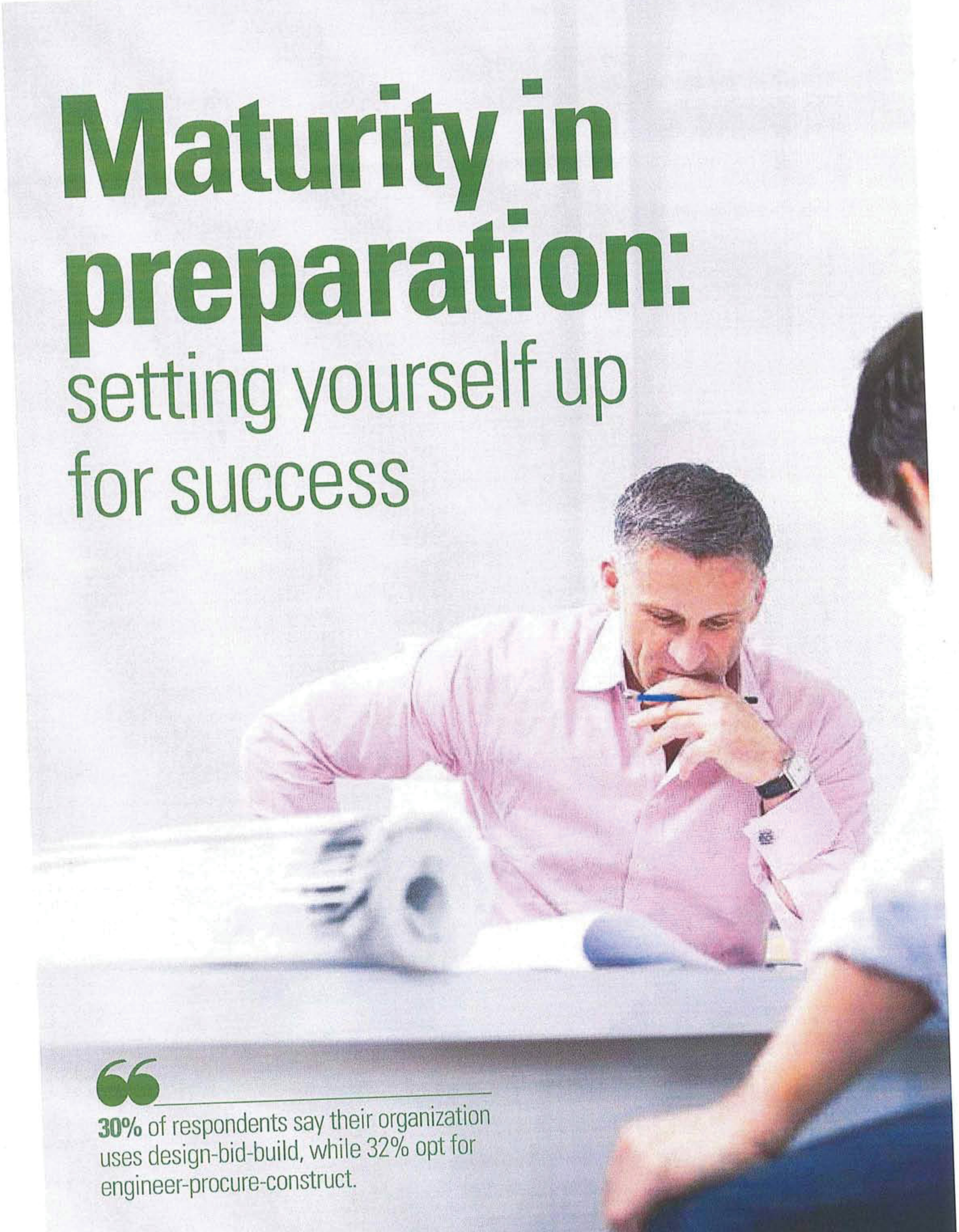
Maturity in relationships

The push towards contractor collaboration may need more impetus

- 82% expect greater owner/contractor collaboration over the next 5 years
- Just 32% have a high level of trust in their contractors
- 69% say poor contractor performance is the single biggest reason for project underperformance

Contracts continue to emphasize the divide between contractors and owners

- 58% are lump sum (fixed price) contracts
- 72% hold full competitive tenders when awarding contracts
- 48% expect to have more negotiating strength vis-à-vis contractors



Maturity in preparation:

setting yourself up for success

30% of respondents say their organization uses design-bid-build, while 32% opt for engineer-procure-construct.

Most of the owners in the survey use formal screening, prioritizing and approval processes for projects, including financial and risk analysis

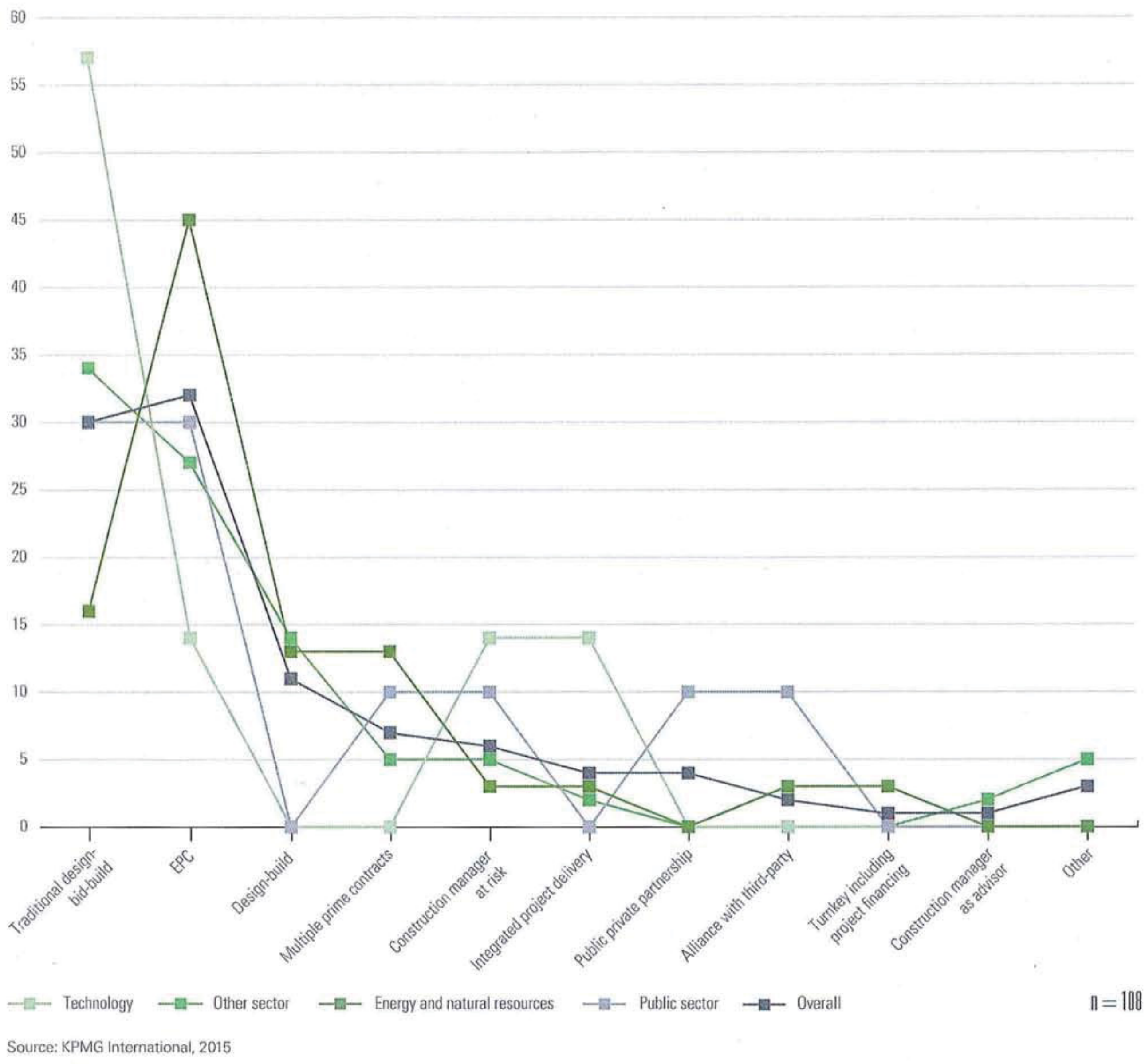
Despite some concerns about a lack of flexibility, the traditional design-bid-build approach remains one of the two most popular project delivery strategies, enabling the owner to work with various suppliers for different aspects of the project. Sharing the top spot is engineer, procure, construct (EPC), which leaves the contractor in control of design, procurement and construction, giving the owner a single point of contact from start to finish. Both these delivery strategies shift the project risk firmly into the hands of the contractor and suggest either a high level of trust in contractors – or a desire by construction owners to defer the risk and responsibility of project execution to contractors.

Almost half of the respondents are concerned about the lack of key skills in-house and augment their teams with external specialists

Respondents from companies in the energy and natural resources sector are the most likely to favor EPC, while technology businesses, and organizations with a turnover of US$1 billion to US$5 billion, are more likely to favor design-build.

There is significant evidence of a mature and structured approach to planning, prioritizing and approving projects. Three-quarters of the executives taking part in the survey say that their organization completes a formal project delivery and contract strategy analysis prior to senior management's authorization of projects. Construction activity is also carefully vetted in advance, with a large majority (84 percent) reporting the use of financial and risk analysis to screen projects.

Most popular project delivery strategy



Source: KPMG International, 2015

Most owners appear to have a formal ranking process for prioritizing potential projects using pre-established criteria such as operational safety, environmental, legal and regulatory factors, and overall return on investment. A substantial proportion also augments this with more ad hoc analyses.

Much as one would expect, more than 80 percent of owners state that the majority of their capital projects are planned (i.e. are within the annual capital plan), and a similar percentage claims that planned and unplanned initiatives must go through the same rigorous approval process.

Although over half of those taking part in the 2015 survey plan projects at least 5 years ahead, executives from the larger companies are more likely to have a shorter timeframe. Fifty percent of those from organizations with annual turnover greater than US$5 billion say that they only plan ahead for 3 or fewer years. This could reflect the need to respond quickly to changes in demand, backed by a more sophisticated forecasting capability and an internal project development and management team that can mobilize at short notice.

Number of years into the future organizations plan capital construction projects

Source: KPMG International, 2015

84% of owners surveyed utilize financial and risk analysis to screen projects.

Prioritizing projects: Optimizing your portfolio

Jeff Shaw
Director, KPMG in South Africa, discusses the processes and considerations needed to help optimize project portfolios.

Whether project owners are operating in buoyant capital project markets or in those still emerging from the economic slowdown there is intense competition internally for funding and people, and externally for scarce contractor resources. Consequently, organizations need to manage their capital efficiently and effectively across a wide range of projects, to ensure they are aligned with strategic goals.

Core capital allocation components include capital budgeting and planning policies and procedures, a cross-functional capital review committee, and a robust system for tracking and reporting across the portfolio. All potential projects should be systematically identified, classified, screened, prioritized, evaluated and selected. This process must be supported by an appropriate budget allocation and monitoring process. Throughout the capital allocation process, alignment between strategic objectives and the capital project portfolio must be tested.

Of course, this is not the only way to optimize the portfolio; however, this and other approaches should always have established guidelines, to keep projects in line with growth and profitability targets.

With a seemingly endless pool of possible projects, and the need to balance competing interests within ever changing capital and capacity constraints, organizations can struggle to choose the most appropriate mix. Some lack basic guidelines, and may cast the net too wide, which leads to a time-consuming review process that overloads decision-makers with excess information, and causes unwanted internal conflict. Others employ unnecessarily narrow parameters that fail to allow for innovative suggestions that could bring great value.

Once a project is selected, it is easy to neglect the process of evaluating performance against the original business case, to clarify any learnings and document financial data. Given the huge amounts spent on construction projects, the relative success or failure of capital allocation and portfolio optimization could ultimately determine the organization's entire survival.

Keeping the talent conveyor belt running

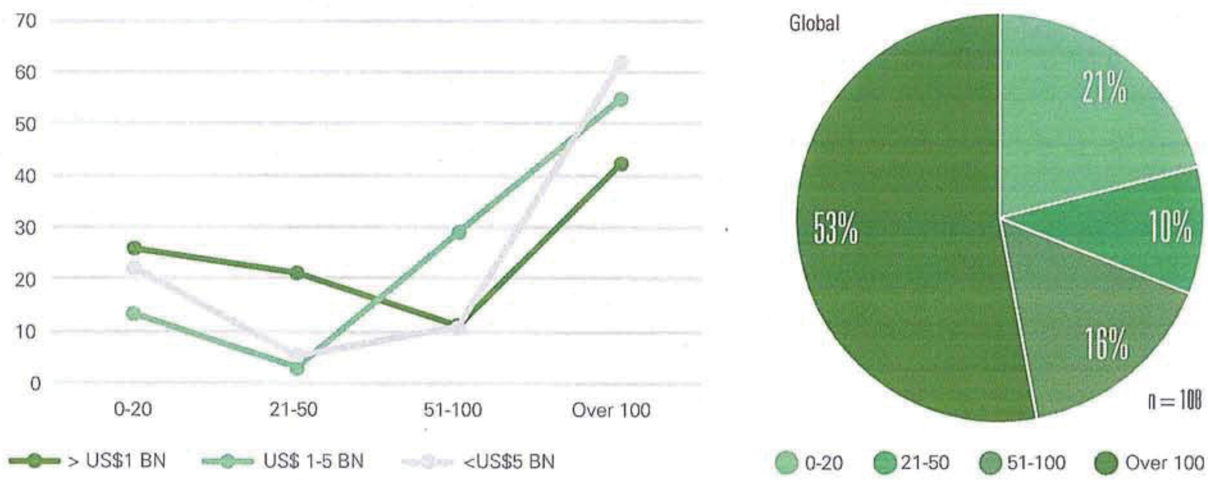
In order to successfully manage the enormous responsibility of a multi-billion dollar project, owners are heavily dependent upon capable project management teams that understand engineering and construction, project management principles and practices and, not least, the increasingly sophisticated technology that controls every step.

The talent gap is a much-discussed phenomenon in the industry, and owners face the same challenges that contractors have been grappling with for years – to attract, train and retain the best people in the face of severe competition from other sectors. Forty-four percent of respondents say that they struggle to attract qualified craft labor to projects, and a similar percentage claims that a lack of available planners and project management professionals is hampering their project progress.

One respondent feels that one of the organization's most pressing needs is: "making sure we have well trained project managers with good tools to complete projects on time and within budget."

Not surprisingly, there is a strong correlation between organizational size and number of full-time employees specifically assigned to projects. Almost half of respondents from smaller organizations (less than US$1 billion turnover) have 50 or fewer staff, while for the largest entities (turnover greater than US$5 billion), three-quarters have teams of over 50 and 62 percent have more than 100 employees.

Number of full-time employees (FTE) planning and managing capital construction projects



Source: KPMG International, 2015

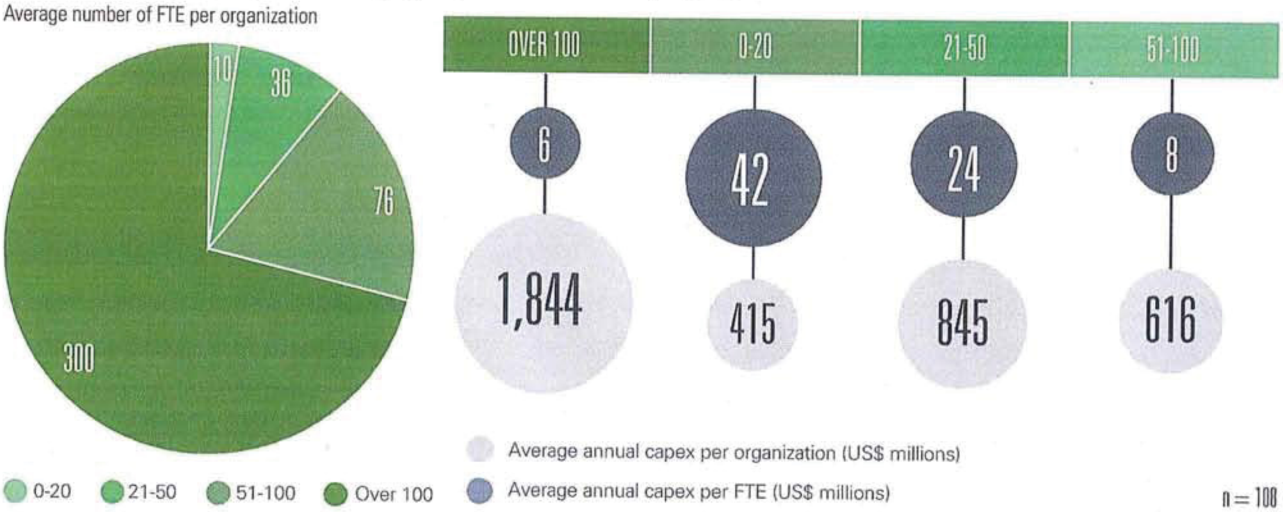
Those organizations with fewer full-time project staff tend to have a higher annual average capital expenditure per employee. Fears that this could stretch their resources are not borne out by the findings, which show that the smaller institutions in the survey also report a lower rate of underperforming projects. This suggests that it is not the quantity of employees that makes the difference, but the quality of employees.

The larger the organization, the more likely it is to have a significant pool of tried and tested project workers. Twenty-nine percent of respondents from larger entities say that they select their teams based upon past performance, compared to just 11 percent for the smaller organizations. Nevertheless, most project workers are chosen on a case-by-case basis.

> **44%** of respondents struggle to attract qualified craft labor and 45% cite a lack of planners and project managers.

Number of FTE planning and managing capital construction projects

Average number of FTE per organization



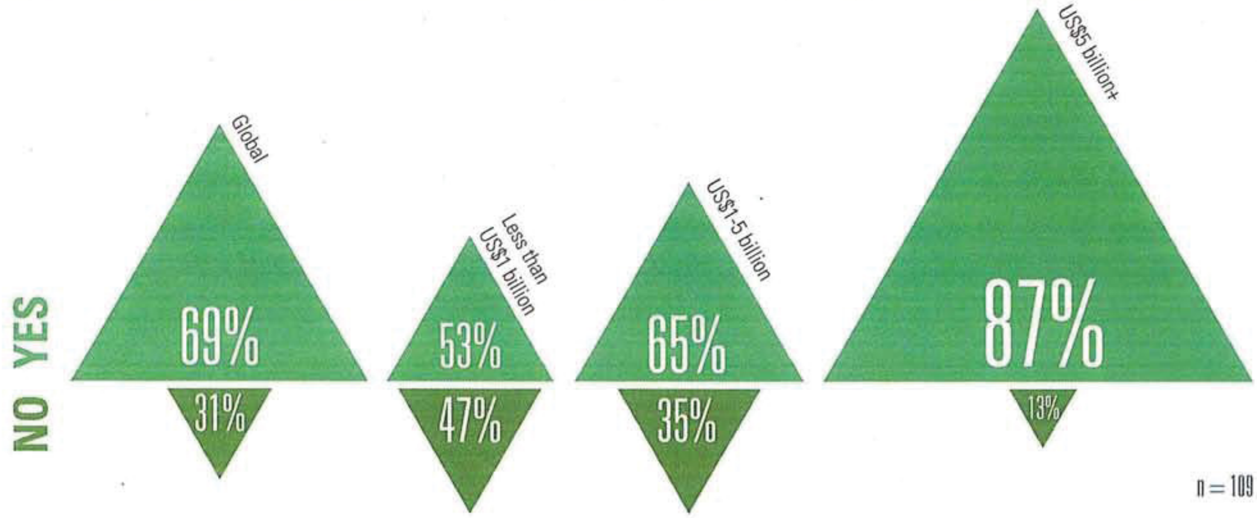
Source: KPMG International, 2015

A need for outside assistance

Despite investment in recruitment and training, owners routinely bolster their project teams with additional, temporary personnel, particularly in the aforementioned areas of craft labor and planners and project management specialists. Over two-thirds of the executives in the survey note the need to hire a significant number (more than 5 percent of the total workforce) of external project or program management experts to supplement existing staff. And, the larger the organization, the greater the need: 87 percent of the larger institutions report the necessity to bring in outside people.

The energy and natural resources sector has been hit hard by the recent plummeting price of oil, and most players, if not all, will have to reduce staff numbers, which can stretch resources when carrying out major construction projects.

Organizations hiring more than 5% of external project or program management personnel to supplement FTE



Source: KPMG International, 2015

87% of the larger organizations in the survey need to augment project teams with external resources.

Thinking differently: a strategic approach to talent management?

Angela Gildea
Principal, KPMG in the US, argues that project owners in traditional sectors should look to new industries for inspiration.

The art of managing mega projects is declining, while the projects themselves are becoming ever more complex. With many organizations outsourcing increasing numbers of tasks to engineering and construction firms, the required skills of internal staff change from 'executing' projects to managing schedules and contractors. And all of this is happening at a time when many traditional owners are seeing graduates enticed by different, often better rewarded positions in new industries. Companies can reap great benefits by taking a fresh approach to talent management.

Be more strategic

Research has found a distinct correlation between strong talent practices and greater shareholder return. For high performing companies, talent management is more than just a Human Resource issue – it's a strategic imperative and should therefore be closely aligned with wider business objectives and accountability shared across all levels of leadership. This means integrating talent considerations into the following areas:

- **business strategy:** to determine the people and processes to help achieve your goals
- **risk management:** ensuring availability of key resources and planning successors
- **investment and measurement:** measuring the return on investment in talent
- **governance and infrastructure:** ensuring clear ownership of talent management, with appropriate data and systems support.

Analytics: using data to drive talent decisions

Although data analytics is a mainstay in business operations, organizations have been slower to embrace this approach for managing talent, where uses include:

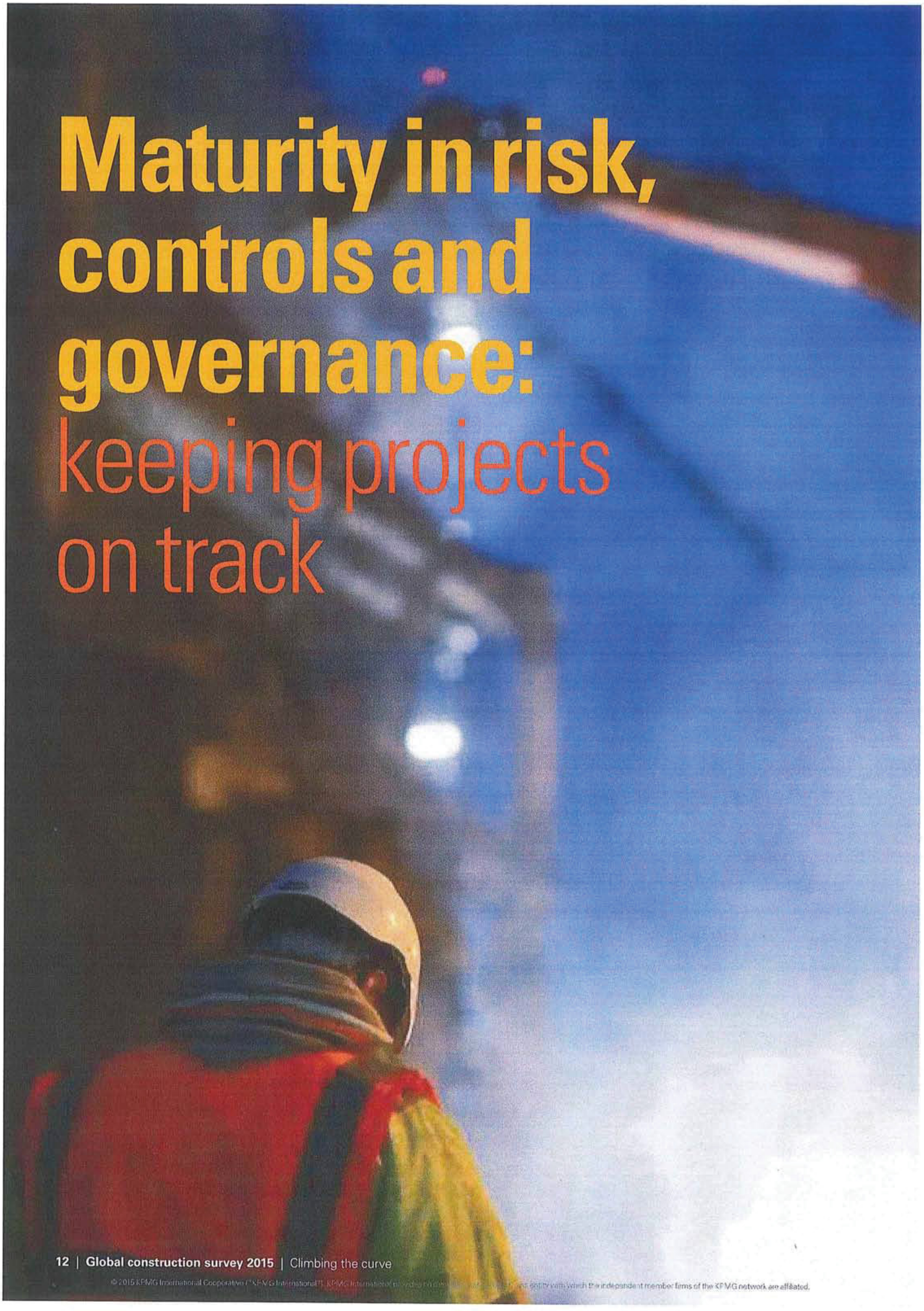
- **predictive modeling:** to more accurately forecast future people needs
- **retention algorithms:** to predict which employees are most likely to leave or retire
- **valuing top performers:** calculating the (potentially significant) difference between average and exceptional employees, to justify recruitment strategies and acknowledge individual contributions.

Embrace diversity…of cognitive thought

Most organizations now routinely consider diversity in their hiring practices, but this typically covers gender, race and culture. More enlightened employers are also seeking diversity of a different kind: of cognitive thought, using the following practices:

- **learning and training:** by incorporating courses into formal learning curriculum to build and encourage cognitive diversity
- **hiring the unconventional candidate:** looking beyond the traditional resumé for different skill sets. For instance, data scientists and mathematicians are being hired for operational roles, to introduce innovation and "out of the box" thinking.
- **looking beyond established employees:** to gain additional, external insight from suppliers, independent contractors, customers and recent experienced hires, utilizing emerging technologies such as crowdsourcing and gamification.

Maturity in risk, controls and governance: keeping projects on track



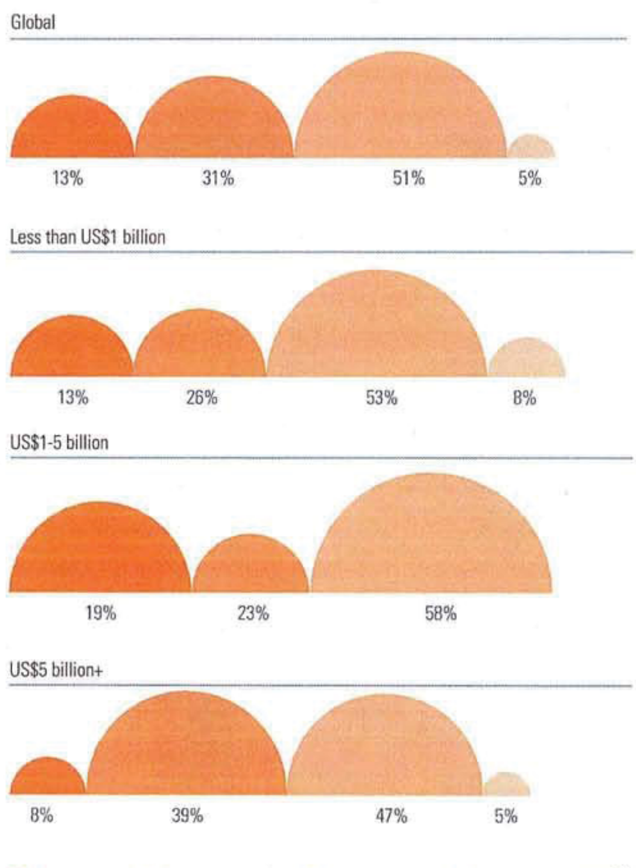
64% of respondents believe that their management controls are either 'optimized' or 'monitored.

- **Owners appear confident that their investments in project controls have paid off**
- **Half of the respondents say their organization has yet to introduce an integrated project management information system (PMIS)**

A strong sense of optimism pervades the responses to this year's survey. Sixty-four percent believe that their management controls are either 'optimized' or 'monitored,' meaning that they are documented and integrated, with either real-time or periodic testing and reporting, and frequent or occasional training.

However, almost a third of respondents feel their controls are merely 'standardized,' with no testing or reporting to management and only limited training of staff. These organizations may need to consider how they can upgrade this approach to introduce a best practice. The technology companies taking part in the survey are the least likely to have optimized or monitored controls.

Level of sophistication of project management controls



Source: KPMG International, 2015

Over the past decade, owners have paid considerable attention to introducing cutting-edge software to improve their project controls. This appears to have brought positive results. When asked about the return on investment in project management tools and training, 55 percent indicate that they are either 'satisfied' or 'mostly satisfied,' while just a handful (13 percent) say they are not satisfied. It is a similar story when it comes to assessing the benefits of investment in risk management tools and project cost reduction.

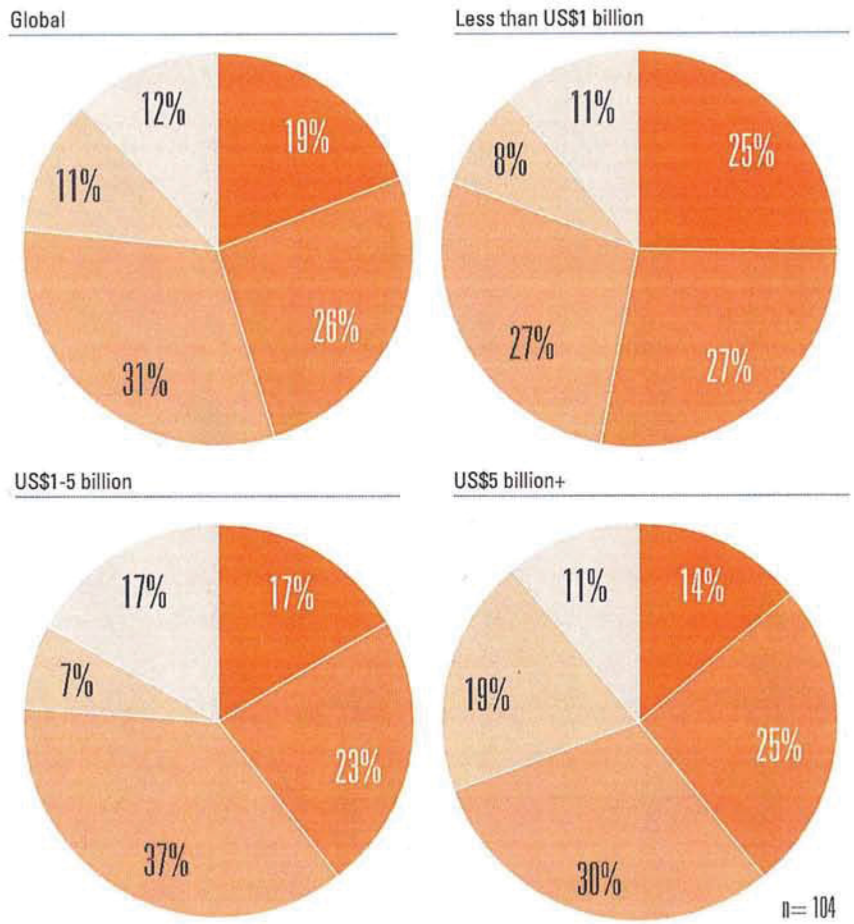
The respondents also believe that the money spent on project governance and controls has paid off. Over three-quarters say that they have 'definitely', 'mostly' or 'somewhat' reduced costs. However, a significant minority of executives (30 percent) from larger organizations in the survey believe that these investments have either not resulted in lower costs, or are unsure of their benefits. It is possible that the scale and complexity of the organization, along with disparate systems, have restricted the impact of new software, which may not be fully integrated.

The optimism continues when the subject of reporting is raised. A large majority of 73 percent are confident about the accuracy and timeliness of the project level reports they get from their project managers and contractors. Once again, however, respondents from the bigger companies or institutions are slightly more cautious, with a third not convinced of the quality of reports, which could reflect the dearth of skilled personnel among their substantial project management workforces.

Most respondents (86 percent) say that their capital construction projects are tracked and reported on a portfolio basis.

Have investments in project governance and controls reduced project costs?

Yes | Mostly yes | Somewhat | Unsure | No



Source: KPMG International, 2015

> Almost half of the larger organizations that use PMIS have yet to integrate it with their accounting and procurement software.

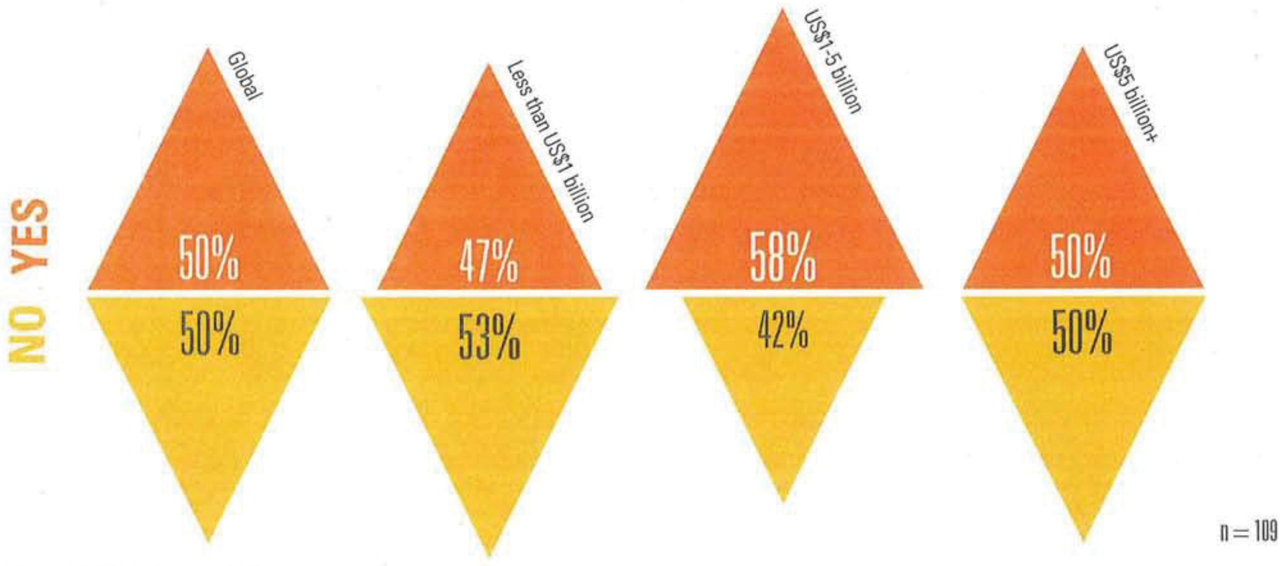
Project management information system use still not widespread

A PMIS is designed to improve project planning, scheduling, monitoring and controlling, in order to raise the quality of decision-making in each phase of the project life cycle. It enables engineers and project managers to communicate project status swiftly and accurately with functional departments, while also keeping senior management up to speed on all the projects in the organization's portfolio.

The respondents to this year's survey are divided exactly 50:50 in their use of such systems, suggesting there is considerable room for improvement – although 41 percent of those without a PMIS say that they plan to acquire one within 2 years.

Of those who have embraced PMIS, a third have yet to integrate it with their accounting and procurement software, and are consequently failing to realize the full benefits of this technology. This figure leaps to 47 percent among the bigger organizations where, arguably, the potential upside is even greater given the scale of their engineering and construction projects.

Is your organization using PMIS to plan and control capital construction projects?



Source: KPMG International, 2015

The perils of confidence: realities of benchmarking

Clay Gilge
Partner Advisory, KPMG in the US, explains how benchmarking the effectiveness of project management processes can provide a much-needed reality check.

Is the confidence in project controls expressed by the survey participants warranted or misplaced? Our global clients ask the same question continuously, as they strive to avoid the kind of setbacks that can cost millions, damage reputations and hold back business.

In response, we have come up with an ongoing benchmarking analysis that evaluates the maturity of clients' processes and controls over time against peers, as well as internally by region and business unit. Ranking these controls at four levels, from the lowest tier 'informal,' through 'standardized,' 'monitored' and, finally, 'optimized,' we find that organizations are consistently over-optimistic in their self-ratings, which typically are a whole tier above our rigorous benchmarked findings.

In this year's survey, for example, 51 percent of owners indicated they are 'monitored,' when our data indicates that only 28 percent have reached this level, with a majority still merely 'standardized.' An inappropriate rating could generate a degree of over-confidence that could potentially lead to problems.

Our tried-and-tested approach requires the verification of actual project management process and control maturity, through document review and project testing. This gives the benchmarking far more depth and enables clients – many of whom are Fortune 500 companies or public infrastructure organizations – to develop a road map toward continuous improvement. As you would expect, the cloud-based methodology is grounded in global project management standards and frameworks such as PMBOK and PRINCE2. We also quickly realized that any assessment must include additional criteria such as sustainability, fraud risk management and 'soft' controls, all of which have been integrated into the benchmarking to produce a comprehensive picture.

Tier 1 – Informal

- minimal processes or controls are designed or appear effective
- no apparent project management process/control for monitoring or improvement activity.

Tier 2 – Standardized

- project management process/control design and effectiveness appear to be moderate
- minimal project management process/control monitoring or improvement activity.

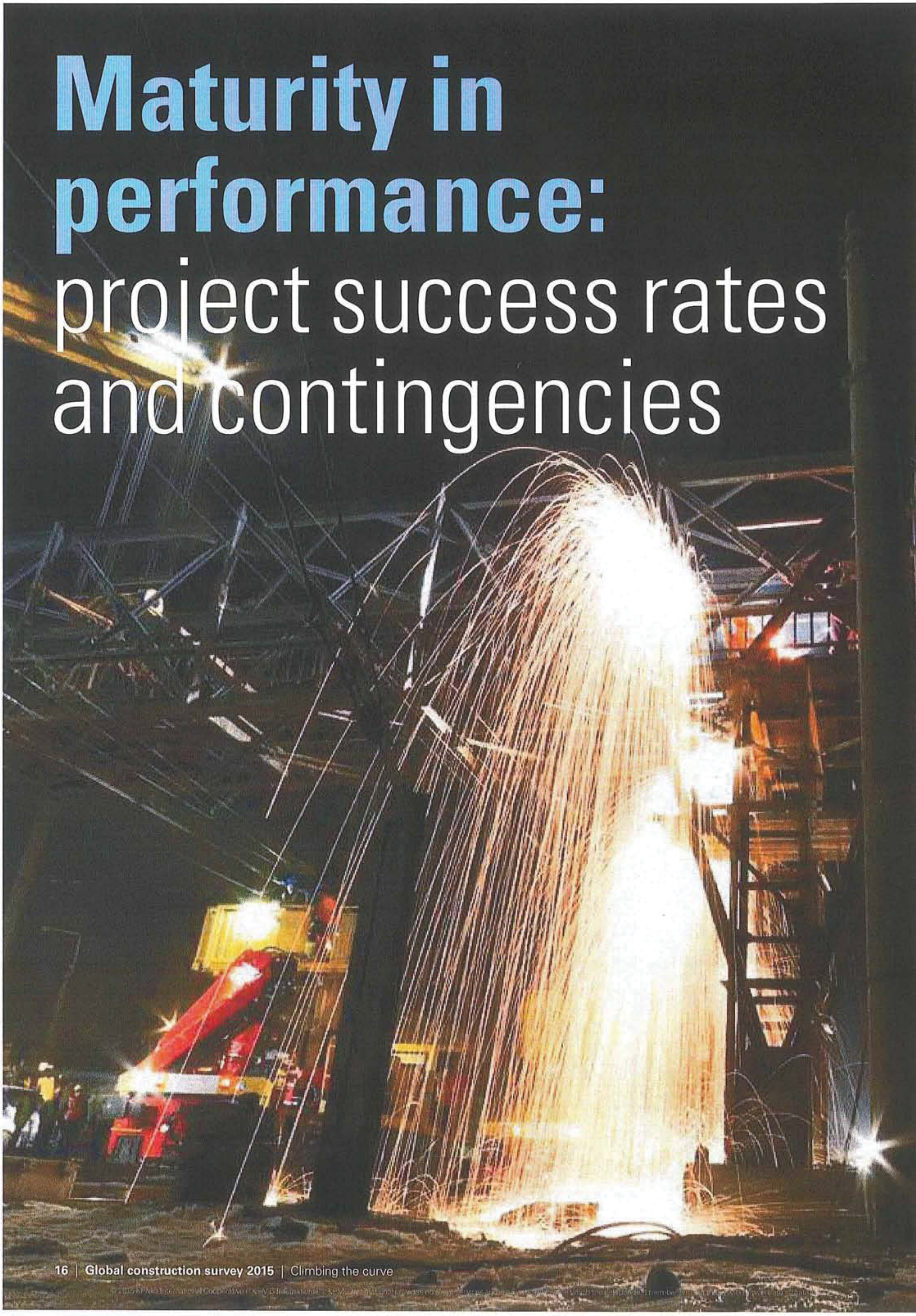
Tier 3 – Monitored

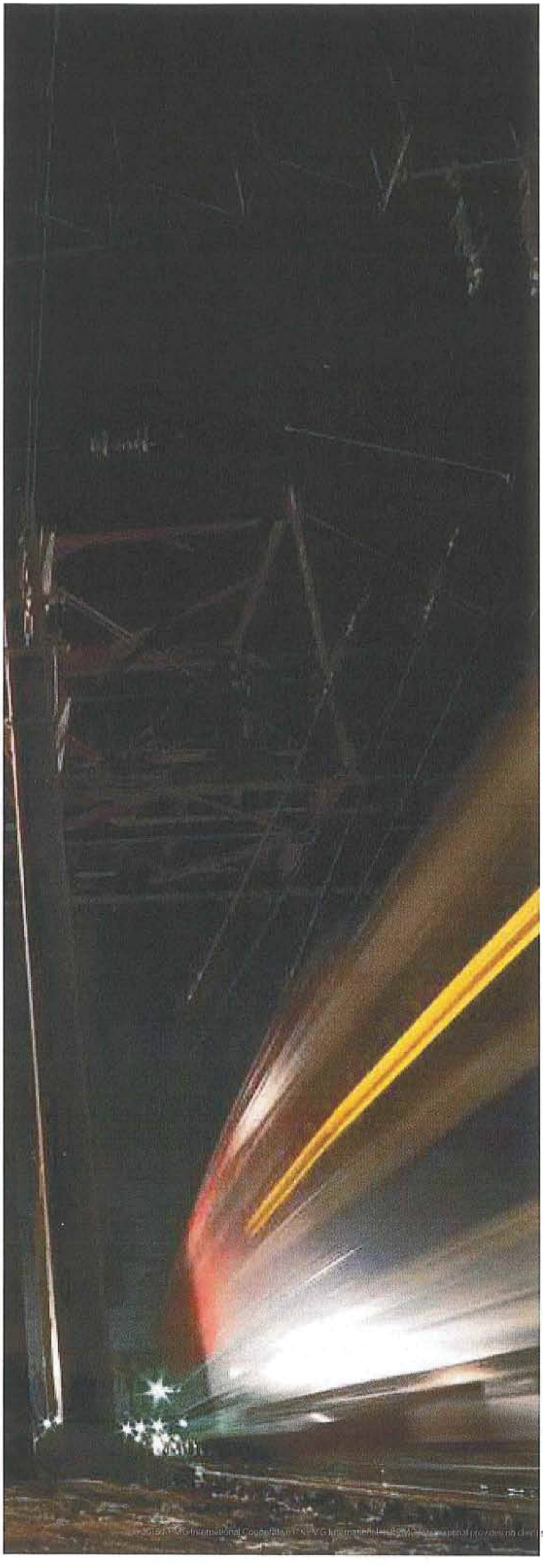
- project management process/control design and effectiveness appear adequate
- periodic project management process/control monitoring and improvement.

Tier 4 – Optimized

- comprehensive project management process/control design that appears to be effective
- continual project management process/control monitoring and improvement.

Maturity in performance: project success rates and contingencies



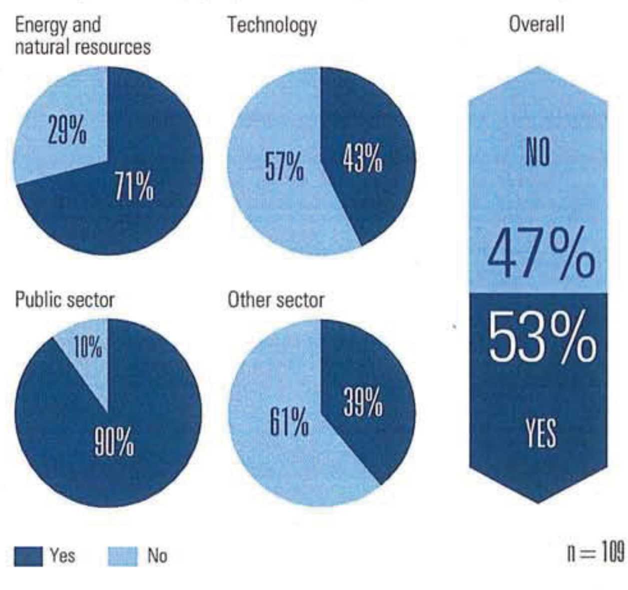


> Realism eats optimism for breakfast – owners should demand practical targets from contractors based upon realistic expectations of what can go wrong.

- **Owners are still failing to bring projects in on time and on budget – especially those in the energy and natural resources and public sectors**
- **Half of respondents do not use a management reserve, which could lead to an over-optimistic view**

The significant investment in project controls – and the high levels of confidence that many owners have in these controls – have not halted the run of underperforming projects. Over half of all the respondents state that they suffered one or more underperforming projects in the previous financial year. For larger organizations, this rose to 61 percent, while executives from the energy and natural resources and public sectors experienced even higher levels of project failure, at 71 percent and 90 percent respectively.

Underperforming projects during the last financial year



Source: KPMG International, 2015

Looking back over the past 3 years, fewer than one-third of all respondents' projects managed to come within 10 percent of the planned budget, with the energy and natural resources, and especially the public sector, performing considerably worse than other industries.

Percentage of projects meeting planned budgets

Source: KPMG International, 2015

And, in the same time period, just a quarter of construction projects came within 10 percent of their original deadlines; only one in ten public sector organizations managed to hit this target.

One interesting observation is that businesses with turnover between US$1 billion and US$5 billion report the best results. Forty-five percent say they met, or were very close to meeting, their budget, and 34 percent managed to achieve similar high standards for delivery times.

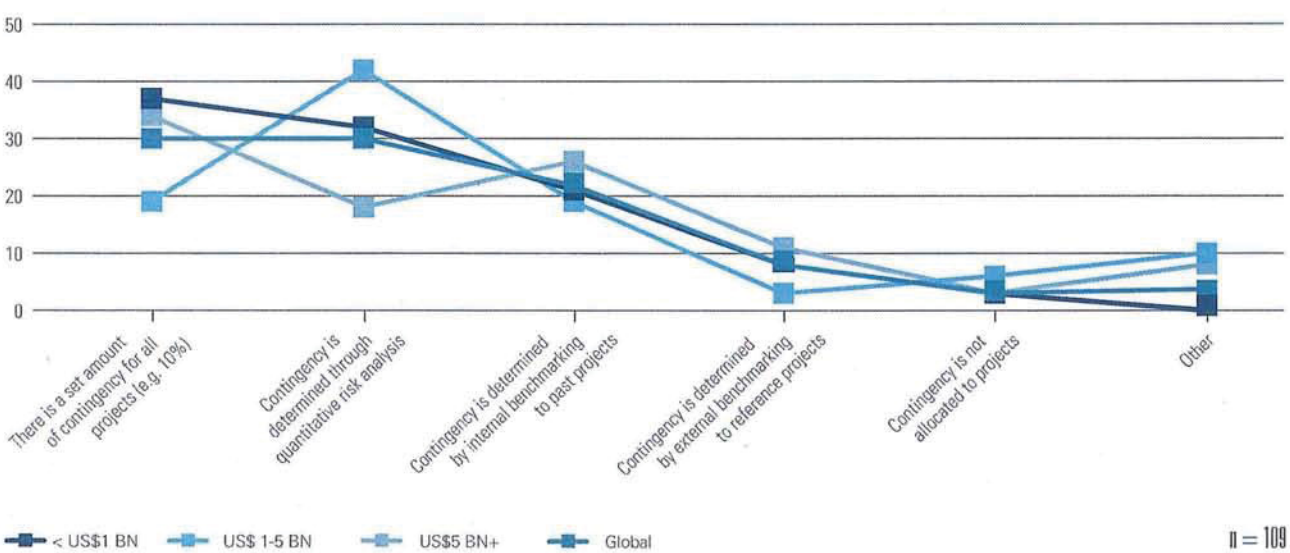
These findings suggest that, while controls may bring many benefits, they have yet to be fully and effectively embedded. The results also raise questions on the skills of those working with the various controls, either within PMIS or otherwise.

Planning for delays and cost overruns

According to one of the survey participants, one of the biggest concerns is "Accurate estimating of anticipated costs prior to committing to the project. Projects are moving so fast they have limited time to develop the scope and accurately estimate costs. This results in issues where the standard contingency used (10 percent) is not enough to cover the project risks."

Contingency planning typically involves downside risk estimates for budget and delivery times throughout the project life cycle. According to the senior executives participating in this year's survey, a range of methods is used to calculate contingency levels. The two most popular approaches are: 1) a set percentage, and 2) quantitative risk analysis, with 30 percent respectively opting for these choices. The relative sophistication of the latter suggests that owners are trying to become more accurate in their forecasting, with respondents from companies of US$1 billion to US$5 billion turnover more likely to adopt quantitative risk analysis.

Main method for determining project contingency



Source: KPMG International, 2015

The survey findings indicate that bigger organizations (which tend to have larger and more complex projects) are more likely to take a conservative view of contingency levels. Over half of the respondents from this segment report that the typical range of contingency is greater than 10 percent of the total estimated cost. Arguably, the size and scale of their project portfolios have led to a cautious attitude, tempered by past project cost overruns.

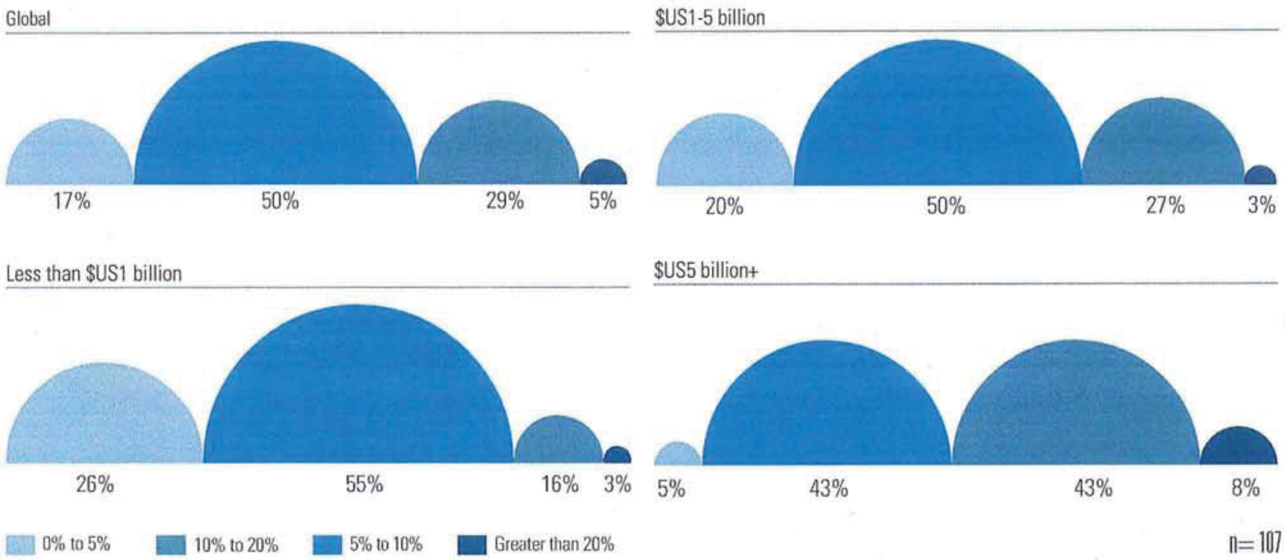
Only half of the respondents state that their organizations use both a project level contingency *and* a management reserve. Management reserves recognize the potential for risks that are outside of the project team's ability to control, which reflects a more realistic and pragmatic view.

In terms of managing contingencies, the single most common method (used by a third of respondents) is to allocate and, if necessary, reallocate contingency funds directly to control accounts based on ongoing project risk assessments. While the use of ongoing risk assessments is a leading practice, allocation of contingency directly to control accounts does not give the project manager good visibility into how the contingency is being used.

Thirty percent (and 34 percent of executives from larger organizations) say that they choose to draw down from a single pool of contingency based upon project risks, which shows a more mature and sophisticated approach.

A further 23 percent operate contingency as a single "balancing account" with transfers to and from other control accounts as needed. This only tracks contingency in and out of the project and is not a preferred means of managing contingency in the context of risk.

Range of project contingency (as a percentage of estimated costs)



Source: KPMG International, 2015

Less optimism, more logic: the art of scheduling

Gerald Long

Manager Advisory, KPMG in the US, explains some of the lessons he's learned from over 30 years in construction management.

Scheduling is one of the most difficult and least understood aspects of a project. As well as helping to plan ahead and model outcomes, it can track progress and provide realistic expectations.

With tens of thousands of activities to manage, too many project teams get bogged down in intense detail at earlier stages, rather than viewing activities at a summary level. And most scheduling is far too optimistic, based upon tight estimates with little leeway for delays. It's little surprise that, as this survey shows, only a small proportion of projects meet their delivery and cost goals.

We prefer to apply logic built upon knowledge and experience of what actually happens during the construction life cycle – and what can go wrong. Unfortunately, contractors are nervous about doing this, for fear of scaring the owner, so persist with unachievable targets. Scheduling is not a 'dark art,' but it is a complex one, and practitioners must be intimate with the many sequences within a project, and know what questions to ask subject matter experts. They also need to be able to link the cash flow with the work flow, to evaluate the financial impact of any delays.

The biggest project failures are caused by poor scope management and inadequate communication. A good scheduler stays on top of the workflow and keeps the client informed of realistic progress and projected outcomes.

Maturity in relationships: the new dynamics of collaboration

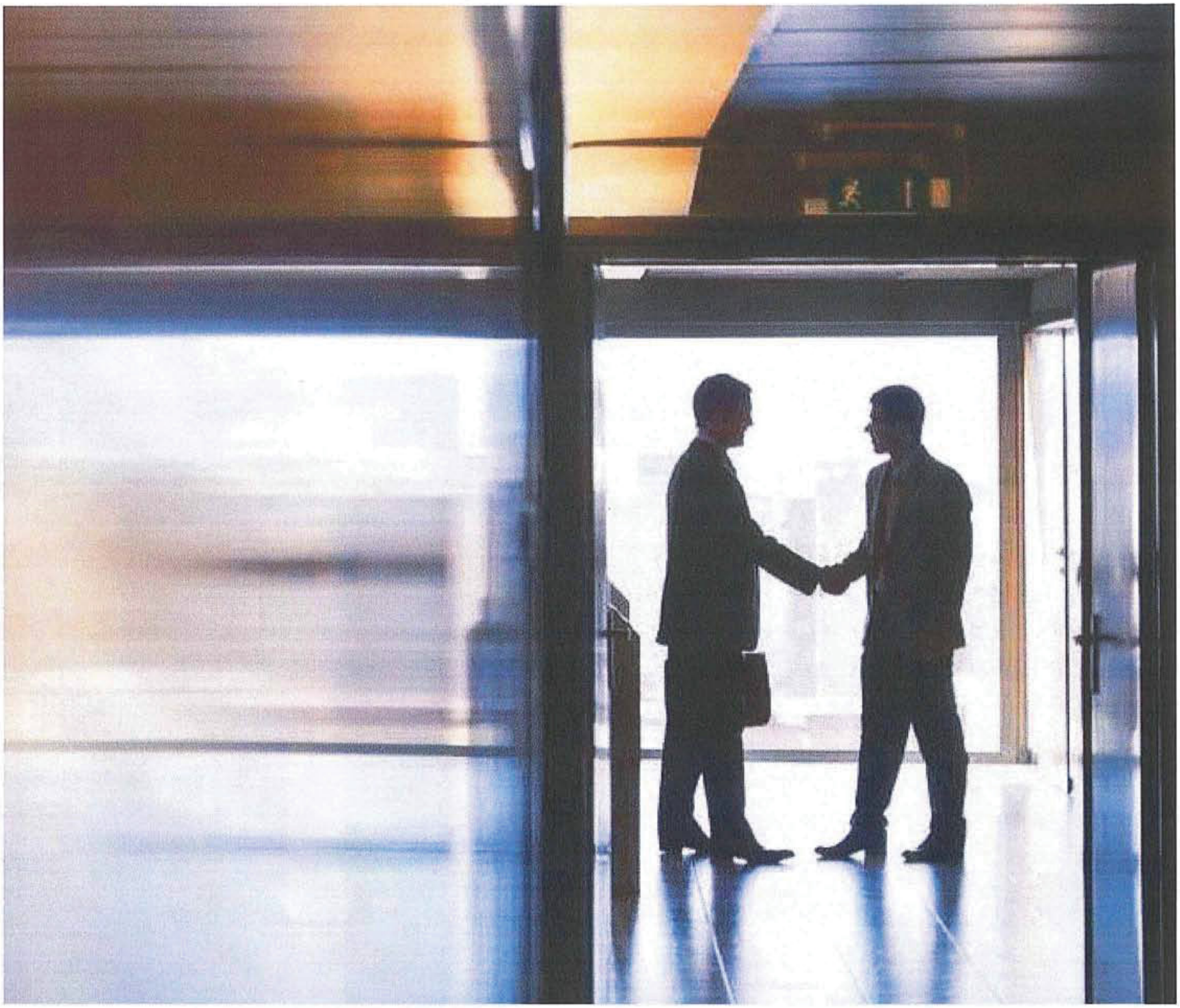
82% of respondents expect greater owner/contractor collaboration over the next 5 years.

- **Project owners seek closer ties with contractors, but have yet to build truly trusting partnerships**
- **Lump sum/fixed price contracts remain the norm**

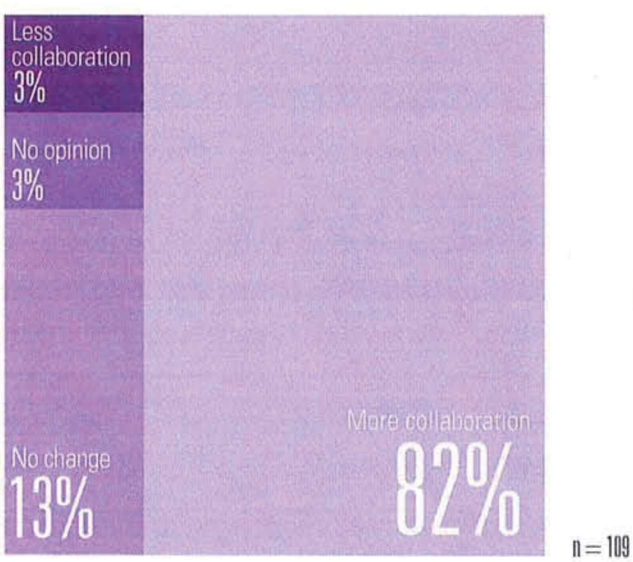
Successful projects are dependent upon strong teamwork, and owners are constantly reviewing the effectiveness of their relationships with contractors. An overwhelming majority of the respondents anticipate more collaboration over the next 5 years. One interpretation of these findings is a desire to integrate contractors into the boardroom to help streamline project delivery, drive down prices and pass on greater risk.

There is, however, another way of looking at the results. Owners may want to stay closer to contractors because they do not *fully* trust them. Only a third believe they have a 'high' level of trust in their contractors, with 60 percent describing the degree of trust as merely 'moderate.'

Indeed, poor contractor performance is cited as the single biggest reason for project underperformance, with over two-thirds (69 percent) of survey participants ticking this box.

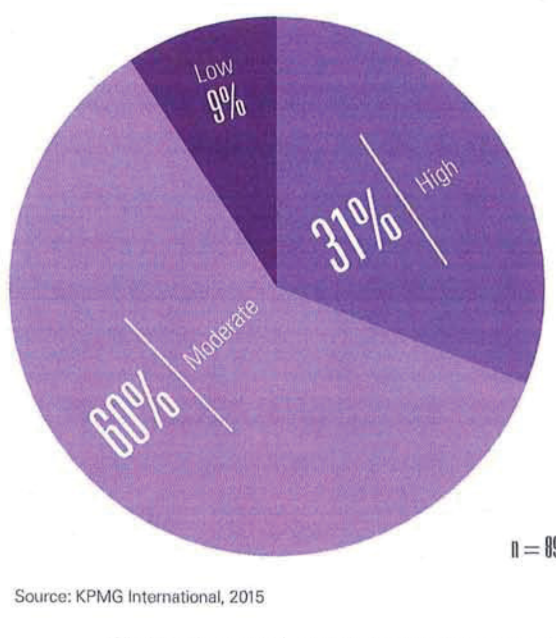


Degree of owner/contractor collaboration over next 5 years



Source: KPMG International, 2015

Level of trust between owner and EPC contractors



Source: KPMG International, 2015

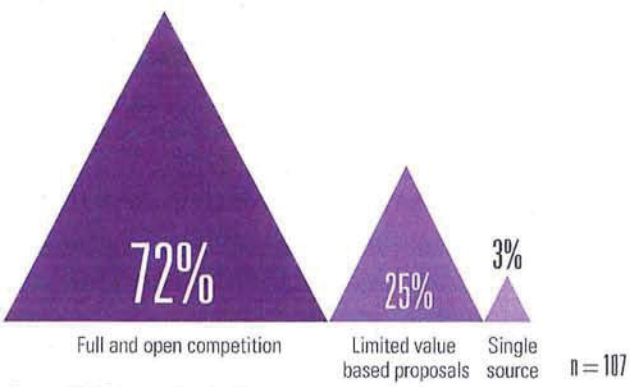
The continued dominance of lump sum (fixed price) contracts underlines the potentially fragile state of owner-contractor relationships. Only the larger organizations involved in the survey embrace other approaches: a quarter use a guaranteed maximum price, while 18 percent adopt a target price with incentives and penalties. A fixed price contract defers risk firmly into the hands of the contractors and does not necessarily foster a collaborative approach.

Seventy-two percent of respondents hold full competitive tenders when awarding contracts, which is another way to maximize risk transfer – and further reflects the lack of trust between owners and contractors. Again, the bigger companies/institutions show a more enlightened attitude, with 34 percent favoring limited value-based proposals, which reward innovation, expertise and quality, and encourage a greater focus on energy efficiency and design excellence.

Most common contracting strategy

Source: KPMG International, 2015

Primary basis for awarding construction contracts



Source: KPMG International, 2015

Respondents believe that the balance of power is tilting towards owners. Just under half say that they expect to have more negotiating strength when delivering capital projects over the next 5 years, which again, does not imply a more open, collaborative mindset. Executives from larger organizations are more likely to believe that contractors hold the balance of power, which could make this group willing to create equitable, win-win relationships, rather than try to exploit their bargaining position.

Only a third of respondents believe they have a high level of trust in their contractors.

Regaining control of mega projects

According to
T.G. Jayanth
Vice President Capital Projects, Suncoke Energy Inc., the scale and uncertainty of the very largest construction projects calls for a different approach and more realistic expectations.

Every engineering procurement and construction (EPC) conference I attend is replete with stories of failed mega-projects. As projects have grown larger and more complex, frequently exceeding several billion dollars in value, the capability to execute them effectively has not kept pace.

One response by owner organizations has been an attempt to "contract your way to project success" by passing risk and therefore liability onto contractors. As evidence of this trend, there are several conferences dedicated exclusively to EPC contract management, focused on various risk-sharing strategies.

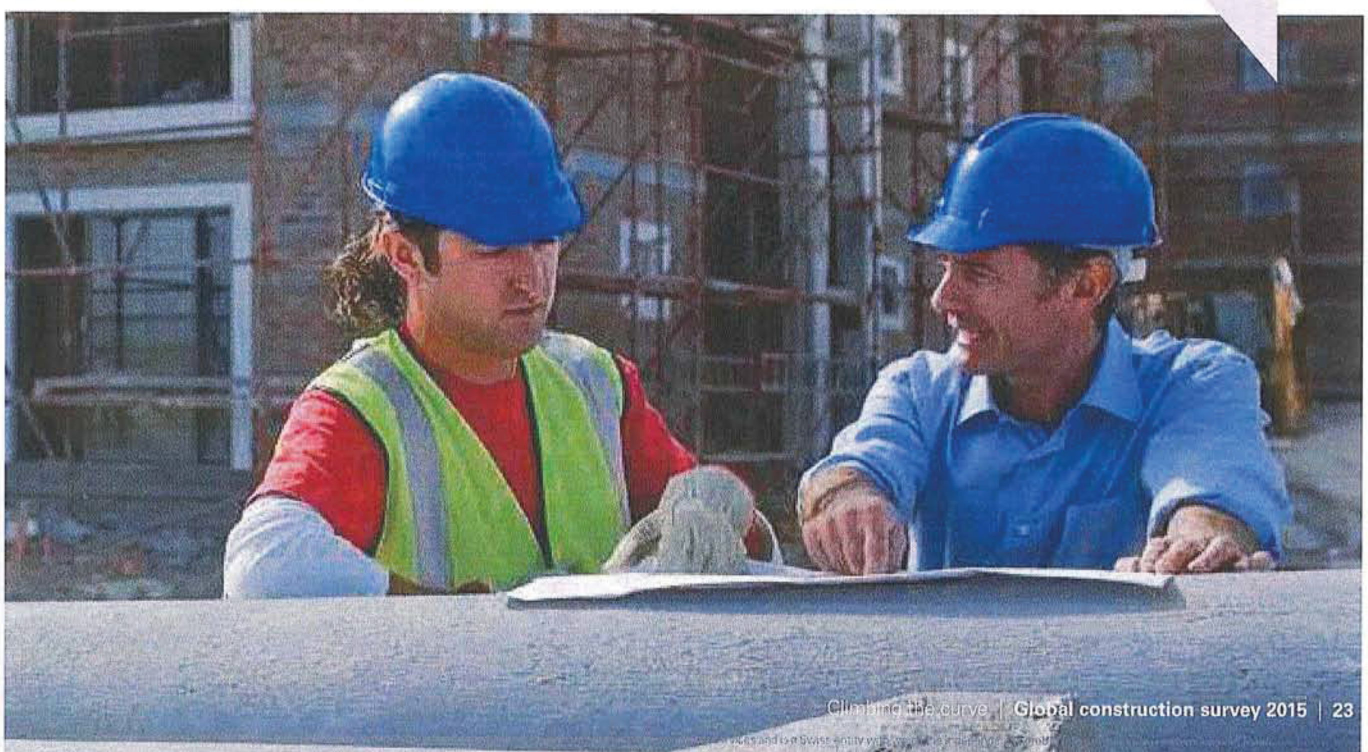
I don't believe that risk-sharing, at least the way it is currently practiced, is a viable long-term solution for mega-projects. Although contractors should be held fully accountable for carrying out their scope of work, all the risks external to the execution should be the *owner's* concern. Transferring these risks to contractors will end up either driving up the bid price (as contractors price in the risk), or potentially deterring contractors from bidding at all. In the extreme, it could drive contractors out of the project business altogether, as they struggle to fully understand and manage risks they are not equipped to deal with. The net result is that owners will end up paying to cover those risks in any case.

Owners may be better advised to fully factor in all risks during the project development phase, and use the increasingly sophisticated risk management tools that are now available, to give their management a realistic picture of the probability of different outcomes. And, with risks identified upfront, project teams have time to seek ways to mitigate them – sometimes with little or no cost impact. Projects should not be approved without a full understanding of the range – and statistical probability – of possible outcomes associated with projects spanning several years.

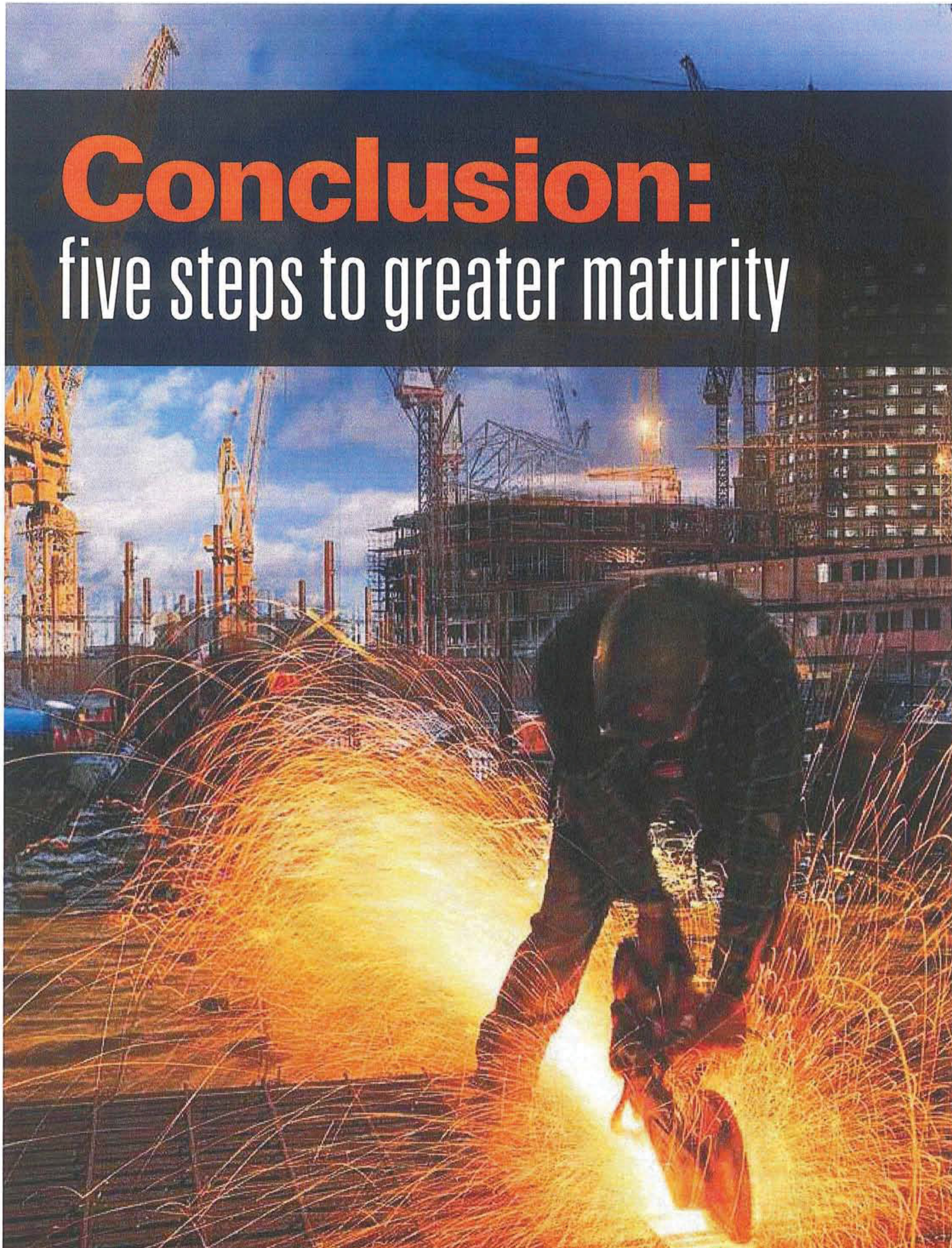
Contract management is important, but good, solid project management and fundamental engineering are arguably even more critical to project success. There is simply no substitute for the meticulous technical and business analysis that's the purpose of the development phase of a project. When this phase needs to be accelerated for business reasons, it is essential to take into account the higher associated risks when estimating return on investment, and ultimately when approving the project.

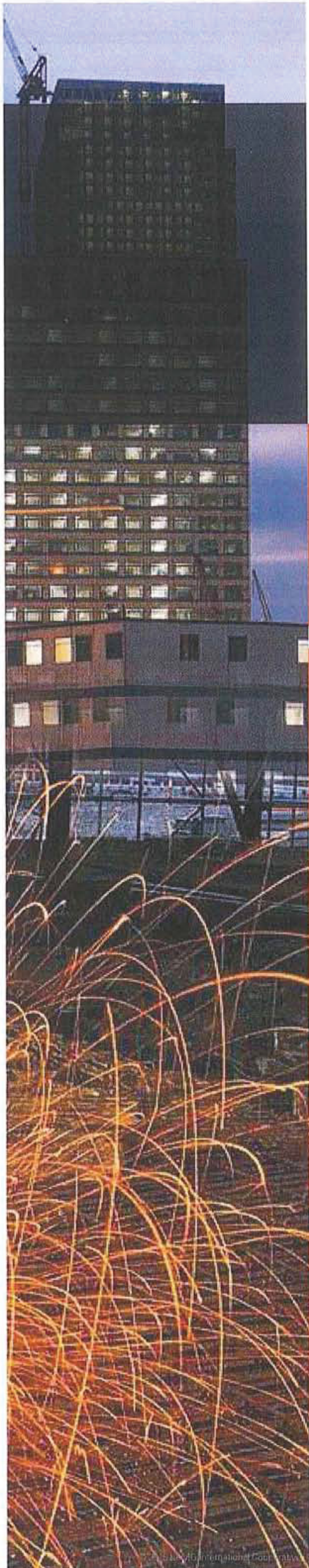
This is especially significant for the increasingly common, multi-billion dollar mega-projects, encompassing global supply chains and spanning multiple geographies. These may take as long as 5 years to complete, during which time steel and energy prices can swing enormously, essential project team members come and go, and stock markets pass through entire cycles, all of which can impact project costs and final product demand. Many of these variations are hard to predict, let alone model even with the best software. In the midst of such uncertainty, it is practically impossible to produce a static forecast of budgets and schedules.

Despite the cautionary note of this commentary, I think the outlook for projects is bright. The good news is that good project management, risk management and engineering practices are receiving growing attention from both owner and contractor companies. This focus on project execution excellence is driving the development of tools, techniques, and training methods that can only improve success rates and reassure our managements of the ability to execute on schedule and on budget.



Conclusion:
five steps to greater maturity





KPMG's 2015 Global Construction Project Owner's Survey reflects the excellent progress made by owners in planning, risk management and execution in recent years. It also highlights a few areas where owners are still striving to improve. As they climb the project management maturity curve, both private and public organizations should consider the following issues:

1

A fresh approach to talent management

An effective recruitment, development and retention strategy should encompass data analytics to help predict future talent needs. And, by widening the net of potential candidates, organizations can attract candidates with new ways of thinking who can augment the existing pool of engineers. Beyond the broadening skills set, there is ultimately no substitute for experience, and owners must find ways to tap into the skill base of older or retiring employees.

2

Integrated project management information systems

The scale and complexity of many of today's construction projects call for swift coordination and real-time reporting. A fully integrated PMIS can keep key stakeholders informed of schedule and cost status, and help enable faster decision-making to keep projects on track.

3

Realism eats optimism for breakfast

Owners should demand practical targets from contractors based upon realistic expectations of what can go wrong. Scheduling needs to balance sufficient slack with targets that stretch – but don't overwhelm. If necessary, owners may seek external scheduling expertise to ensure that they understand the workflow and the full financial impact of delays.

4

Sophistication in contingency

Contingencies should encourage prudent cost management and not be an excuse for overspending. The use of a management reserve acknowledges the potential for uncontrollable risks, while a draw-down approach enables project managers to react quickly and flexibly to situations, while keeping strong control over expenditures.

5

Building an extended team

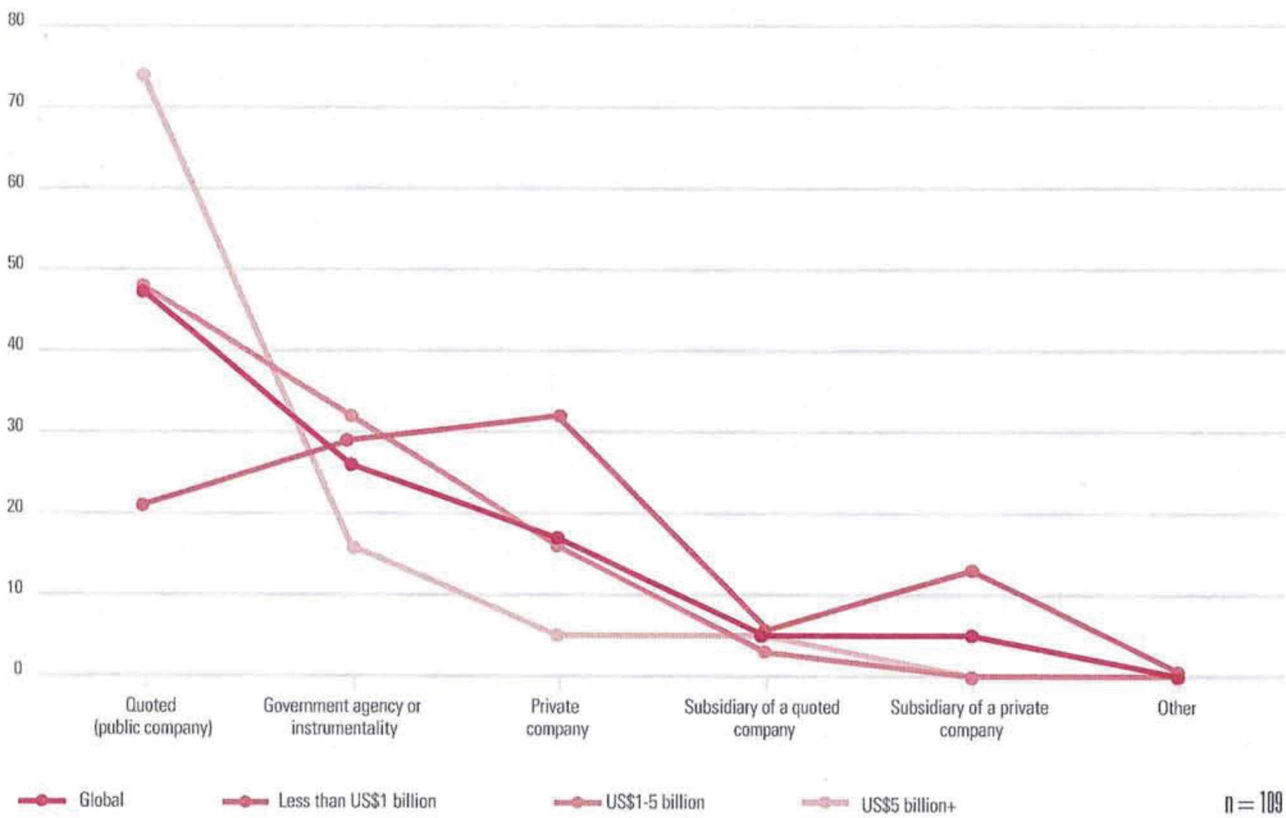
Project owners must invest in relationships with contractors to raise mutual trust and discuss problems or shortcomings. Rather than simply passing all or most of the risk to the contractor, it is preferable to create an integrated project team with common goals and rewards. Where contractors are felt to be lacking in certain skills, owners can discuss how to enhance the team with external expertise.

About the survey

All survey responses were gathered through face-to-face interviews in late 2014 with 109 senior leaders – many of them Chief Executive Officers – from organizations carrying out significant capital construction projects. The interviews were carried out by senior representatives specializing in the engineering and construction industry from KPMG member firms, with the questions reflecting current and ongoing concerns expressed by clients of KPMG member firms.

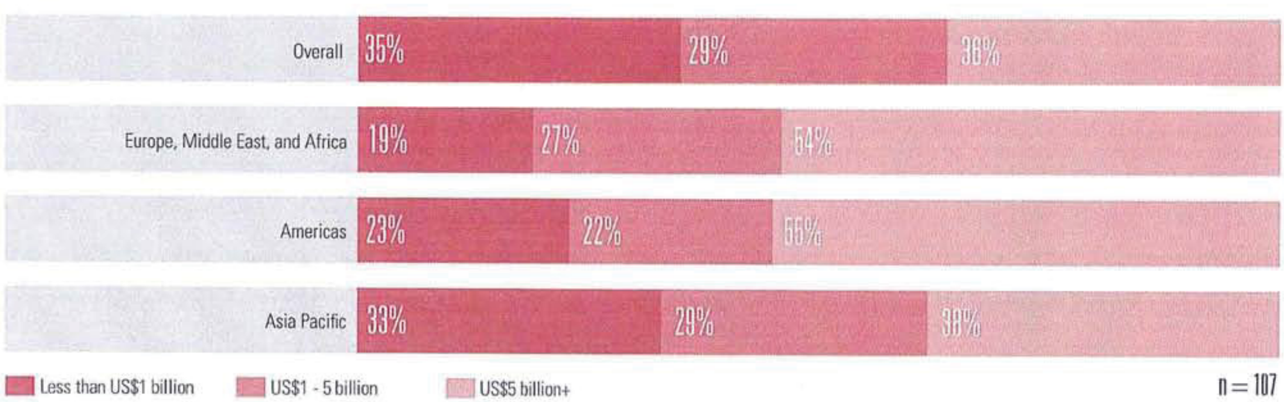
Respondent organizations' turnover/income ranged from less than US$250 million to more than US$5 billion, with a mix of operations from global through regional to purely domestic. The annual capital expenditure budget varied from around US$10 million to over US$5 billion. Twenty-six percent of the respondents' were public bodies – typically government agencies – and some of the main industries represented include energy and natural resources, technology and healthcare.

Entity type



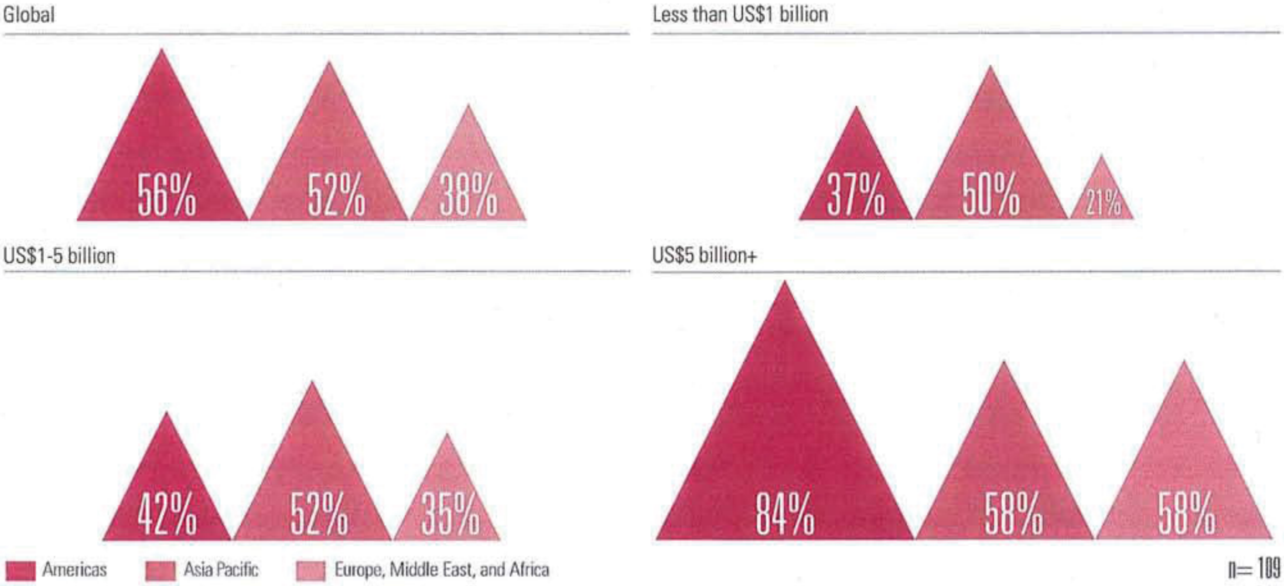
Source: KPMG International, 2015

Annual turnover



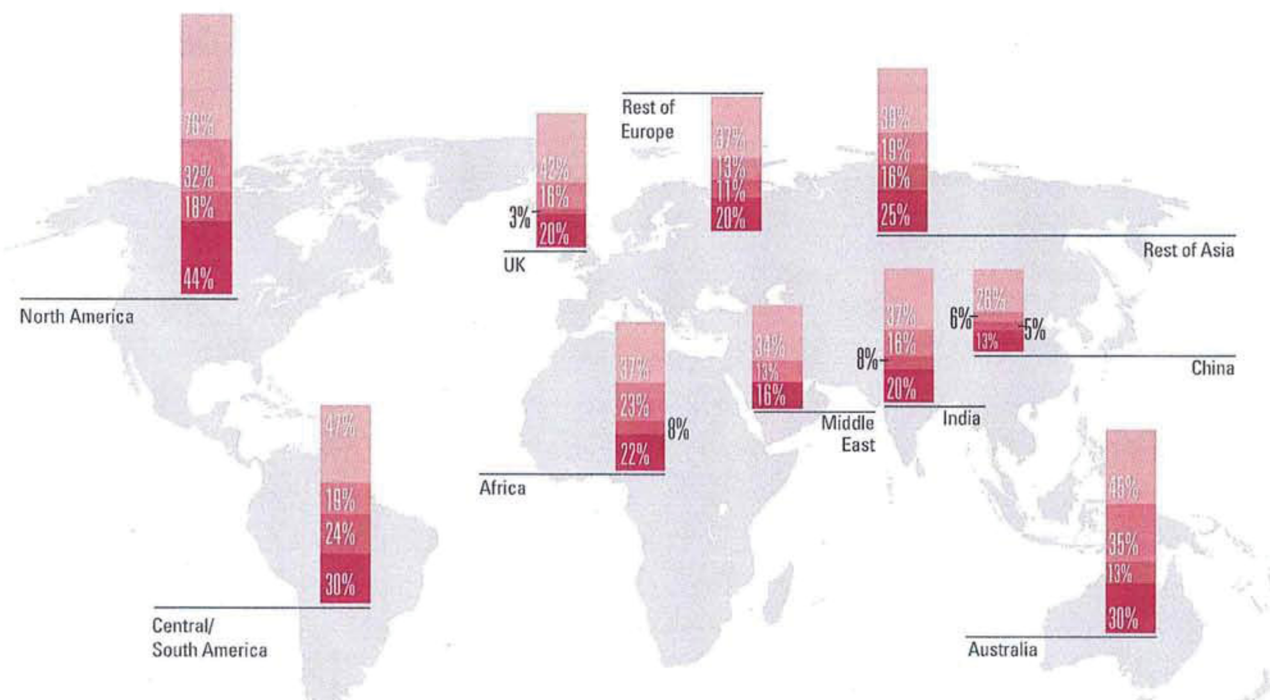
Source: KPMG International, 2015

Regions of operation

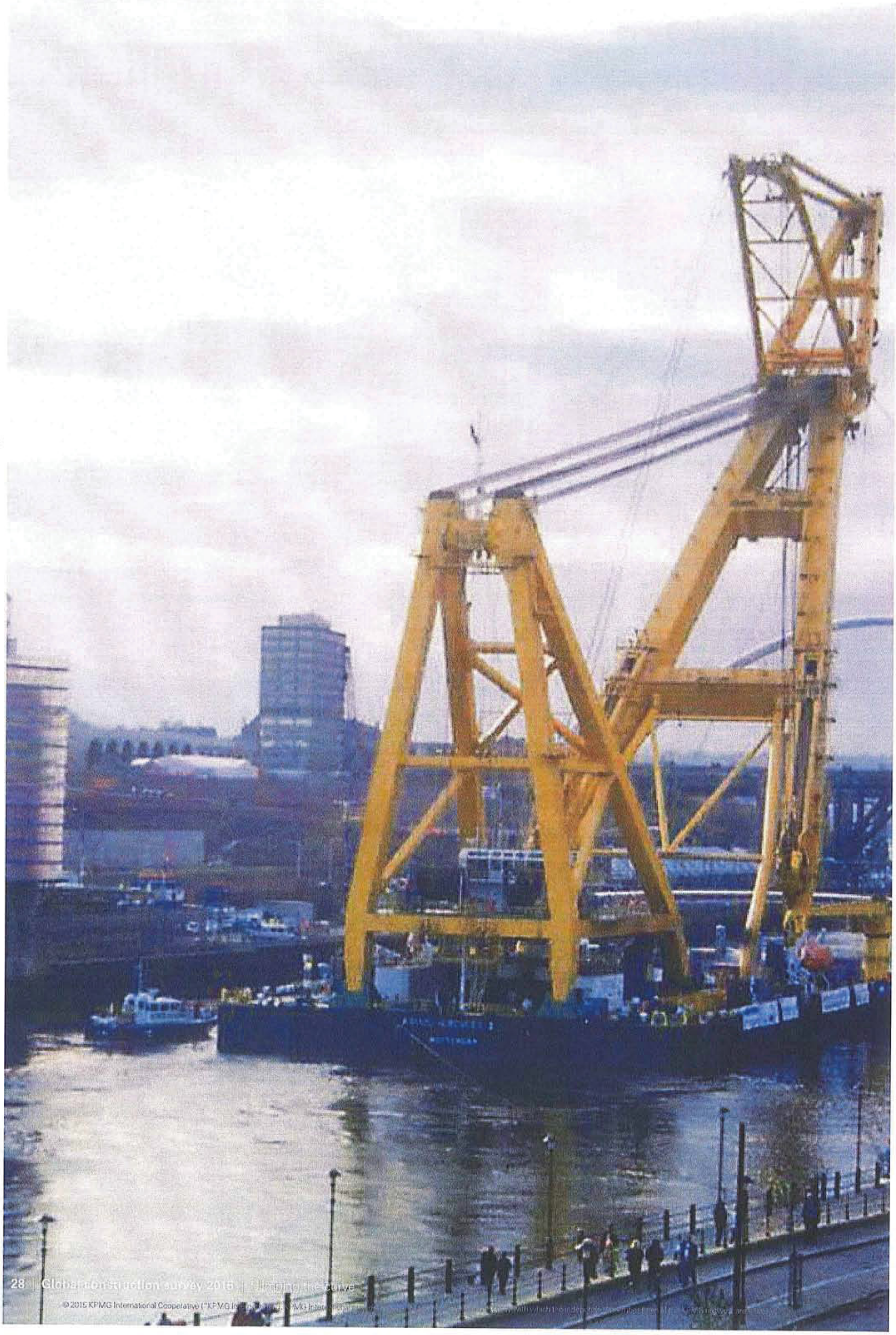


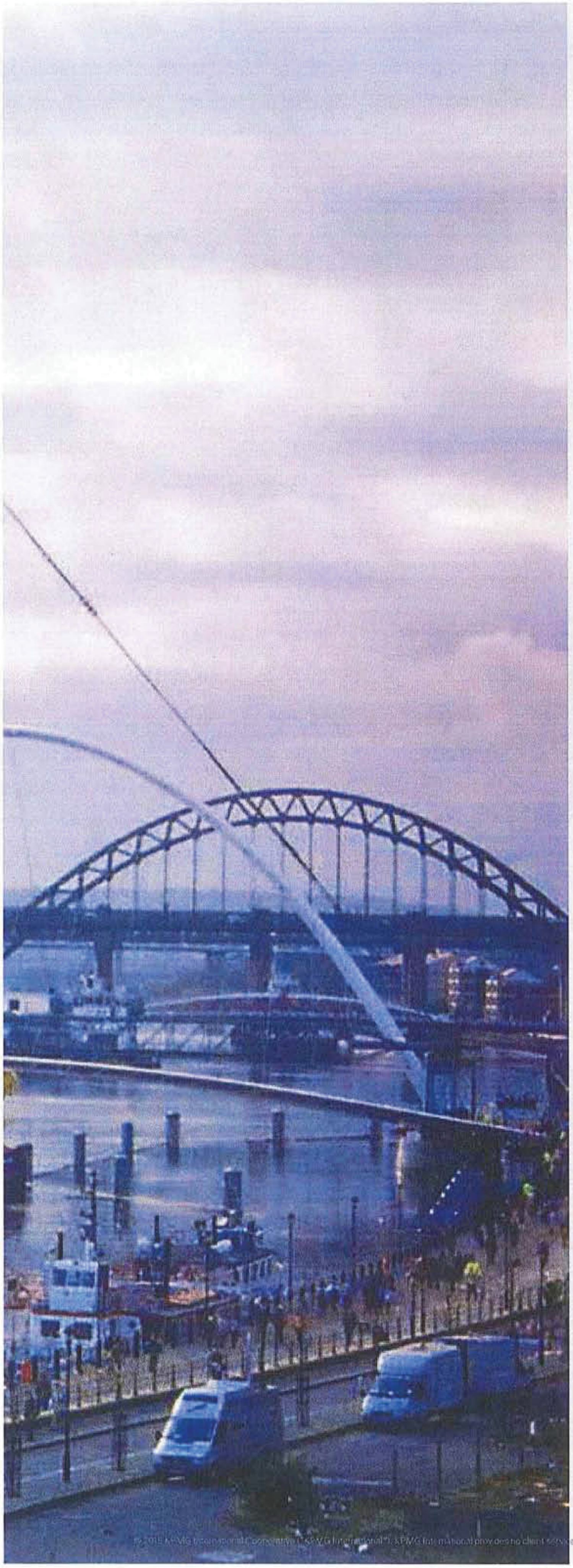
Source: KPMG International, 2015

Sub-regions of operation



Source: KPMG International, 2015





KPMG's global Engineering & Construction experience

Our Building and Construction team is fully committed to serving our clients and understanding their complex and constantly evolving needs.

Our global network enables us to mobilize teams to assist you wherever you are in the world, providing you with access to local and international experience and a tailored service that delivers informed perspectives and clear strategies that our clients and stakeholders value.

Our firms' experienced professionals in audit, tax and advisory bring together a wide range of skills and experience having advised businesses across the globe including developers, contractors, operators, investors, occupiers as well as central, regional and local government organizations on all aspects of the B&C industries.

We can help member firm clients focus on:

Increasing efficiency, through cost optimization, supply chain efficiency and other techniques.

Identifying competitive advantage, by clarifying strengths and weaknesses in your capabilities and producing programs to fill the gaps.

Improve risk management, by refining controls and fostering a culture that embraces and recognizes risk.

Bookshelf

A selection of relevant KPMG reports and insights. To access these publications, please visit: **www.kpmg.com/building** or email us at: **gofmbuilding@kpmg.com**

Global Construction Surveys

KPMG conducts the Global Construction Survey to monitor Engineering & Construction issues and provide timely summaries and insights to help professionals make more informed business decisions in today's rapidly changing environment – this is the eighth edition of the KPMG Global Construction Survey.

2013 Global Construction Survey: Ready for the next big wave?

The 2013 report catches the industry in a more upbeat mood after gauging the views of 165 senior executives of leading Engineering & Construction firms from around the world to determine industry trends and opportunities for growth.

2012 KPMG Global Construction Survey:The great global infrastructure opportunity

The 2012 survey focuses on the insatiable demand for energy and infrastructure in all forms, and the resulting fundamental shifts in focus for nearly all E&C firms.

2010 KPMG Global Construction Survey: Adapting to an uncertain environment

The latest survey highlights the cautiously optimistic outlook of many E&C companies about their immediate prospects and discusses key industry issues and the measures adopted to seize the new opportunities identified.

2009 KPMG Global Construction Survey: Navigating the Storm: Charting a Path to Recovery?

More than 100 senior executives from the Engineering & Construction industry responded to this survey, which focused on how organizations were weathering the impact of the global financial crisis.

Other Thought Leadership

KPMG's Engineering and Construction, Major Projects Advisory, and Infrastructure professionals conduct research and develop thought leadership for clients and industry leaders. This information on current issues facing contractors and owners in a rapidly changing construction environment provides key insights and tangibly contributes to their decision-making processes.

Preventing black swans: Avoiding major project failure

This paper highlights characteristics of major capital projects that can lead to catastrophic failure for owners and contractors, alternative approaches for screening projects, and red flags and triggers for early identification of troubled projects.

How to successfully manage your mega-project

Effective management of mega-projects relies on three key concepts: early planning and organizing, stakeholder communication and project controls integration, and continuous improvement. This three part series covers best practice for managing mega-projects.

Integrated project delivery: Managing risk and making it work for all parties

This paper provides an overview of the current practices and challenges involving IPD and its evolving risk profile. It also offers guidance on how to prepare an IPD strategy and describes the tools and methodologies currently used to facilitate successful IPD.

Next wave: Continuous monitoring and compliance

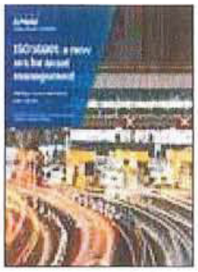
This report reviews the framework for developing a continuous project monitoring and compliance program that integrates the positive features of project performance monitoring, project risk and controls monitoring, and computer aided auditing.

Preventing fraud in overseas construction projects

Over the last decade, construction companies have increasingly recognized the imperative of geographic diversification and international expansion and while there are many benefits to investing in emerging markets, the risk of bribery and corruption may be even greater.

Project portfolio optimization: Do you gamble or take informed risks?

This paper addresses portfolio optimization by highlighting some of the challenges and pitfalls of inefficient capital allocation by providing example approaches and practices for identifying and managing projects throughout the life cycle.



ISO 55001: A new era for asset management

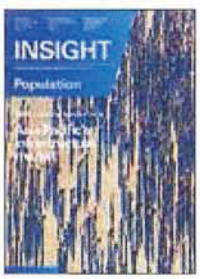
This paper discusses the benefits of an integrated holistic approach to asset management, looks at the requirements of ISO 55001 and explains how companies comply with the standard and improve asset performance.

Infrastructure 100: World Markets Report

In the third Infrastructure 100, KPMG highlights key trends driving infrastructure investment around the world and a global panel of independent industry experts identify 100 of the world's most innovative, impactful infrastructure projects.

Insight – The Global Infrastructure Magazine

Insight is a semi-annual magazine that provides a broad scope of local, regional and global perspectives on many of the key issues facing today's infrastructure industry.



Issue No. 6 – Population

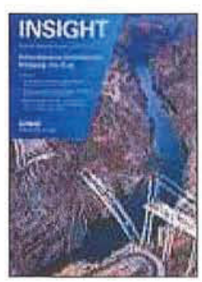
This edition of Insight takes a closer look at the link between unprecedented population changes and demographic shifts currently underway and the infrastructure needed to meet these challenges. It also includes a Special Report on Asia Pacific's infrastructure market.

Issue No. 5 – Resilience

This edition of Insight explores some of the world's most impactful stories of resilience. It also includes an exciting Spotlight Special Report on the important changes and opportunities within Latin America's infrastructure market.

Issue No. 4 – Megaprojects

This edition of Insight magazine explores some of the key challenges and opportunities impacting megaproject deliver, and includes a Spotlight Special Report on Africa's infrastructure market, a key growth area.



Issue No. 3 – Infrastructure Investment: Bridging the Gap

This edition explores the complex world of infrastructure finance and funding, including critical topics ranging from direct investment, to innovative financing and funding models, and the evolving infrastructure fund market.

MPA Project Leadership Series

KPMG's Major Projects Advisory (MPA) Project Leadership Series is targeted toward owners with major construction programs, but its content is applicable to all entities or stakeholders involved with construction projects. This series describes a framework for managing and controlling large capital projects based on the experience of professionals from KPMG's MPA practice. They provide services to hundreds of leading construction owners, and engineering, procurement and construction contractors.

- From Concept to Project – Critical Considerations for Project Development
- Stakeholder Management and Communication
- Project Organization & Establishing a Program Management Office
- Governance and Project Controls
- Budgeting, Estimating and Contingency Management
- Monitoring Capital Projects and Addressing Signs of Trouble
- Project Risk Management (future)
- Investing in Tools & Infrastructure (future)

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For further information, please visit us online at **kpmg.com/building**, email: **gofmbuilding@kpmg.com** or contact the appropriate geographic lead:

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KPMG's 2015 Global Construction Survey would not have been possible without contributions from Clay Gilge, Brian Relle, Randy Meszaros, Kevin Max, Jeffrey Kagan and Dane Wolfe.

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Designed by Evalueserve.

Publication name: Climbing the curve

Publication number: 132253-G

Publication date: March 2015

EXHIBIT D

PIPELINE SAFETY AND ENHANCEMENT PLAN (PSEP)
2016 REASONABLENESS REVIEW – A.16-09-005
WORKPAPERS
TABLE OF CONTENTS

Summary

Table 1: Summary of L-406 Replacement and Hydrotest Projects

Project Name	L-406 Replacement (Sections 1, 2A, 4 and 5) and Hydrotest (Section 2) Project
WOA Number / Date:	25374 and 91050 / May 19, 2014
Section1 (Replacement)	91050.001 / May 19, 2014
Section 2 (Hydrotest)	91050.002 and 25374.002 / May 19, 2014
Section 2A (Replacement)	91050.003 / May 19, 2014
Section 4 (Replacement)	91050.001 / May 19, 2014
Section 5 (Replacement)	91050.001 / May 19, 2014
Cities:	
Section1 (Replacement)	Ventura
Section 2 (Hydrotest)	Camarillo
Section 2A (Replacement)	Thousand Oaks
Section 4 (Replacement)	Encino
Section 5 (Replacement)	Somis
Original Pipe Diameter/New Diameter	[redacted]
Construction Start / Finish:	
Section1 (Replacement)	August 4, 2014 /January 9, 2015
Section 2 (Hydrotest)	October 20, 2014 / March 11, 2015
Section 2A (Replacement)	October 20, 2014 / March 11, 2015
Section 4 (Replacement)	August 11, 2014 / September 23, 2014
Section 5 (Replacement)	August 11, 2014 / September 24, 2014
Loaded Capital Costs	$ 7,255,313
Loaded O&M Costs	$ 3,220,138
Total Loaded Project Costs	$10,475,451
Disallowance	$ 0

Background

L-406 is an approximately 51.47 mile high pressure transmission line of primarily [redacted] pipe that traverses the cities of Ventura, Somis, Camarillo, Thousand Oaks, and Woodland Hills, terminating in Encino. To better manage the planning and construction efforts, as well as lessen the customer impact, L-406 was divided into six sections, four replacement sections and two hydrotest sections in order to optimize planning and construction efforts. Five of the sections will be presented in this workpaper: Sections 1, 2, 2A, 4, & 5. Section 3 was re-scoped following an additional review that changed the project from a replacement to a hydrotest project and will be presented as separate workpaper in a later filing. Although preliminary engineering and design activity occurred related to Section 3, it is not described in this workpaper. This workpaper will describe Sections 1, 2, 2A, 4, and 5.

Description

Through the L-406 Replacement (Sections 1, 2A, 4, and 5) and Hydrotest (Section 2) Project, SoCalGas and SDG&E enhanced its high-pressure transmission pipeline system by successfully replacing approximately 1,000 feet of pipe and hydrotesting over 1 mile of pipeline, as shown in Figures 1 through 12 and Table 2 that describes the project scope as of the 2011 PSEP filing and the final construction mileage.

Examples of cost avoidance actions included:

- Through early stage scope validation Category 4 Criteria mileage was reduced from 7.863 mi. to 0.518 mi.
- L-406 Section 2 expanded test scope to accelerate a long stretch of Phase 2 pipe realizing efficiencies by avoiding future work on the pipeline.
- L-406 Section 2A work was expedited to coincide with L-406 Section 2 and eliminated 1 mobilization and demobilization in Phase 2.

- L-406 Section 4 was accelerated into the Pipeline Integrity project that was already in construction.

Construction began in August 2014 and this series of projects was completed in March 2015. The L-406 Replacement and Hydrotest Project incurred a total loaded project cost of $10,475,451.

Table 2: L-406 Replacement and Hydrotest Projects 2011 Filing and Final Mileage*

Line 406	Total Mileage (miles)	Criteria Mileage	Accelerated Mileage**	Incidental Mileage
2011 PSEP Filing	20.700 mi	7.863 mi	12.838 mi	0.000
Final Project Mileage				
Section 2 (Hydrotest)	0.980 mi	888 ft.	0.809 mi.	16 ft.
Section 1 (Replacement)	772 ft	670 ft	102 ft	0
Section 2A (Replacement)	36 ft	0	31 ft	5 ft
Section 4 (Replacement)	45 ft	43 ft	0	2 ft
Section 5 (Replacement)	130 ft	100 ft	0	30 ft
Total	1.166 mi.	0.322 mi.	0.834 mi	53 ft.

**Values may not add to total due to rounding.*

***Accelerated mileage includes Phase 1B and Phase 2 pipe. Phase 2 includes pipelines without sufficient record of a pressure test in less populated areas (Phase 2A) or pipelines with record of a pressure test, but without record of a pressure test to modern – Subpart J – standards (Phase 2B). Included in this project was 0.834 miles of pipe accelerated from Phase 2A. The accelerated mileage was included to realize efficiencies and to enhance project constructability.*

Figure 1: Overview Map of L-406 Replacement and Hydrotest Projects

Figure 2: Satellite Image of Overview Map of L-406 Replacement and Hydrotest Projects

Figure 3: Overview Map of L-406 Section 1 Replacement Project

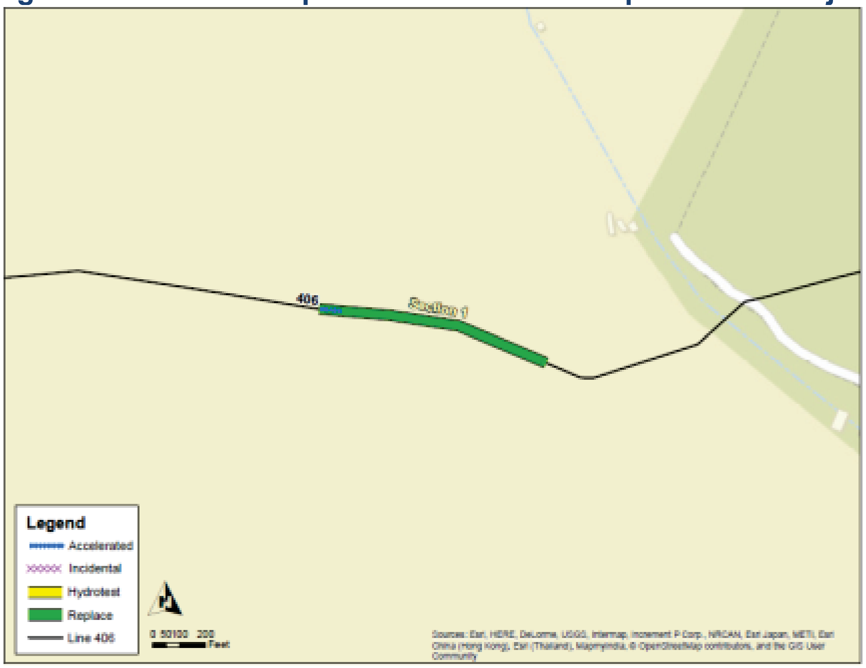

Figure 4: Satellite Image of L-406 Section 1 Replacement Project

Figure 5: Overview Map of L-406 Section 2 Hydrotest Project

Figure 6: Satellite Image of L-406 Section 2 Hydrotest Project

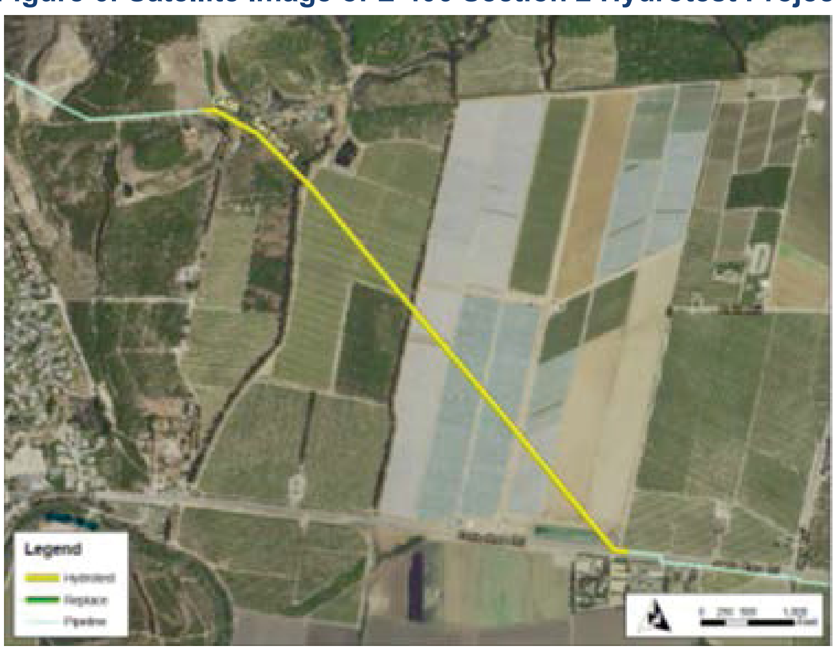

Figure 7: Overview Map of L-406 Section 2A Replacement Project

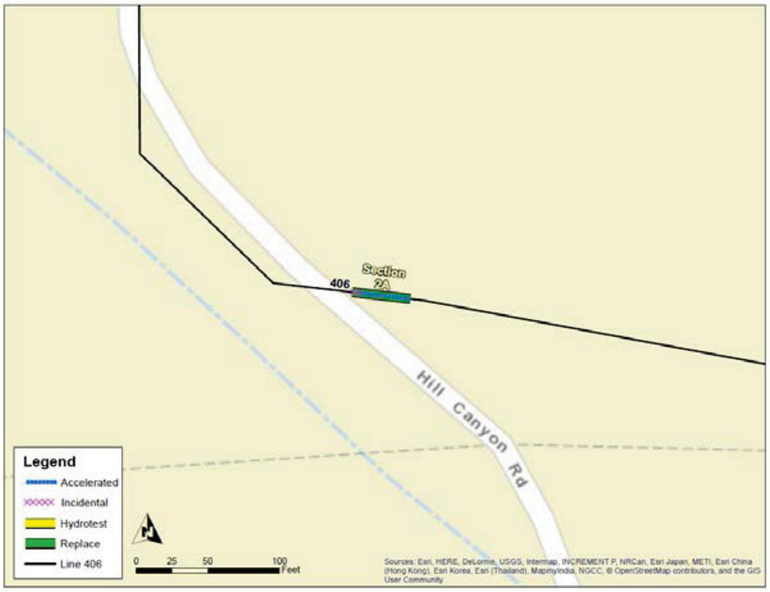

Figure 8: Satellite Image of L-406 Section 2A Replacement Project

Figure 9: Overview Map of L-406 Section 4 Replacement Project

Figure 10: Satellite Image of L-406 Section 4 Replacement Project

Figure 11: Overview Map of L-406 Section 5 Replacement Project

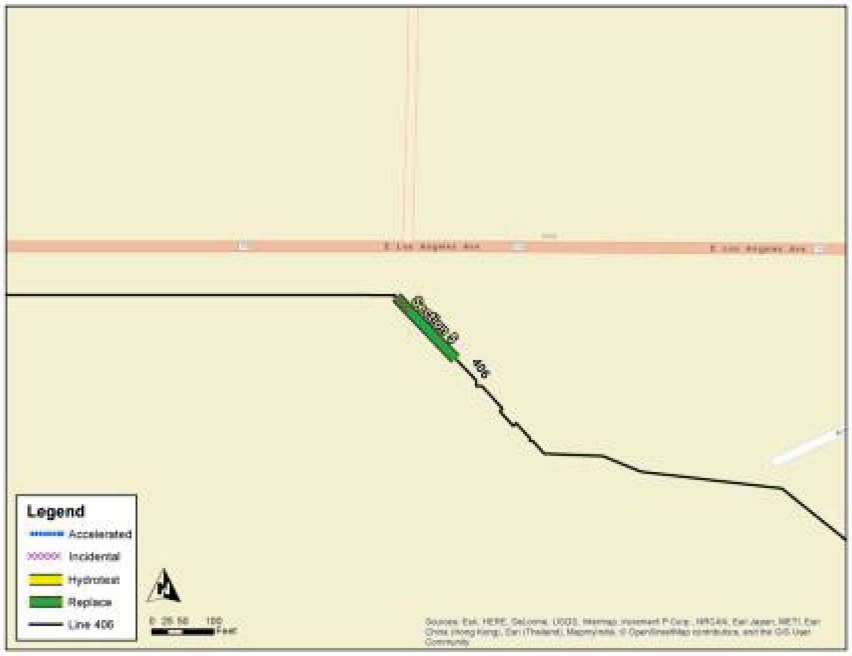

Figure 12: Satellite Image of L-406 Section 5 Replacement Project

Stage 1 – Project Initiation

In workpapers supporting the 2011 PSEP filing,[1] SoCalGas and SDG&E identified L-406 as a Phase 1A, 20.70 mile hydrotest project, of which 7.863 miles was Category 4 Criteria.

During Stage 1, SoCalGas and SDG&E completed scope validation analysis of L-406 and verified a scope reduction of 7.863 miles to 0.518 miles of Category 4 Criteria mileage.

[1] See December 2, 2011 Amended Pipeline Safety Enhancement Plan (PSEP) of SoCalGas and SDG&E.

Stage 2 – Analysis and Findings

During Stage 2, records were analyzed to further refine the scope and determine the selection of pressure testing or replacement to confirm the Decision Tree outcome.

L-406 was filed in the PSEP as a strength test.

Engineering Factors

Sections 1, 2A, 4, and 5

Based on the PSEP Decision Tree, SoCalGas and SDG&E confirmed that L-406 Sections 1, 2, 2A, 4 and 5 should commence as replacement projects. The PSEP Decision Tree directs that scope less than 1,000 feet should be replaced because, under most circumstances, replacements will be the cost effective option. In this instance there were no conditions that justified overriding this guidance.

The total Category 4 mileage for each replacement section was identified as follows:

Section 1: 772 feet

Section 2A: 31 feet

Section 4: 43 feet

Section 5: 100 feet

Sections 1, 2A, 4 and 5 were confirmed as replacement projects because the scope of each project was less than 1,000 feet. In addition, Section 4 was adjacent to a planned Pipeline Integrity replacement project which could be cost effectively expanded to include this section of PSEP pipe.

Section 2

- Criteria mileage within Section 2 was 888 feet. However, there was Category 4 non-criteria pipe adjacent to the 888 feet that would need to be addressed in Phase 2. The project was expanded to include the accelerated mileage and create one long hydrotest, eliminate one gas blowdown, and reduce PSEP program costs.
- Section 2 is a 5,157 ft. (0.977 mi) section that was confirmed as a hydrotest project because it was greater than 1,000 feet, had manageable customer impacts, and no significant engineering factors supporting replacement. Accelerated mileage was incorporated to capture efficiencies.

Stage 3 – Initial Planning and Design

During Stage 3, SoCalGas and SDG&E developed a Phase 2 WOA estimate and began field surveys to complete preliminary design drawings and further refine scope.

In addition to the schedule and estimate, other key activities include identifying all permits, TRE's, and easements, defining long lead materials and pricing, understanding customer impacts and interruptions, and preparing any necessary environmental submittals.

Planning and Design Activities

Project Specific Initial Planning and Design Assumptions are described below for each Section:

Section 1 - Replacement Project

This section starts in the hills north of Ventura by Barlow Canyon Road. The section extends east, ending just west of the baseball fields at Arroyo Verde Park.

Additional Considerations

- Construction would be completed within 3 months if system capacity permitted.
- Permits may not be granted in a timely manner; given the known delays being experienced in this area.
- Daytime construction, 5 days a week, with no overtime.
- One mobilization/demobilization.

Section 2 - Hydrotest Project

- This test location will begin north of Quito Park on Hilltop Lane in Camarillo and extend to Santa Rosa Road and will include approximately 888 feet of Category 4 Criteria pipe with an additional 4,269 feet of Phase 2 accelerated pipe.

Additional Considerations

- Due to the end point of the criteria section being in farm land, the project design was extended to a location next to a road, which added incidental mileage.
- The schedule would need to be coordinated with the shut-in schedule of a power plant.
- Agency permits may not be granted in a timely manner given the known delays being experienced in this area.
- It was anticipated that construction could proceed more quickly in an agricultural area and site restoration would be less costly.
- Daytime construction.
- Negotiations are needed to obtain 2 TREs for installation of the test heads on private property.
- One mobilization/demobilization.

Section 2A - Replacement Project

A short segment of Phase 2 Category 4 pipe was identified within the shut-in and gas blow down limits for Section 2, thus Section 2A was replaced during this shut-in to eliminate a future blowdown and shut-in. Sections 2 and 2A are over 1-mile away from each other.

Additional Considerations

The work would be in a non-congested area for excavation.

- Daytime construction.
- A TRE would be needed from the City of Thousand Oaks Public Works Department.

Section 4 - Replacement Project

Section 4 was initiated earlier as it was immediately adjacent to a Pipeline Integrity (PI) ILI project which was easily expandable to include the PSEP scope of 43 ft. of Category 4 mileage. This allowed PSEP to complete this project with significant cost savings and the reduced community and system impact of a second construction project.

Section 5 - Replacement Project

Section 5 consisted of 130 feet to be replaced with one mobilization/demobilization and daytime construction. This also required removal of coal tar wrap and asbestos abatement of existing pipe (see figure 13).

Estimate of Costs

The estimate was prepared on May 19, 2014 using the Stage 3 SCG Pipeline Estimate Template Rev 0 estimating tool and was based on preliminary design. In Table 3, the Phase 2 WOA estimate includes forecasted loaded costs for 5 sections of L-406 (Sections 1, 2, 2A, 3, and 5) and was created as a single parent Work Order Authorization (WOA). Note that the Phase 2 WOA estimate (Table 3) includes costs for Section 3, which was subsequently re-scoped to a later date, and does not include costs for Section 4.

Table 3: L-406 Phase 2 WOA Estimate

Cost Category	Phase 2 WOA
Company Labor Costs	$ 1,225,987
Contract Costs	$ 4,970,089
Material Costs	$ 1,177,627
Other Direct Cost	$ 5,231,923
Total Direct Costs	$ 12,605,626
Total Indirect Costs	$ 2,571,491
Total Loaded Costs	$ 15,177,117

The direct costs estimates broken out for Section 1, 2, 2A and 5 are shown in Table 4 below. An estimate was not prepared for Section 4.

Table 4: Stage 3 Direct Cost Estimate L-406

Cost Category	Section 1	Section 2 & 2A	Section 5	Stage 3 Estimate- 1, 2, 2A, 5
Company Labor Costs	$ 299,297	$ 314,834	$ 124,994	$ 739,125
Contract Costs	$ 1,141,587	$ 1,340,388	$ 431,659	$ 2,913,634
Material Costs	$ 346,958	$ 254,851	$ 225,410	$ 827,219
Other Direct Costs	$ 1,265,393	$ 1,564,116	$ 533,888	$ 3,363,397
Total Direct Costs	$ 3,053,235	$ 3,474,188	$ 1,315,951	$ 7,843,374
Total Indirect Costs	N/A	N/A	N/A	N/A
Total Loaded Costs	N/A	N/A	N/A	N/A

Stage 4 – Detailed Planning and Design and Procurement

During Stage 4, detailed design and material procurement was completed in order to provide a construction ready packet to the construction contractor to execute the planned project scope.

SoCalGas performed the following detailed engineering design and contractor selection actions to prepare for project construction:

- Progressed design drawings to an Issued for Construction (IFC) package.
- Acquired pothole information.
- Ordered the remaining material through PSEP Supply Management.
- Provided all required documentation in accordance with PSEP processes.

Detailed Planning and Design

At Stage 4, the scope for engineering design for this project remained unchanged from Stage 3 for the five sections that are the subject of this workpaper; however, Section 3 was re-scoped and became a separate project that will be submitted in a future reasonableness review application.

Construction Contractor Selection

Section 1, 2, 2A, and 5

Construction of L-406 Section 1, 2, 2A, and 5 was awarded to the Performance Partner.

Construction of L-406 Section 4 was included in the existing Pipeline Integrity ILI retrofit project; and therefore was excluded from the Performance Partner's scope of work for L-406.

The Performance Partner/Construction Contractor final TPE for Sections 1, 2, 2A and 5 was [redacted] which is [redacted] more than the Stage 3 construction contractor direct estimate of [redacted] that was used to develop the Phase 2 WOA estimate.

Section 4

The construction contractor that was selected by Pipeline Integrity through a competitive bid process also completed Section 4 for PSEP.

Stage 5 – Construction

Schedule

Section 1

Construction Start Date: 08/04/2014

NOP Date: 09/19/2014

Construction Finish Date: 01/09/2015

Construction duration was planned for 4 weeks and actual was 22 weeks.

Sections 2 and 2A

Construction Start Date: 10/20/2014

NOP Date: 12/13/2014

Construction Finish Date: 03/11/2015

Construction duration was planned for 4 weeks and actual was 17 weeks.

Section 4

Construction Start Date: 08/11/2014

NOP Date: 09/19/2014

Construction Finish Date: 09/23/2014

Construction duration was planned for 6 weeks and actual was 6 weeks.

Section 5

Construction Start Date: 08/11/2015

NOP Date: 09/19/2014

Construction Finish Date: 09/24/2015

Construction duration was planned for 6 weeks and actual was 6 weeks.

Field Conditions

Section 1

Site Conditions:

- A steep incline and sandy terrain at the site location prevented the allotted 4,000-gallon water truck from covering all areas on site required for dust control, fire control, and mitigation efforts. A second water truck with necessary driving capabilities (6x6, 4 wheel drive) was needed to reach all areas of site location and achieve full coverage.
- Additional site security was needed for the construction areas due proximity to a highly populated location.

Constructability Issues:

- The original design called for a [redacted] test head assembly; however, a [redacted] test head was not available and a [redacted] test head assembly was used instead. Construction Contractor crews modified the test head launcher and receiver to accommodate the [redacted] test head, thus allowing de-water and pipe drying portion of the work to proceed on schedule.

Site Restoration:

- Trench excavation was more extensive than planned due to instability of the steep slope and poor soil conditions.
- After Section 1 work was completed, it was determined that additional land restoration was required because the amount of vegetation cleared was larger than planned to accommodate construction. Hydro-seeding and installation of erosion control took an additional 2 weeks to perform.

Sections 2 and 2A

Constructability Issues:

- A damaged portion of the pipeline was discovered when the pipe was exposed and needed to be replaced prior to strength testing. This resulted in lengthening the excavation to accommodate cutting out the damaged portion of the pipe.

Weather:

- Inclement weather resulted in delays in restoration, moving off of the laydown yard, and the repair of the access road.

Section 4

There was none of note.

Section 5

There was none of note.

Figure 13: Exposed pipe on Section 5 with protective wrap in preparation for removal and asbestos abatement

Stages 6 and 7 – Commissioning and Closeout

Commissioning activities included site restoration, final inspections, and placement of the pipeline back into service, transportation and disposal of the hydrotested water or hazardous material and demobilization from the site. Close out activities included development of final drawings, the reconciliation package and updates to company systems to reflect the changes made to the system.

Cost Variance

Table 5: L-406 Phase 2 WOA, Direct Estimate and Actual Costs

COST SUMMARY					
	PHASE 2 WOA	Estimate of Section 1, 2, 2A, 5	O&M (actuals)	CAPITAL (actuals)	Delta from Estimate over/(under) Difference between directs for sections worked as compared to actuals
COMPANY LABOR	$ 1,225,987	$ 739,125	$ 96,786	$ 296,763	$ (345,576)
CONTRACT COSTS	$ 4,970,089	$ 2,913,634	$ 1,985,423	$ 3,871,332	$ 2,943,121
MATERIALS	$ 1,177,627	$ 827,219	$ 15,785	$ 155,508	$ (655,926)
OTHER DIRECTS	$ 5,231,923	$ 3,363,397	$ 933,484	$ 2,300,876	$ (129,037)
TOTAL DIRECTS	$ 12,605,626	$ 7,843,375	$ 3,031,477	$ 6,624,480	$ 1,812,582
INDIRECTS	$ 2,571,491		$ 188,662	$ 630,833	
TOTAL LOADED	$ 15,177,117		$ 3,220,138	$ 7,255,313	

Table 5 shows the Phase 2 WOA (Sections 1, 2, 2A, 3, and 5) estimate and the March 2016 loaded actual costs (Sections 1, 2, 2A, 4, and 5). As discussed above, the Phase 2 WOA includes the estimated costs for Section 3 that was later re-scoped from this project after the estimate was created. This table also compares the direct cost estimate for Sections 1, 2, 2A, and 5 and the direct actual costs for Sections 1, 2, 2A, 4 and 5. The difference between the direct cost estimate and the direct actual cost is $1,812,582 for O&M and Capital.

The above variance is attributable to scope changes and unanticipated conditions that occurred after the Phase 2 WOA (including: incline and terrain necessitating a second water truck; modification to the test head launcher and receiver; extensive trench excavation; scope expansion to address damaged pipe; inclement weather; and additional site restoration work), an early cost estimating tool and process that was based on preliminary project designs (resulting in underestimation of construction contractor costs, inspection costs, and close out costs), and Pipeline Integrity handling the Section 4 replacement work (as a result, the Section 4 replacement was not included in the WOA estimate, but actuals of approximately $354,000 are included). These increased costs were reasonably incurred to complete the project, but were not accounted for in the Stage 3 estimate.

Disallowances

There was no disallowance for line L-406 Replacement and Hydrotest Projects as there were no post-1955 segments included in the project without records that provide the minimum information to demonstrate compliance with industry standards or regulatory strength testing and recordkeeping requirements then applicable.

Conclusion

SoCalGas and SDG&E enhanced the safety of their natural gas system by prudently executing the L-406 Hydrotest and Replacement Projects. Through this project, SoCalGas and SDG&E successfully replaced 1,000 feet of pipe and hydrotested over 1 mile of pipeline of L-406. The project incurred a total loaded project cost of $ 10,475,451 for O&M and capital.

SoCalGas and SDG&E executed this project prudently: dividing the project into sections to better manage the planning and construction efforts and lessen customer impacts; engaging in prudent cost avoidance efforts; minimizing impacts to customers and the community; coordinating work with Pipeline Integrity; coordinating work across the different sections; and responding to unknown field conditions and scope changes.

SoCalGas and SDG&E's total loaded project cost of $10,475,451 for O&M and capital is reasonable and should be approved. SoCalGas and SDG&E engaged in prudent cost avoidance efforts (reduced scope through scope validation efforts; realized efficiencies by accelerating a long stretch of Phase 2 pipe; expediting work to enable better coordination and improve efficiencies); engaged in reasonable efforts to promote competitive and market-based rates for contractor services and materials (see Chapter II (Phillips) (approximately 98% of PSEP agreements with contractors and suppliers were either competitively bid or through agreements entered into using market-based rates based on a recent competitive sourcing event)); and used a reasonable amount of company and contractor resources given the project's complexity (multiple projects across a large area – including populated areas requiring traffic control and additional site security – that required coordination within PSEP and with Pipeline Integrity; work on an incline with difficult terrain) and work scope changes (modification to the test head launcher and receiver; extensive trench excavation; scope expansion to address damaged pipe; and additional site restoration work).

End of Line 406 Replacement (Sections 1, 2A, 4 and 5)
and Hydrotest (Section 2) Project Workpaper

EXHIBIT E

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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.	Application 11-11-002 (Filed November 1, 2011)

OPENING BRIEF OF THE UTILITY REFORM NETWORK

ON PIPELINE SAFETY ENHANCEMENT PLAN ISSUES

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October 19, 2012

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SUMMARY OF RECOMMENDATIONS

General Criticisms of Sempra Utilities' Proposal

- The Sempra Utilities' proposed plan is based on preliminary cost estimates from August 2011 that the utilities themselves did not prepare and reflect incomplete analysis of which pipelines will be replaced rather than pressure-tested; for these and other reasons, the Commission cannot find the plan reasonable at this time.

- Under the Sempra Utilities' proposal, there would be no reasonableness review of the recorded costs associated with actual pressure tests or pipeline replacements; instead, the utilities would self-review the reasonableness of their own actions.

- The Commission should adopt intervenor proposals that would permit the Commission to simultaneously begin a subset of pipeline safety programs while ensuring its ability to perform the "comprehensive analysis" called for in D.11-06-017 before approving $1.7 billion of direct costs.

Responsibility for Phase 1 Costs

- None of the testing or replacement costs in the Phase 1 PSEP for post-1955 pipe segments would need to be incurred if the Sempra Utilities had retained the pressure test records for those segments as directed by applicable standards and regulations. Such records are necessary to validate the safe operating pressure of transmission pipelines and therefore critical for public safety. California law requires shareholders to absorb all the costs resulting from the Sempra Utilities' violations of these important pipeline safety laws and standards.

- With respect to the many segments with an indentified manufacturing threat that are slated for work in the PSEP, the Sempra Utilities should be required to demonstrate that any testing that should have been conducted under federal Integrity Management requirements would not obviate the need to address the segment in the PSEP.

Reasonableness of Sempra Utilities' Phase 1A Recommendations

- The Commission should defer action on the Sempra Utilities' proposed decision tree at this time; the ultimate determination of whether to pressure test or replace a line is a key decision for each and every pipeline that is a subject of the plan, yet the decision tree at this time relies on promised-but-not-unveiled criteria that are more in the nature of still-evolving "guidelines that provide direction."

- The Commission should reject the Sempra Utilities' proposal that the review of the PSEP at this stage serve as the likely exclusive opportunity for the agency to address the utilities' decision-making process. The proposed substitutes for actual review of the actual decisions (Engineering Advisory Board, annual reports, expedited advice letters and audits) are inadequate, given the importance of the underlying work, the amount of ratepayer funding that may be at stake, and the poorly-defined nature of these alternative review mechanisms.

- The Commission should deny rate recovery for the vast majority of the costs labeled "interim safety enhancement measures," as they are in fact records search costs that should not be included in rates due to the prohibition against retroactive ratemaking, the connection to past utility imprudence, and a failure to demonstrate the reasonableness of the costs.

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

- For the Valve Enhancement Plan, the Commission should adopt the principle that reliance on automatic shut-off valves (ASVs) is the preferred approach where feasible, and direct CPSD and the utilities to work together to toward the goal of reducing the number of remote controlled valves (RCVs) installed and thereby increasing the potential cost-effectiveness of this element of the Sempra Utilities' PSEP without sacrificing safety.

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

- The Commission should not adopt the Sempra Utilities' proposals for "technology enhancements" due to their failure to present any evidence that the value to customers of the fiber optics and methane detection monitors warrants incurring the cost.

- The Commission should not adopt the Sempra Utilities' proposal for pre-1946 pipeline "mitigation" measures at this time. The utilities have not demonstrated that these construction techniques are jeopardizing the safety of their pipeline systems, yet these measures represent the most expensive single component contained within the Sempra Utilities' Proposed Case.

- For the Enterprise Asset Management System (EAMS), the Commission should authorize the Sempra Utilities to track the related costs in their Pipeline Safety and Reliability Memorandum Accounts, subject to subsequent reasonableness review in the next general rate case or in another proceeding the Commission designates for such review. In addition to cost-effectiveness and other more traditional reasonableness review issues, the Sempra Utilities would need to demonstrate that the EAMS effort is incremental to the effort necessary to meet existing prudent record-keeping standards.

Reasonableness of Cost Estimates

- The record evidence in this proceeding demonstrates that the cost estimates put forward by the Sempra Utilities to date are too rough and too preliminary in nature to permit the Commission to adopt a reasonable revenue requirement in a manner consistent with its Constitutional and statutory duties.

- Even the best "Class 5 or slightly better" cost estimates are still too preliminary and conceptual to be the basis for adopting a revenue requirement forecast without subsequent reasonableness review of the actual costs.

- The Sempra Utilities' broad application of contingency amounts of 20-30% highlight the preliminary nature of their estimates and, by extension, the inappropriateness of using those estimates to establish cost recovery for ratemaking purposes.

- The Commission should address generic forecasting issues applicable to future PSEP cost estimates: The AFUDC rate should be set at a level consistent with short-term debt costs; and the incentive compensation loader should be removed.

Alternatives to Replacement or Pressure Testing

- The Commission should include in its future review of proposed PSEP projects an assessment of the then-current state of technology and adopt cost forecasts that reflect the actual available options.

Revenue Requirements

- The Commission should reject the proposal for a separate PSEP-specific attrition mechanism.

Ratemaking Treatment For Recovery Of Phase 1a Costs

- The Commission should limit any authorized revenue requirement at this time to amounts associated with pressure-testing projects the Sempra Utilities have identified for commencement during the first year of work once the PSEP is approved, with the actual spending subject to after-the-fact reasonableness review.

- The Commission should reject the utilities' proposal for a two-way balancing account in favor of a ratemaking mechanism that creates an opportunity for rate recovery of reasonable costs associated with reasonable projects.

Phase 2

- The Commission lacks a sufficient record to determine whether the Sempra Utilities in Phase 2 should be required to test or replace pipeline segments for which the utility <u>does</u> retain pressure test records meeting the standards of the time the pipe was installed. Half or more of the Sempra Utilities' pipeline miles fall in this category, and the Sempra Utilities have no idea how much testing or replacement of such segments would cost. Before deciding this issue, the Commission should develop a full record regarding the need for and cost of testing or replacing such segments, perhaps in R.11-02-019.

**OPENING BRIEF OF THE UTILITY REFORM NETWORK
ON PIPELINE SAFETY ENHANCEMENT PLAN ISSUES**

The Utility Reform Network (TURN) submits this opening brief addressing issues associated with the Pipeline Safety Enhancement Plan (PSEP) that Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (referred to collectively as "Sempra Utilities") have presented for the Commission's consideration.

For the reasons discussed herein, TURN urges the Commission to deny the Sempra Utilities' requested relief in most regards. Instead, TURN proposes an alternative approach that would balance the need to move forward with pipeline safety-related activities while ensuring the meaningful regulatory review of proposed programs with a $1.7 billion price tag. Furthermore, TURN urges the Commission to ensure that the Sempra Utilities do not recover in rates any costs resulting from their inability to validate safe operating pressures for pipeline installed from 1955 to the present.

I. INTRODUCTION

The Sempra Utilities' PSEP proposal puts the Commission in a difficult position. In D.11-06-017, the agency made clear its expectation that the utilities would move forward with the development and presentation of a plan "to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested."[1] But the plan the utilities have presented here relies on data and analysis that they themselves describe as "preliminary" and "based on minimal engineering, operational planning, and project execution planning."[2] Based on these "preliminary" figures, the Sempra Utilities seek authorization to spend approximately $1.5

[1] D.11-06-017, p. 1.

[2] Ex. SCG-9 (Rivera Direct Testimony), p. 103.

billion in direct costs for SoCalGas and $240 million in direct costs for SDG&E,[3] with a two-way balancing account to assure rate recovery should the recorded costs exceed these preliminary forecasts.[4] And under their proposal, the present review would likely serve as the sole meaningful Commission review of the reasonableness of not only the plan as a proposal based on preliminary data, but also of the actual projects that eventually result from the implementation of the plan, and the costs of those projects.

Fortunately, the other active parties in the proceeding have presented and supported a number of alternative proposals that can and should be adopted in order to develop a more reasonable approach to meeting the Commission's goal set forth in D.11-06-017. For example, the Commission can authorize the utilities to go forward with the projects the utilities had already identified for pressure testing during the first year under the PSEP, but with the associated costs subject to after-the-fact reasonableness review.[5] The Commission can also adopt an expedited application docket process for consideration and review of the proposed pipeline replacement projects, but with the review taking place after the Sempra Utilities had completed the engineering, operational planning and project execution planning necessary to present an actual recommended project and the associated cost forecasts.[6] Such steps would provide the utilities with the guidance and regulatory certainty they seek, but without having the Commission's sole review of this important and expensive years-long effort limited to the current record, before the utilities have

[3] Ex. SCG-1 (Morrow Direct), p. 8.

[4] Ex. SCG-26 (Reyes Rebuttal), p. 2.

[5] Ex. TURN-01 (Long Testimony), pp. 11-12.

[6] Ex. SCGC-01 (Yap Testimony), pp. 10-12.

performed the analysis necessary to know which pipeline segments they actually intend to replace and which ones they plan to pressure test.

Finally, as the Commission considers these proposals, it needs to keep in mind that the burdens of production and proof are squarely on the utilities, not intervenors:

> [The utility] has the burden of affirmatively establishing the reasonableness of all aspects of its application. Other parties do not have the burden of proving the unreasonableness of [the utility's] showing. As the applicant in this rate case, [the utility] has the burden of proving that each of its proposals is reasonable.[7]

II. BACKGROUND AND CONTEXT – THE INTERVENORS' GENERAL APPROACH VERSUS THE SEMPRA UTILITIES' APPROACH.[8]

In D.11-06-017, the Commission provided important guidance about its expectations regarding the contents of the proposed implementation plans called for in that decision, and the review process for those plans:

> We understand that the issues at hand implicate substantial expenses and capital investments, and that the optimum means to address these safety issues may be subject to reasonable debate. To perform our Constitutional and statutory duties, we must have forthright and timely explanations of the issues, as well as <u>comprehensive analysis of the advantages and disadvantages of potential actions</u>.[9]

TURN submits that the Commission should find the Sempra Utilities' proposed PSEP cannot be adopted at this time because many of its most fundamental elements are so preliminary at this time that it makes it impossible to conduct a "comprehensive analysis of the advantages and disadvantages" of the plan. Instead, the agency should adopt a

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[7] D.09-03-025 (SCE 2009 GRC), p. 8 (citing Public Utilities Code Sections 451 and 454; *see also* D.06-05-016 (SCE Test Year 2006 GRC), p. 7).

[8] Late in the brief preparation process TURN realized that the Common Briefing Outline did not include a section that was a neat fit for a broad comparison of the Sempra Utilities' PSEP with the alternative recommendations that intervenors put forward in the proceeding. Therefore TURN has selected the "Background" section as the most appropriate section for such a presentation.

[9] D.11-06-017, p. 17 [emphasis added].

modified approach that combines various of the intervenor recommendations and permits the utilities to begin to go forward with implementation of some initial elements of the PSEP and with the further engineering and planning efforts necessary to support the "comprehensive analysis" the Commission had in mind.

A. The Sempra Utilities' Proposed Plan Contains Numerous Elements That Are Contrary To The Commission-Identified Need For "Comprehensive Analysis" That Might Support A Finding of Reasonableness For The Estimated $1.7 Billion Of Direct Costs.

TURN submits that there are a number of reasons why the Commission should decide that it does not have information of sufficient quantity or quality at this time to support the "comprehensive analysis" called for in D.11-06-017.

1. "Cost estimates are preliminary and were developed based on minimal engineering, operational planning, and project execution planning."[10]

The majority of the costs associated with the Sempra Utilities plan are associated with either pressure testing or replacement of pipeline segments. In describing the "methodology and assumptions … used to prepare the cost estimates for performing pressure testing of existing pipelines," the Sempra Utilities explained that each estimate "is based on preliminary engineering only and includes several assumptions. As a result, the estimate includes a 20% or 30% contingency depending on total estimated cost. <u>Once detailed engineering and design are completed a revised estimate can be generated to reflect the actual scope of project and associated permit conditions</u>."[11] Similar language appeared in the description of the "methodology and assumptions [] used to prepare cost

[10] Ex. SCG-9 (Rivera Direct Testimony), p. 103.

[11] *Id.*, Appendix D ("Pressure Testing Cost Estimating Methodology and Assumptions"), p. D-3 [emphasis added].

estimates for pipeline replacements." And again, the utilities explained that the "estimate is based on preliminary engineering only and includes several assumptions."[12]

2. The cost estimates have not been updated since the PSEP was submitted in August 2011.

When the Sempra Utilities describe their estimates as representing the "best available cost projections," they mean the best available as of August 2011, when they filed the PSEP with the Commission.[13] The utilities "have not undertaken any additional engineering or design that would be required to further define the scope to update the cost estimates."[14]

3. The cost estimates are understated.

The estimates of pipeline replacement costs do not include the costs associated with certain items ("contaminated soilhandling/disposal, asbestos abatement, right-of-way acquisition, construction permits, and environmental permits").[15] Many if not most of the replacement projects are likely to incur costs in at least some of the identified categories. And for each such project, the current estimate for these costs is effectively zero.

Similarly, the cost estimates for pipeline replacement projects and pressure testing projects reflect labor rates as of 2011 and do not include escalation.[16] Since the work under the PSEP will begin in earnest in 2013 and continue for some number of years

[12] *Id.*, Appendix E ("Pipeline Replacement Estimate Assumptions"), p. E-3.

[13] Ex. SCG-21 (Buczkowski Rebuttal), p. 1; Buczkowski, Sempra Utilities, 5 RT 855, ll. 6-12.

[14] Buczkowski, 3 RT 567, ll. 18-21.

[15] Ex. SCG-9 (Rivera Direct Testimony), Appendix E, p. E-2 (item 7a).

[16] *Id.*, Appendix D, p. D-2 (item 12) and Appendix E, p. E-2 (item 7c).

thereafter, the escalation of labor rates during this period will drive costs up for all projects.

4. The cost estimates for pipeline replacement and pressure-testing were prepared by a contractor, not the utilities, and reflect information from the contractor's data base, rather than any Sempra-specific estimates.

The 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.[17] According to SPEC Services, these estimates were intended to provide an understanding of "a rough-order of magnitude (ROM) cost before proceeding." Such estimates "are typically generated without performing any preliminary engineering and rarely include a site visit or a complete understanding of project permitting requirements."[18]

5. The Sempra Utilities have not completed the analysis for any pipeline to determine which segments of pipe should be tested and which should be replaced other than what's set forth in the PSEP filing.

The determination of whether a pipeline segment should be pressure-tested or replaced is one of the most significant factors influencing the costs associated with that pipeline segment. While the Sempra Utilities' rebuttal testimony includes a modified "decision tree" for purposes of understanding how the utilities propose to make that determination, it is at this point a theoretical construct.

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[17] Buczkowski, Sempra Utilities, 5 RT 868, ll. 1-7 and 869, ll. 1-8.

[18] Ex. DRA-32 (Response to DRA-DAO-01-5).

> None of the analyses currently initiated have yet been completed to determine which segments of pipe should be tested and which segments should be replaced beyond what was included in our PSEP filing.[19]

The modified version of the "decision tree" has not yet been used to evaluate specific pipelines proposed for replacement in the Amended PSEP filing.[20] To the extent the utilities claim to have identified pipeline segments that purportedly cannot accommodate pressure testing, that determination "was determined based on assumptions and high level judgments." The verification of those assumptions and high level determinations is expected to be part of the engineering, design, and execution planning activities for each project.[21]

6. There would be no formal reasonableness review of the recorded costs associated with actual pressure tests or pipeline replacements; instead, the Sempra Utilities would self-review the reasonableness of their actions.

The Sempra Utilities' proposal does not include any formal Commission review of its forecasted or recorded PSEP-related costs other than the review that occurs in this proceeding.

> As long as costs incurred within the PSEP have been approved by the Commission, there should be no need for after-the-fact reasonableness review of the costs recorded in the PSEP Cost Recovery Accounts or for expedited applications for pipeline replacement projects. <u>SoCalGas and SDG&E will review PSEP costs that are recorded in their PSEP Cost Recovery Accounts</u> to ensure that these costs are truly incremental and not otherwise recovered in base transportation rates or subject to any other Commission-approved balancing account mechanism.[22]

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[19] Ex. DRA-30, DR DAO-36-3.

[20] *Id.*, DR DAP-36-4.

[21] Ex. DRA-31, (DR DBP-4-1).

[22] Ex. SCG-26 (Reyes Rebuttal), p. 6 [emphasis added].

Other than the expedited advice letter the utilities propose for seeking additional funding authorization if their spending exceeds the amount authorized here, there appears to be no condition under which the utilities would need to get approval for anything proposed as part of Phase 1A.[23]

7. The Sempra Utilities have not yet completed detailed customer impact analyses for any project.

"Customer impacts" is a central criterion for the Sempra Utilities' proposed approach to deciding whether to replace or pressure test a pipeline segment. But at this juncture, "No studies have yet been done on the impacts to customers. This will occur as each pipeline is reviewed in greater detail during the design and engineering phase."[24]

8. The proposed Engineering Advisory Board has not been discussed with its putative members, and seems to have been barely discussed within Sempra Utilities before it was included in the utilities' rebuttal testimony.

The Sempra Utilities proposed an Engineering Advisory Board to "provide the Commission staff with transparency to the decision process."[25] The Board proposal is the product of approximately fifteen minutes of internal utility discussions that did not result in any written documentation.[26] The utilities have not discussed even the concept of such a board with the Consumer Protection and Safety Division (CPSD) or Energy Division, each of which would have a member on the board as conceived of by the utilities.[27]

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[23] Buczkowski, Sempra Utilities, 5 RT 860, ll. 5-15.

[24] Ex. DRA-30 (DR DAO-36-2). *See also* Ex. DRA-30, DR DBP-4-20 ("Detailed customer impact analyses have not been completed for any project at this time. This type of analysis will be completed as part of the engineering, design, and execution planning activities for each project.")

[25] Ex. SCG-13 (Morrow Rebuttal), pp. 12-13.

[26] Ex. TURN-22 (DR TURN-7-2(a)).

[27] Ex. DRA-31 (DR DBP-4-5).

9. The plan for strong controls and transparency that the utilities believe should mollify many of the concerns regarding the decision-making process is not yet before the Commission, and would itself never be subject to Commission review.

The Sempra Utilities describe an ongoing effort to "establish a comprehensive control environment" for the PSEP and the associated projects.[28] The results of this effort, in the form of an actual plan to achieve such strong controls and transparent decision-making, is intended to be on a parallel track with this proceeding. That is, it would continue to be developed as the Commission prepares, considers and approves a decision on the PSEP proposal. That plan is <u>not</u> something the utilities have presented as yet to the Commission, nor do they ever intend to have the Commission review or approve the plan.[29]

B. The Intervenors' Proposals Would Permit The Commission To Simultaneously Begin A Subset Of Pipeline Safety Programs While Ensuring Its Ability To Perform The "Comprehensive Analysis" Called For In D.11-06-017 Before Approving $1.7 Billion of Direct Costs.

The Commission's efforts to develop and implement a reasonable pipeline safety plan for the Sempra Utilities is aided by the fact that a variety of intervenors presented a number of alternative proposals for moving forward. By combining a number of these proposals into the decision adopted at this time, the Commission can simultaneously permit concrete initial steps consistent with the Sempra Utilities' plan and require the further development of that plan necessary to perform the comprehensive analysis called for in D.11-06-017.

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[28] Ex. SCG-21 (Buczkowski Rebuttal), p. 16.

[29] Buczkowski, Sempra Utilities, 6 RT 1051, l. 27 to 1052, l. 21.

TURN has identified two key components of what could be approved at this time. As noted earlier, the Commission should authorize the utilities to go forward with the projects the utilities had already identified for pressure testing during the first year under the PSEP, but with the associated costs subject to after-the-fact reasonableness review.[30] The Commission can also adopt an expedited application docket process that would serve as the forum for consideration and review of the proposed pipeline replacement projects, but with the review taking place after the Sempra Utilities had completed the engineering, operational planning and project execution planning necessary to present an actual recommended project and the associated cost forecasts.[31]

There are numerous advantages to this alternative approach. As the Sempra Utilities acknowledged, once they have performed the actual analysis and engineering required to go forward with either pressure testing or pipeline replacement for "the first dozen," they should have a better understanding of the factors that need to be considered in determining whether to pressure test or replace a particular pipeline segment.[32] It would also give the Commission a better sense of the accuracy of the preliminary cost estimates the utilities have put forward here, since it would permit comparison of those estimates to the actual costs recorded for actual projects. And the alternative approach would permit the Commission to assess the product of the utilities' current efforts to develop a more concrete and comprehensive proposal for the governance structure and control environment that they intend to use for the PSEP activities. At this stage the utilities are

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[30] Ex. TURN-01 (Long Testimony), pp. 11-12.

[31] Ex. SCGC-01 (Yap Testimony), pp. 10-12. There were other elements of the various intervenors' showings that may warrant approval at this time as well; TURN's recommendations focus on the two that would mitigate the most significant shortcomings of the Sempra Utilities' plan.

[32] Phillips, Sempra Utilities, 6 RT 1101, ll. 6-9.

still working on the proposal for such a plan, and hope to have the proposal within a couple of months,[33] with the plan itself presumably following at some point later.[34]

The Commission should look askance at the criticisms the Sempra Utilities raised in response to these intervenor proposals. In particular, the Commission must reject the utilities' attempt to affix a "wait and see" label to such proposals, as if intervenors are asking the Commission to forestall any action on the PSEP at this time.[35] The intervenor proposals would permit immediate action, albeit within reasonable constraints and subject to reasonableness review. The only "wait" under those proposals is for the Sempra Utilities to complete the engineering and planning necessary to support actual proposals for actual projects. Given the utilities' own labels of "preliminary" and "rough estimates" for the support for the proposals as they stand today, such a "wait" is only prudent. And the Commission should keep in mind that the Sempra Utilities have been engaged in their own "wait and see" approach over the past year since submitting their PSEP proposal, an approach that will continue until the Commission issues its decision.[36]

Similarly, the Commission should ignore claims that a process based on the expedited application process used in the past would be "unnecessary, bureaucratic and cumbersome"[37] when the claims are based on ignorance of the expedited application process, including the reliance on a master data request, or the time frame for Commission

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[33] Buczkowski, Sempra Utilities, 5 RT 1046, ll. 8-18.

[34] The Sempra Utilities have not presented the proposal or plan for governance structure or control environment in this proceeding, and under their PSEP proposal do not intend the Commission to ever review or approve that plan. *Id.*, at 1052, ll. 9-21.

[35] Ex. SCG-21 (Buczkowski Rebuttal), p. 2.

[36] With the exception of the priority projects identified in Attachment A to their January 13, 2012 filing, the Sempra Utilities will not begin actual work to implement the PSEP until the Commission issues its decision in this proceeding. Buczkowski, 6 RT 1051, ll. 11-18.

[37] Ex. SCG-20 (Phillips Rebuttal), p. 16.

action on such an application.[38] The assumption that this review would slow down the implementation process is premised in large part on the fact that the Sempra Utilities would have to get the project-specific engineering work done first, before obtaining approval for the project.[39] TURN submits that deferring the review until after the engineering work is completed does not necessarily slow down the review process; rather, it simply requires that the review take place later in the process. And the fact that it takes place after the engineering is completed is an attribute if the goal is to assess the reasonableness of the proposed project.

III. RESPONSIBILITY FOR PHASE I COSTS: The Sempra Utilities Should Not Be Permitted to Impose on Ratepayers Costs Resulting from Their Failure to Comply with Post -1955 Industry Standards and Regulations Requiring Documentation to Validate Safe Operating Pressure

All of the work proposed in Phase 1A of the Sempra Utilities' PSEP results from absent documentation of a pressure test to at least 1.25 times maximum allowable operating pressure ("MAOP").[40] Such records are essential to validate the safe operating pressure of a pipeline. As we tragically learned from the San Bruno explosion, a pipeline is only as strong as its weakest pipe segment. Consequently, accurate and reliable pressure test records are needed for each segment.[41] Many of the pipe segments that lack documentation of a pressure test were installed from 1955 to the present, a period during which the industry standards (from 1955 to 1960) and then regulations (from 1961 to the

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[38] Phillips, Sempra Utilities, 7 RT 1190, ll. 6-21.

[39] *Id.*, at 1191, ll. 11-15.

[40] Ex. TURN-1 (Long Test.), p. 15.

[41] The "weakest element" concept has long been embodied in industry standards for establishing MAOP. *See, e.g.,* Ex. TURN-9 (General Order 112), Section 845.22(a) (design pressure, one of two calculations needed to set MAOP, must be determined for the weakest element of the pipeline). As discussed below, GO 112 incorporated industry standards from 1955.

present) required pipeline operators to conduct a post-installation pressure test and to retain records of such a test <u>for the life of the pipeline</u>. The inability to document safe operating pressure for each pipe segment has unacceptably increased the risk to public safety, necessitating the Commission's order in Decision (D.) 11-06-017 to pressure test or replace all transmission segments for which utilities lack pressure test records.

Under California statutes and well-established principles of California public utilities law, the Sempra Utilities may not impose costs on ratepayers that result from their failure to comply with industry standards and regulations. None of the costs in the Phase 1 PSEP for post-1955 pipe segments would need to be incurred if the Sempra Utilities had shown sufficient regard for safety and retained the pressure test records for those segments as directed by applicable standards and regulations. Accordingly, California law requires shareholders to absorb <u>all</u> the costs resulting from the Sempra Utilities' violations of these important pipeline safety laws and standards.

A. Applicable Standards and Burden of Proof

1. Costs Resulting from the Sempra Utilities' Imprudence May Not Be Recovered from Ratepayers

As the applicants seeking to increase rates to pay for the costs of their PSEP, the Sempra Utilities bear the burden of proving that their proposed costs are just and reasonable, in accordance with Public Utilities Code Section 451.[42] It is well settled that costs that result from a utility's imprudence are not reasonable under Section 451 and may not be recovered from ratepayers.[43] As the Commission emphatically stated in D.84-09-

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[42] *See generally* Decision (D.) 09-03-025, slip. op., p. 8 and decisions cited therein. Statutory citations are to the California Public Utilities Code unless otherwise indicated.

[43] *See, e.g.*, D.94-03-048, 53 CPUC 2d 452, 456 (holding that it is not reasonable to pass on to Southern California Edison ratepayers costs resulting from the Mojave Coal Plant accident); D.85-

120, "it would be unconscionable from a regulatory perspective to reward such imprudent activity by passing the resultant costs through to ratepayers."[44]

Even the Sempra Utilities acknowledge that operations and maintenance ("O&M") and capital costs that are unreasonable or imprudent are an exception to the general rule that such costs are borne by ratepayers.[45]

2. As Operators of Pipelines Carrying Combustible Gas, the Sempra Utilities Must Be Held to a High Standard of Prudence

The Commission's prudence standard relies on the concepts of reasonable judgment and good utility practices:

> The term 'reasonable and prudent' means that at a particular time any of the practices, methods and acts engaged in by a utility follows the exercise of <u>reasonable judgment</u> in light of the facts known or which should have been known at the time the decision was made. The act or decision is expected by the utility to accomplish the desired result at the lowest reasonable cost <u>consistent with good utility practices</u>. Good utility practices are based upon cost effectiveness, safety and expedition.[46]

In applying this standard, the Commission has held that it will expect the utility's managers to exercise "proportionately greater care" to decisions involving large amounts of money, greater levels of uncertainty, or high degrees of risk.[47] Gas pipelines clearly present a high degree of risk to persons and property in that they transport highly

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08-102, 18 CPUC 2d 700, 715-716 (holding that ratepayers are not responsible for bearing the consequences of PG&E's imprudence with respect to the Helms Pumped Storage Project).

[44] 16 CPUC 2d 249, 283.

[45] Ex. SCG-13 (Morrow), p. 6, lines 11-13.

[46] D.94-03-048, 27 CPUC 2d at 464.

[47] *Re San Diego Gas & Electric Co.,* D.89-02-074, 31 CPUC 2d 236, 246. *See also Re Pacific Gas & Electric Co.* (Helms Pumped Storage Project), D.85-08-102, 18 CPUC 2d 700, 710-711 (where tasks undertaken are of such enormity to expose the utilities and potentially ratepayers to substantial financial risks, utilities must exercise "even greater care and managerial acumen" than would be called for in ordinary circumstances; rejecting view that "marginal" or "average" performance was required and holding PG&E to a "good performance" standard).

combustible natural gas.[48] Accordingly, the Sempra Utilities' management of its natural gas pipeline system should be held to a proportionately high standard of prudence.

3. The Sempra Utilities' Failure to Comply with the Accepted ASME Standards is Clear Evidence of Imprudence

Typically, the Commission considers evidence of industry practice as part of its analysis of whether a utility has acted consistent with good practice and exercised reasonable judgment. Industry standards, such as the American Society of Mechanical Engineers ("ASME") B31.8 standards[49] for gas pipeline construction, operation and maintenance, are particularly compelling evidence of industry practice.[50] Indeed, because the Sempra Utilities acknowledge that they voluntarily adhered to the 1955 standards and in fact participated in the development of those 1955 standards,[51] there can be no dispute that those standards are an appropriate yardstick against which to measure the prudence of the Sempra Utilities' behavior.

Needless to say, a violation of applicable law can never be an exercise of reasonable judgment or consistent with good practice and is thus always imprudent. For this reason, Sempra Utilities testimony asserting that it is common within the industry to lose pressure test records is immaterial.[52] As shown below, under GO 112, first

[48] D. 61269, issued Dec. 28, 1960, slip. op., p. 5 ("Gas is a highly combustible and volatile element, possessing explosive characteristics under certain conditions.")

[49] In this brief, the term ASME B31.8 standards refers to the ASME standards for gas transmission and distribution piping systems, first promulgated in 1955 in American Standards Association ("ASA") B31.1.8 and periodically revised thereafter.

[50] D.94-03-048, 53 CPUC 2d at 465 ("A utility faces a greater challenge in establishing the reasonableness of its conduct when it fails to act in a manner consistent with industry practice.")

[51] Ex. TURN-1 (Long Test.), p. 16, citing the Sempra Utilities' response to TURN's data request 5-2.

[52] *See, e.g.,* Ex. SCG-17 (Rosenfeld Rebuttal, Sempra Utilities), p. 29.

promulgated in 1961, and the 1970 federal regulations, operators have been required to retain post-installation pressure test records for the life of the pipeline, and the possibility that other operators may (or may not) have been less than scrupulous in complying with these legal requirements does not change the fact that such legal violations are *per se* imprudent.

4. The Sempra Utilities Have the Burden of Proving that Their PSEP Costs Do Not Result from Their Imprudence

Commission decisions make clear that the utility bears the burden of proof on the issue of prudence and is not entitled to a "presumption of prudence."[53] The utility must carry this burden affirmatively; requests for rate increases that lack sufficient evidence of reasonableness are subject to dismissal.[54]

Contrary to these decisions, the Sempra Utilities have improperly assumed that their PSEP was entitled to a presumption of prudence. Their opening testimony fails even to address the fact that much of their proposed Phase IA work is the result of their imprudent failure to retain pressure test documentation. Notwithstanding 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.

[53] *See., e.g.,* D.85-08-102 ((Helms Pumped Storage Project), 18 CPUC 2d 700, 709-710 (also lamenting that procedure in that case had required Commission staff to "suffer the greatest evidentiary burden," which "handicapped" CPUC's reasonableness review); D. 93-05-013, 49 CPUC 2d 218, 220.

[54] D.86-10-069, 22 CPUC 2d 124, 150 (also noting that procedures in the future should place less reliance on the showings of the CPUC staff and intervenors and more emphasis on utilities' direct showings).

5. Public Utilities Code Section 463 Mandates Disallowance of Costs Resulting from the Sempra Utilities' Unreasonable Inability to Document Required Pressure Tests

In addition to the general prudence requirements of Section 451, Section 463 mandates disallowance of a significant portion of the PSEP costs. Section 463 provides that the Commission "shall disallow" any "direct or indirect" costs resulting from any unreasonable error or omission "relating to" the construction or operation of any portion of a utility's plant costing more than $50 million.[55] The Sempra Utilities' unreasonable errors and omissions – the inability to document pressure tests required by post-1955 industry standards and regulations – not only "relate to" the planned PSEP expenditures (which total several orders of magnitude in excess of $50 million), they cause the need for much of the proposed PSEP costs. Accordingly, Section 463 clearly applies and requires the Commission to disallow all the costs in the PSEP that either directly or indirectly result from those errors and omissions.

6. The Sempra Utilities Confuse Disallowances Under Sections 451 and 463 With Penalties

In their rebuttal testimony, the Sempra Utilities make a concerted effort to characterize as penalties any proposal to disallow PSEP costs.[56] Their witnesses claim that it is improper to use the ratemaking process to impose such "penalties."[57]

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[55] Section 463(a) states in relevant part: "For purposes of establishing rates for any electrical or gas corporation, the commission ***shall** disallow* expenses reflecting the direct or indirect costs resulting from any unreasonable error or omission relating to the planning, construction or operation of any portion of the corporation's plant which cost, or is estimated to have cost, more than fifty million dollars ($50,000,000), including any expenses resulting from delays caused by any unreasonable error or omission. Nothing in this section prohibits a finding by the commission of other unreasonable or imprudent expenses." (Emphasis added).

[56] *See, e.g.,* Ex. SCG-13 (Morrow Rebuttal) in which Mr. Morrow characterized ratepayer representative proposals for disallowances as penalties 11 times in his 13-page testimony. Tr., vol. 1, p. 55, lines 3-11 (Morrow, Sempra Utilities).

In so contending, the Sempra Utilities ignore the basic principles of California public utilities law that are discussed above. As explained, disallowances are an important ratemaking tool to prevent utilities from passing on to their customers costs that result from utility imprudence. Without disallowances for imprudence, regulators would lack a key vehicle for ensuring that utilities experience the kind of discipline that is lacking for a monopoly service. Moreover, disallowances are a way to ensure fairness in utility rates as between ratepayers and shareholders, an obvious goal enshrined in Section 451's "just and reasonable" requirement. 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.

In their attempt to blur the clear distinction between ratemaking disallowances and penalties, the Sempra Utilities unsuccessfully attempt to impose an unduly high burden on ratepayer representatives.[58] However, as shown, it is the Sempra Utilities who bear the burden of showing that the costs they seek to impose on ratepayers are not the result of their imprudence. Furthermore, contrary to the Sempra Utilities' claim, such imprudence does not require a showing that the deficient utility behavior was deliberate. As demonstrated above, to encourage the just and reasonable services required by Section 451, disallowances are appropriate whenever utility costs result from unreasonable judgment or less than good practices, intentional or not.

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[57] *See, e.g.,* Ex. SCG-13 (Morrow Rebuttal), pp. 5-6.

[58] See, e.g., Ex. SCG-13 (Morrow), p. 9 ("Shareholder penalties are properly assessed when there is a showing that the conduct is the result of a serious failure of utility management amounting to deliberate disregard of clear regulatory direction or performance consistently and demonstrably below industry norms.")

Moreover, the Sempra Utilities' suggestion that disallowance recommendations are a "breach of the regulatory compact"[59] directly conflicts with the Scoping Memo for this phase of the case. The Scoping Memo specifically identifies as an issue whether some of the PSEP costs should be disallowed and borne by shareholders:

> 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.[60]

Thus, far from breaching the regulatory compact, the proposals of TURN and the other ratepayer representatives to disallow recovery of costs are fully consistent with basic principles of public utilities regulation and the prescribed scope of this case. In the words of the Scoping Memo, it is not reasonable for ratepayers to pay to remedy the neglect and failure of the Sempra Utilities to properly document the post-1955 pressure tests that are an important means to validate MAOP.

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

1. As Long as the Sempra Utilities Have Operated Pipelines, Section 451 Has Required Them to Proactively Ensure the Retention of Accurate and Accessible Records to Validate Safe Operating Pressures

As long as the Sempra Utilities have operated gas transmission pipelines in California, Section 451 and its predecessors have required each public utility in California to "furnish and maintain such adequate, efficient, just and reasonable service,

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[59] Ex. SCG-13 (Morrow), p. 5.

[60] *Assigned Commissioner's Scoping Memo and Ruling*, February 24, 2012, p. 5 (emphasis added).

instrumentalities, equipment, and facilities, . . . as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." When the Commission adopted GO 112 in 1960, it made clear that utilities shouldered important, preexisting safety obligations under Section 451 that were unaffected by the new rules:

> . . . the promulgation of precautionary safety rules does not <u>remove</u> or minimize <u>the primary obligation and responsibility</u> of respondents [California gas utilities] to provide safe service and facilities in their gas operations. Officers and employees of the respondents must <u>continue to be</u> ever conscious of the importance of safe operating practices and facilities and of their obligation to the public in that respect.[61]

In addition, GO 112 expressly stated that compliance with the GO 112 rules "is not intended to relieve a utility of any statutory requirements."[62]

Thus, before any specific state or federal pipeline safety regulations were adopted, Section 451 imposed a proactive duty on utilities to do all things necessary to promote safe operation of their pipelines. This duty continues to this day and is not limited by any specific provisions in GO 112 or federal regulations. Moreover, as further discussed below, federal regulations establish only minimum requirements that states are free to surpass in provisions such as Section 451.

Given the highly combustible nature of natural gas, operating pipelines at safe pressures is obviously part and parcel of Section 451's requirement to operate safe facilities. To fulfill this duty, utilities must retain accessible records showing the MAOP for each pipeline segment and any pressure tests or other underlying records on which the MAOP is based. Such records are particularly important because of the long operating lives of pipelines. As the Sempra Utilities' system shows, it is not unusual for pipelines to

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[61] D. 61629 (Dec. 28, 1960), Finding No. 8, slip. op., p. 12 (emphasis added).

[62] Ex. TURN-9 (GO 112), Section 104.4.

remain in use for 60 years or more.[63] Without careful MAOP documentation, years after a pipeline's installation, utilities cannot demonstrate either to themselves or to their regulators that MAOP was properly established. Thus, even if GO 112 and federal regulations had never been adopted, Section 451 has always required the Sempra Utilities to retain accessible records to validate MAOP for each pipeline segment, as an integral part of the requirement to ensure safe operating pressure.

2. Under the ASME B31.8 Standards In Effect from 1955 through 1960, Accepted Industry Practice Was to Pressure Test Pipe Segments After Installation and to Retain Records of Those Tests For the Life of the Pipeline

By at least 1955, with ASME's adoption of ASA B31.1.8, it became accepted industry practice for transmission pipeline operators to pressure test any pipeline segment after installation and prior to service and to retain records of those tests for the life of the pipeline.[64] The Sempra Utilities do not dispute that the 1955 ASME standards were generally accepted in the industry and established necessary practices for safety.[65] In fact, as noted above, the Sempra Utilities acknowledge that they adhered to these standards.[66]

Section 841.411 of those 1955 standards stated that all pipelines to be operated at a hoop stress of 30% or more of the pipe's specified minimum yield strength ("SMYS") "shall" be given a post-construction, pre-service field test "to prove strength." The test

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[63] *See* Ex. SCG-34-R (Mileage Table requested by ALJ), showing in the "Total Existing Transmission Miles" column that 1,160 of the total 3,885 system miles were installed prior to 1955.

[64] TURN is not taking a position on whether this was prudent industry practice prior to 1955.

[65] Ex. SCG-17 (Rosenfeld, Sempra Utilities), p. 8; Tr., vol. 2, p. 224, lines 2-24, Rosenfeld, Sempra Utilities.

[66] Ex. TURN-1 (Long Testimony), p. 16, citing the Sempra Utilities' response to TURN's data request 5-2.

pressure varied with Class Location: 1.1 times MAOP for Class 1; 1.25 times MAOP for Class 2; and 1.4 time MAOP for Class 4.[67]

In addition, the 1955 ASME standards explicitly required operators to retain a record of the pressure test for the life of the pipeline:

> 841.417 Records. The operating company shall maintain in its file for the useful life of each pipeline and main, records showing the type of fluid used for test and the test pressure. (Emphasis added.)

Thus, there can be no dispute that it was accepted industry practice beginning in 1955 to retain for the life of the pipeline a pressure test record showing the type of fluid used for the test (e.g., water or gas) and the test pressure.[68]

These pressure test and record-keeping requirements remained unchanged in the 1958 version of ASA B31.8 and thus were in place up until the adoption of GO 112 in 1961.[69]

The 1955 ASME standards make clear that post-installation pressure tests were an integral part of the process of establishing MAOP for a pipeline. Under Section 845.22, MAOP was to be the lower of two pressures: (1) the design pressure of the weakest element of the pipeline, calculated using pipeline specification data in accordance with Section 841.1; and (2) the pressure obtained by dividing the post-construction test pressure by the appropriate class location factor (1.1 for Class 1, 1.25 for Class 2, and 1.4 for Classes 3 and 4). Thus, the pressure test results were necessary to determine the safe

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[67] ASA B31.1.8-1955, Section 841.412.

[68] In rebuttal, witness Morrow, relying on witness Rosenfeld, claimed that the 1955 standards included "many permissible exceptions" to testing and record-keeping requirements. (Ex. SCG-13, Morrow, Sempra Utilities, p. 8). However, in the hearings, Mr. Rosenfeld conceded that the supposed exceptions cited in his testimony still required a pressure test of some sort and still required retaining a record of such test. Tr., vol. 2, p. 232, line 22 – p. 235, line 12 (Rosenfeld, Sempra Utilities).

[69] Ex. SCG-17 (Rosenfeld, Sempra Utilities), pp. 15, 21.

operating pressure of the pipeline. Of particular significance to this case, in the event that a question arose at some point regarding whether the MAOP had been properly determined, the pressure test records required by Section 841.417 were important documentation for both the operator and the regulator.

In rebuttal testimony, the Sempra Utilities note that the ASME standards are not, in and of themselves, regulations.[70] However, this point is irrelevant to the cost responsibility issue presented in this case. The issue here is prudence, not (as would be the case in a true penalty proceeding) whether laws have been violated. As explained above, the Sempra Utilities' failure to comply with the industry-accepted 1955 standards was and is both unreasonable judgment and less than good practice -- and therefore clearly imprudent. In any event, this failure constitutes a violation of Section 451, which, as noted above, has always required the Sempra Utilities to proactively take the necessary steps to ensure safe pipeline operation. At a minimum, Section 451 has always required utilities to meet the accepted standards of the day for testing and documenting safe operating pressure.

3. General Order 112, In Effect from 1961 to 1970, Required Operators to Pressure Test Pipe Segments After Installation and to Retain Records of Those Tests For the Life of the Pipeline

With the adoption of General Order 112 in 1961, the Commission adopted "minimum requirements" for the design, construction, testing, operation and maintenance of transmission and distribution facilities "to safeguard life or limb, health, property and public welfare . . .."[71] GO 112 incorporated the pressure test and record-keeping requirements of the ASA B31.8-1958 standards discussed above, while imposing some

[70] *See, e.g.*, Ex. SCG-17 (Rosenfeld, Sempra Utilities), p. 8.

[71] Ex. TURN-9 (GO 112), Section 102.1.

stricter requirements, including: (1) extending the pressure test requirements to pipe operating at hoop stresses of 20% SMYS (rather than 30% SMYS) or more;[72] (2) increasing the pressure test margins to 1.25 for Class 1, and 1.5 for Class 3 and 4 pipe;[73] and (3) requiring the test pressure to be maintained until it was stabilized and for a period of not less than 1 hour.[74]

GO 112 also adopted, unchanged, Section 845.22 of the ASA standards (described above) requiring MAOP to be based on the lower of design pressure and the prescribed pressure test calculation.[75]

With respect to record-keeping, GO 112 adopted, without change, the pressure test record-keeping requirement of Section 841.417 of ASA B.31.1.8 quoted above, including the requirement to retain such records "for the useful life" of each pipeline.[76]

To further underscore the importance of careful record-keeping, GO 112 added to the ASME standards an entire chapter, Chapter VI, devoted to records. The provisions in that chapter required:

> 301 GENERAL
>
> 301.1 The responsibility for the maintenance of necessary records to establish that compliance with these rules has been accomplished rests with the utility. *Such records shall be available for inspection at all times by the Commission or the Commission staff*.
>
> 302 SPECIFICATIONS

[72] Ex. TURN-9 (GO 112), p 38 (Section 209.1, modifying B31.8 section 841.411); Ex. SCG-17 (Rosenfeld, Sempra Utilities), p. 17.

[73] Ex. TURN-9 (GO 112), p 38 (Sections 209.11 and 209.12, modifying B31.8 sections 841.412); Ex. SCG-17 (Rosenfeld, Sempra Utilities), p. 17.

[74] Ex. TURN-9 (GO 112), p. 39 (Section 209.14); Ex. SCG-17 (Rosenfeld, Sempra Utilities), p. 17.

[75] Ex. TURN-9 (GO 112), p. 47.

[76] Ex. TURN-9 (GO 112), p. 39.

> 302.1 Specifications for material and equipment, installation, *testing* and fabrication shall be maintained by the utility.
>
> 303 OPERATING AND MAINTENANCE PROCEDURES
>
> 303.1 Plans covering operating and maintenance procedures, *including maximum actual operating pressure to which the line is intended to be subjected*, shall be maintained by the utility.
>
> 303.2 No pipeline shall be operated in excess of the maximum actual operating pressure recorded by the company in accordance with this section.[77]

These provisions are highly relevant to the cost responsibility issue in at least two respects. First Section 301.1 shows that the Commission considered record-keeping to be important not just to serve *the utility's* operational needs, but also to enable *the Commission* to audit and verify that operators had complied with the requirements of GO 112, including the requirement to conduct pre-service pressure tests. Second, the emphasis in Sections 302.1, 303.1 and 303.2 on records for testing and MAOP demonstrates the importance of scrupulous record-keeping to demonstrate that pipelines are properly tested and operated at safe operating pressures.

Modifications to GO 112 in 1964 and 1967 did not change the provisions related to pressure tests and record-keeping.[78]

4. Beginning in 1970, Federal Regulations, Adopted by GO 112, Continued to Require Operators to Pressure Test Pipe Segments After Installation and to Retain Records of Those Tests For the Life of the Pipeline

In 1970, federal pipeline safety regulations went into effect for the first time. The federal regulations were, and are, explicit, that they establish only "minimum"

[77] Ex. TURN-9 (GO 112), p. 61 (emphasis added).

[78] Ex. SCG-17 (Rosenfeld, Sempra Utilities), p. 17, 23.

requirements,[79] allowing state regulations to add stricter requirements. Consequently, any and all additional obligations imposed by Section 451 and GO 112 also must be considered to establish the full scope of regulations applicable to the Sempra Utilities in the post-1970 period.

Subpart J of the federal regulations required (and continues to require) post-installation, pre-service pressure tests "to substantiate the proposed maximum allowable operating pressure."[80] For pipelines to operate at a hoop stress of 30% SMYS or greater, Section 192.505 specified the pressure test requirements, including requiring a minimum eight hour duration for the test.[81] Section 192.517 required operators to make and retain for the useful life of the pipeline a record of these pressure tests to include seven elements: (1) name of operator and testing company; (2) test medium; (3) test pressure; (4) test duration; (5) pressure recording charts; (6) elevation variations; and (7) leaks and failures noted and their disposition.[82] These provisions in the original 1970 regulations have not changed substantively in the current regulations.

In 1971, the Commission adopted GO 112-C, which replaced content from the B31.8 standards that had formed the foundation of the earlier versions of GO 112 with the new federal regulations in 49 C.F.R., Part 192, along with some additional requirements that exceeded the minimum requirements of federal law.[83] Those additional requirements included the same record-keeping requirements that had been contained in Sections 301.1, 302.1, and 303.1 in GO 112. Thus, Section 121.1 of GO 112-C (identical to the former

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[79] 49 C.F.R. Section 192.1(a).

[80] Ex. SCG-30 (1970 regulations), 49 C.F.R. Section 192.503(a)(1).

[81] *Id*., 49 C.F.R. Section 192.505(c).

[82] *Id*., 49 C.F.R. Section 192.517.

[83] Ex. SCG-17 (Rosenfeld, Sempra Utilities), pp. 17, 25.

section 301.1) continued the CPUC's requirement that utilities take responsibility for maintaining the records to establish compliance with the regulations and to be ready to provide such records upon request of the Commission. Section 122.2 (identical to the former section 302.1) continued the requirement that utilities maintain specifications for material and equipment, installation, testing and fabrication. And Section 123.1 continued the requirement to maintain plans regarding MAOP.[84]

The Sempra Utilities suggest that the adoption of the so-called "grandfather clause" in Section 192.619(c) of the 1970 federal regulations somehow signaled to operators that it was no longer necessary to retain pressure test, specifications, and construction records for pre-1970 pipeline.[85] This argument fails for at least two reasons.

First, contrary to the view of the Sempra Utilities, the grandfather clause itself underscores the importance of records. In 1970, Section 192.619(c) stated:

> (c) Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970 . . ..[86]

To comply with this provision, an operator needed to undertake four affirmative obligations: (1) examine and determine that the pipeline segment is in satisfactory condition; (2) obtain and evaluate its operating history; (3) obtain and evaluate its maintenance history; and (4) determine the highest actual operating pressure during the

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[84] D. 78513, issued Jan. 12, 1971, slip. op., App. A, p. 7. Ex. SCG-17 (Rosenfeld, Sempra Utilities), p. 25. There was no need for GO 112-C to replicate former section 303.2, as those requirements were included in the new federal regulations. D. 78513, slip. op., p. 9; *see, e.g.,* 49 C.F.R. Section 192.619.

[85] Ex. SCG-17 (Rosenfeld Rebuttal Testimony, Sempra Utilities), pp. 28-29.

[86] Ex. SCG-30 (Excerpts from 1970 Federal Regulations) (emphasis added). This provision is not substantively different in the current regulations.

five year period. No natural gas system operator can comply with these requirements without creating and preserving accurate and reliable system installation, operating and maintenance records.[87]

Second, the additional record-keeping requirements of GO 112-C (Sections 121 and 122 discussed above) showed that the adoption of the federal regulations did not change California's requirements that operators retain -- and produce on demand -- all records necessary to show compliance with the rules, including pressure test and pipeline specification records.

In sum, from 1955 to the present, standards and regulations applicable to California utilities create an unbroken chain of requirements to retain for the useful life of the pipeline pressure test records to validate MAOP. The 1970 regulations in no way severed that chain, and, if anything, reinforced the importance of record-keeping to ensuring that pipelines are operated at safe pressures.

C. Cost Responsibility: The Sempra Utilities Should Not Recover in Rates Any Costs Resulting from their Inability to Validate Safe Operating Pressures for Pipeline Installed From 1955 to the Present

1. The Sempra Utilities' Failure to Retain Documentation of Pressure Tests for Pipe Segments Installed From 1955 to the Present Is Both Imprudent and a Violation of Applicable Law

Phase 1A of the PSEP consists of pipe segments in populated areas for which the Sempra Utilities are unable to locate adequate documentation of a post-installation

[87] This analysis of Section 619(c) tracks and agrees with the analysis in the recently issued proposed decision ("PD") regarding the proposed PSEP of Pacific Gas and Electric Co. ("PG&E"). Proposed Decision of ALJ Bushey, R.11-02-019, issued Oct. 12, 2012, pp. 98-99.

pressure test to at least 1.25 times MAOP.[88] Put another way, if the Sempra Utilities possessed such documentation, there would be no need for a Phase 1A.

For at least the pipe segments installed in 1955 or later, the Sempra Utilities should possess accessible records of a pressure test. As the following vintage-by-vintage analysis shows, the failure to retain such documentation to validate the safe operating pressure of the pipeline is both imprudent and a violation of the applicable law discussed in the previous section.

1955 – 1961. The Sempra Utilities lack documentation for 234 pipeline segments installed from 1955 to1961.[89] Under the ASME B.31.8 standards in effect beginning in 1955 and continuing to the effective date of GO 112 in 1961, the Sempra Utilities' failure to retain post-installation pressure test records is contrary to Section 841.417 of those standards, which required retention for the life of the pipeline. This failure to follow standards that were well accepted in the industry (including by the Sempra Utilities) constitutes, at a minimum, imprudence and an error or omission under Section 463. In addition, this inability to validate one of the key determinants of MAOP for pipeline of this vintage puts the public safety potentially at risk and therefore violates Section 451's requirement to maintain safe facilities.

1961 – 1970. The Sempra Utilities lack documentation of a pressure test for 151 segments installed from 1962 – 1970.[90] The Sempra Utilities' failure to retain documentation of the post-installation pressure tests required by GO 112, GO 112-A and

[88] Ex. SCG-4 (Schneider Opening Testimony, Sempra Utilities), p. 52; Ex. TURN-1 (Long Test.), p. 15.

[89] Ex. TURN-27 (Sempra Utilities' response to TURN hearing data request).

[90] *Id.* Although the relevant period begins with the implementation of GO 112 in 1961, the Sempra Utilities report this information in TURN-27 beginning in 1962.

GO 112-B from 1961 to 1970 is a clear violation of Section 841.417 of those General Orders, which continued the B31.8 life-of-the-pipeline record retention requirement, as well as Sections 301.1 and 302.1. Even the Sempra Utilities' lead policy witness, Mr. Morrow, had to admit that the inability to document pressure tests for this pipeline vintage constitutes a violation of GO 112.[91]

As explained above, violation of an explicit Commission regulation is undeniably imprudent, as well as an error or omission under Section 463. The inability to document a key determinant of MAOP under GO 112 also violates Section 451.

1970 to the Present. The Sempra Utilities have failed even to comply with the federal regulations requiring detailed life-of-the-pipeline pressure test records for pipe segments installed in 1970 or later.[92] SoCalGas lacks the requisite documentation of a pressure test for 53 such pipe segments, and SDG&E lacks documentation for 14 segments.[93] As with the 1961-1970 segments, Mr. Morrow was forced to concede that the Sempra Utilities' failure to possess the required records for post-1970 segments violates the federal regulations.[94] This failure further violates the post-1970 versions of GO 112 (GO 112-C, GO 112-D, and GO 112-E), which adopt and incorporate 49 C.F.R. Section 192.517.

As is the case with the violations of GO 112, GO 112-A, and GO 112-B, the violation of federal and state regulations is clearly imprudent and an error or omission

[91] Tr., vol. 1, p. 72, lines 1-26 (Morrow, Sempra Utilities).

[92] 49 C.F.R. Section 192.517.

[93] Ex. SCG-13 (Morrow Rebuttal, Sempra Utilities), p. 11, fn. 6.

[94] Tr., vol. 1, p. 72, lines 1-26 (Morrow, Sempra Utilities).

under Section 463. Similarly, the failure to retain documents to support safe operating pressure is a violation of Section 451.

2. California Law Bars the Sempra Utilities From Recovering Any PSEP Costs Resulting From Their Failure to Possess the Records Needed to Validate Safe Operating Pressures

California law does not allow the Sempra Utilities to impose on ratepayers the pipeline testing or replacement costs that result from their imprudent and illegal inability to document pressure tests for pipe segments installed in 1955 or later. As explained above, Commission decisions are clear that utilities may not impose on ratepayers costs that arise from utility imprudence. In case there is any doubt regarding whether such disallowances are mandatory, Section 463 specifies that the Commission "shall disallow" "direct or indirect" costs resulting from utility errors or omissions. Where, as here, the utilities have not merely committed errors or omissions, but have violated Section 451 and specific precautionary safety regulations, the legal mandate to disallow <u>all</u> costs resulting from those violations cannot be questioned.

The disallowance must extend to all PSEP activities that result from the Sempra Utilities' imprudence and violations, including the so-called "accelerated" miles.[95] Accelerated miles represent mileage of pipeline segments that are only included in Phase 1A because they are adjacent to segments for which the Sempra Utilities lack the requisite documentation (which the applicants refer to as "criteria miles").[96] Accelerated miles constitute a large portion of the Phase 1A program, almost doubling the amount of mileage

[95] Ex. TURN-1 (Long Testimony), p. 16.

[96] Ex. SCG-04 (Schneider Direct, Sempra Utilities), p. 52.

identified for action in Phase 1A.[97] The Sempra Utilities claim that these accelerated segments should be addressed at the same time as the criteria segments, as a matter of "operational necessity and project efficiency."[98] It is clear that accelerated miles associated with post-1955 pipe segments would not be addressed in Phase 1A, but for the fact that they are adjacent to segments for which the Sempra Utilities lack the requisite safety records. In other words, absent the Sempra Utilities' violations and imprudence, the post-1955 criteria miles and the associated accelerated miles would not be addressed in the application now before the Commission.[99] Under these circumstances, the law also requires the disallowance of all accelerated miles associated with the post-1955 segments in the Sempra Utilities PSEP.

Based on pipeline segment data provided by the Sempra Utilities and on cost information included in their direct testimony, TURN's testimony presented the following table showing the mileage and estimated PSEP costs for post-1955 segments for which the required safety records are unavailable, as well as the associated accelerated segments.

[97] Ex. SCG-04 (Schneider Direct, Sempra Utilities), p. 53, Table IV-5.

[98] Ex. SCG-04 (Schneider Direct, Sempra Utilities), p. 52.

[99] The Sempra Utilities claim that the "vast majority" of the accelerated miles would otherwise need to be "addressed" in Phase 2. (Ex. SCG-20, Phillips Rebuttal, Sempra Utilities, p. 4). However, as discussed in Section XI below, it is premature for the Commission to assume, let alone conclude, based on the current record that any of the accelerated segments should be tested or replaced in Phase 2.

Table 1
Mileage and Costs for 1955 or Later Pipeline Segments
(Including Associated Accelerated Segments)[100]

Utility / Action	CUM Length (Miles) Cat 4 Criteria	Accelerated	Project Cost (millions) Cat 4 Criteria	Accelerated	Total CUM Length (Miles)	Total Project Cost (millions)
SoCalGas	**60.9**	**36.4**	**$158.2**	**$55.6**	**97.3**	**$213.8**
Installed:1955 to 1960	**30.5**	**20.5**	**$80.7**	**$25.2**	**51.0**	**$105.9**
Pressure or Hydro Test	4.0	0.1	$2.2	$0.0	4.1	$2.2
Replace	19.8	3.9	$74.3	$14.6	23.7	$88.8
TFI Inspect and Pressure Test	6.7	16.6	$4.2	$10.6	23.3	$14.8
Installed:1961 to 1969	**22.2**	**9.9**	**$57.1**	**$13.6**	**32.1**	**$70.8**
Pressure or Hydro Test	2.2	6.8	$1.2	$3.8	9.0	$5.0
Replace	13.9	2.5	$52.0	$9.5	16.4	$61.5
TFI Inspect and Pressure Test	6.1	0.6	$3.9	$0.4	6.7	$4.3
Installed:1970 to 2012	**8.3**	**5.9**	**$20.4**	**$16.8**	**14.2**	**$37.2**
Pressure or Hydro Test	1.9	0.8	$1.0	$0.4	2.7	$1.5
Replace	4.9	4.2	$18.4	$15.9	9.1	$34.2
TFI Inspect and Pressure Test	1.5	0.8	$1.0	$0.5	2.4	$1.5
SDG&E	**16.4**	**0.2**	**$59.7**	**$0.7**	**16.5**	**$60.4**
Installed:1955 to 1960	**13.5**	**0.0**	**$50.5**	**$0.1**	**13.5**	**$50.5**
Replace	13.5	0.0	$50.5	$0.1	13.5	$50.5
Installed:1961 to 1969	**1.4**	**0.0**	**$5.3**	**$0.2**	**1.4**	**$5.4**
Replace	1.4	0.0	$5.2	$0.2	1.4	$5.4
Installed:1970 to 2012	**1.5**	**0.1**	**$4.0**	**$0.4**	**1.6**	**$4.4**
Pressure or Hydro Test	0.5		$0.3		0.5	$0.3
Replace	1.0	0.1	$3.7	$0.4	1.1	$4.1
Grand Total	**77.3**	**36.5**	**$217.9**	**$56.3**	**113.8**	**$274.2**

Table 1 should be treated as illustrative at this point, for the reasons described in Sections IV and V of this brief. The table is based on proposed PSEP cost forecasts that, using the Sempra Utilities' own terms, "are preliminary and were developed based on

[100] Ex. TURN-1 (Long Testimony, p. 17). To calculate costs, TURN used average testing and replacement costs based on the midpoint of the cost per mile ranges shown on page 119 of Exhibit SCG-04 (Schneider Direct). Ex. TURN-1 (Long Testimony), p. 18, fn. 25. As this brief's discussion of the deficiencies of the Sempra Utilities' preliminary cost figures makes clear, TURN does not endorse the accuracy of the Sempra Utilities' claimed costs.

minimal engineering, operational planning, and project execution planning.[101] In addition, the utilities' forecasts reflect initial and tentative assessments about which pipeline segments will be pressure tested and which will be replaced. The criteria for making that determination are still in development and, once developed, will need to be applied in the segment-specific planning and engineering process. Table 1 sets forth the disallowance that would be mandated only if the Commission were to (improvidently) approve as proposed the project activities, scope and costs that are so poorly supported in the application and supporting testimony.[102] If the Commission were to (wisely) scale back the scope of pipeline replacement in the PSEP, particularly for the newer post-1955 pipe segments for which cost disallowances are mandated, the disallowance total would be reduced.

Even the Sempra Utilities concede that some of these disallowances are appropriate. For pipelines installed after 1970 for which the utilities lack the required safety records, the Sempra Utilities are not seeking cost recovery for testing or replacement work.[103] In other words, the Sempra Utilities are self-disallowing these costs.[104] The Sempra Utilities have failed to offer any good reason why cost recovery for post-1970 segments would be inappropriate but cost recovery for segments installed from 1955-1970

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[101] Ex. SCG-9 (Rivera Direct Testimony), p. 103.

[102] The Sempra Utilities' extensive rebuttal testimony does not challenge the accuracy of the numbers in this table.

[103] Ex. SCG-13 (Morrow Rebuttal, Sempra Utilities), p. 11.

[104] Cross examination revealed that, contrary to Mr. Morrow's rebuttal testimony, with respect to replacement and other capital costs, the Sempra Utilities are, in fact, seeking to put such costs in rate base and to collect depreciation, taxes and the established rate of return on those costs. Tr., vol. 1, p.103, line 11 – p. 104, line 10 (Morrow, Sempra Utilities). If any cost recovery is being waived, it is the comparatively miniscule carrying costs that the Sempra Utilities might incur if any of the replacement pipelines are placed in service before the Sempra Utilities' next general rate case. Tr., vol. 9, pp. 1484, line 19 – 1487, line 14 (Reyes, Sempra Utilities).

is warranted.[105] As shown above, in the 1955-1970 period, the violations of the record-keeping requirements of the B31.8 standards, GO 112 and Section 451 are just as clear-cut as are the violations of the post-1970 requirements.

3. The Finding in the Proposed Decision Regarding PG&E's PSEP That Ratepayers Should Pay Most Costs to Replace Post-1955 Pipe Is Unsound as a Matter of Law and Policy and, In Any Event, Should Not Be Followed In This Case

The Sempra Utilities may argue, based on the proposed decision ("PD") regarding the proposed PSEP of PG&E,[106] that, even if recovery of testing costs for post-1955 segments is disallowed, capital costs for replacement pipe should nevertheless be recovered from ratepayers. Under the logic of the PD, ratepayers should not pay for any post-1955 re-testing costs because ratepayers have already paid once for the utilities to comply with the industry standards and regulations that required life-of-the-pipeline retention of pressure test records, but ratepayers should be required to pay replacement costs, minus an adjustment for the estimated costs to pressure test the pipeline slated for replacement.[107] The PD reasons that ratepayers should not receive a new pipeline at no cost.[108]

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[105] In a data request response, the Sempra Utilities offered the following evasive statement about why they are not seeking recovery of post-1970 testing or replacement costs: ". . . given the size and scope of the plan we are proposing, we believed that it was appropriate to not include facilities from 1970 and years later in the plan." TURN-4 (TURN Cross Exhibit), data request response TURN 6-5.c. The attachment to that same exhibit shows that the utilities are foregoing recovery of over $13 million by virtue of this voluntary disallowance. In TURN's experience, utilities do not agree to absorb millions of dollars of costs unless they recognize they have no legal right to claim them.

[106] Proposed Decision of ALJ Bushey, R.11-02-019, issued Oct. 12, 2012.

[107] PD, pp. 61-62.

[108] PD, p. 62.

TURN certainly agrees with the PG&E PD that, at a minimum, the disallowance in this situation (failure to retain required records to document safe operating pressure) should be: (1) all re-testing costs for post-1955 pipe segments; plus (2) an offset of replacement costs by the cost to hydrotest such segments. The unfairness of requiring ratepayers to pay these costs a second time is a good and sufficient reason to disallow costs. But, as explained above, Section 463 mandates disallowance of all "direct and indirect" costs resulting from utility errors or omissions. Likewise, under Section 451's requirement that rates be just and reasonable, the Commission has stated that it would be "unconscionable" to require ratepayers to pay for costs resulting from utility imprudence.[109] It is undeniable that the pipeline replacement proposed in the Sempra Utilities' PSEP would not be necessary in response to D.11-06-017 if the utilities had complied with applicable law and industry standards. Accordingly, it would be legal error to impose costs on ratepayers that result solely from utility violations and imprudence.

Furthermore, it would be supremely poor policy to allow rate recovery for replacement costs. The Sempra Utilities' "preliminary" plans are subject to considerable change, including determinations whether to test or replace segments in Phase 1A. Assuming that all post-1955 testing costs are disallowed (as both the law and sound policy dictate), allowing rate recovery for replacement costs gives the utilities a powerful incentive to replace pipe, even when replacement is otherwise unnecessary. To prevent the utilities from acting on this incentive, the Commission will need to devote significant resources to micromanaging the engineering analysis for each PSEP pipeline segment to

[109] 16 CPUC 2d 249, 283.

ensure that the utilities are not over-designating pipe for replacement in order to obtain cost recovery from ratepayers.[110]

Moreover, the Sempra Utilities have failed to make the case that the post-1955 pipeline at issue would need replacement if they were in possession of the required safety records. The Sempra Utilities have not argued that, as a general matter, post-1955 pipe contains dangerous longitudinal welds or other manufacturing defects that warrant replacement; they only identify <u>pre-1946</u> pipe as having "non state-of-the-art" welds.[111] Furthermore, almost all of the troublesome wrinkle bends are found in pipe installed prior to 1955.[112] To the extent that there are any wrinkle bends or oxy-acetylene girth welds in post-1955 pipe, the Sempra Utilities acknowledge that such issues can be addressed through "surgical replacement" as part of the <u>hydrotesting</u> process.[113] Additionally, in the decision tree, the reason given for replacing pipe is that it cannot be taken out of service for hydrotesting with "manageable customer impact"[114] – not that the pipe is unreliable or unsafe in any way.

In sum, there is no showing in the record that there would be any reason to replace post-1955 pipe in the PSEP if the Sempra Utilities possessed the MAOP validation records that applicable law and standards required them to retain. It would be both legal error and

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[110] There is already basis for concern that the Sempra Utilities' PSEP over-designates pipe for replacement. The Sempra Utilities' PSEP calls for a much higher ratio of pipe to be replaced – 287 miles replace: 359 miles test (see Ex. SCG-33-R (Expanded Decision Tree), Boxes 2, 4, and 4) – than does PG&E's PSEP – 186 miles replace: 783 miles test (PD, p. 17).

[111] Ex. SCG-04 (Schneider Opening Testimony), p. 60.

[112] Ex. SCG- 34-R (Mileage Table requested by ALJ), "Wrinkle Bends" column.

[113] Ex. SCG-04 (Schneider Opening Testimony), p. 55.

[114] Ex. SCG-04 (Schneider Opening Testimony), p. 61, Table IV-1.

the height of unfairness to saddle ratepayers with costs that only arise because of the utilities' violations and imprudence.

4. Ratepayers Should Not Pay for the Costs to Test or Replace Any Pre-1955 Pipeline That Should Have Been Tested Under Integrity Management Requirements

The absence of pressure test records would be both a violation and imprudent if, under Subpart O of the federal regulations, a pressure test was required to assess a potential manufacturing defect in a pipeline segment. The PSEP includes numerous segments with indentified manufacturing threats.[115] Under Integrity Management regulations, a pressure test is one of the means of assessing a manufacturing threat and, in certain cases, may be the only appropriate assessment method.[116] For those pre-1955 segments that should have been pressure tested under Subpart O and that are included in the PSEP because of the absence of such test records, shareholders should bear the consequences of such violations and imprudence.

With respect to the many pre-1955 segments in the PSEP with an identified manufacturing threat, the Sempra Utilities should be required to demonstrate that any testing that should have been conducted under Subpart O would not obviate the need to address the segment in the PSEP. Despite their burden of proof, the Sempra Utilities have not offered any such demonstration in their testimony or workpapers.[117] The Commission

[115] Ex. TURN-1 (Long Testimony, TURN), p. 19 (citing Data Request Response 5-1).

[116] 49 C.F.R. Sections 192.917 and 192.921.

[117] The Sempra Utilities' rebuttal testimony fails to rebut TURN's argument, instead confusing TURN's points with a different DRA argument. (Ex. SCG-18, Schneider Rebuttal, Sempra Utilities), p. 16, fn. 24. TURN does not contend that the PSEP and integrity management (IM) programs have the same scope, but that, if pipe was supposed to be pressure tested under IM, the Sempra Utilities should have retained the records of such pressure tests and ratepayers should not pay for the consequences of the unavailability of such safety records.

should not allow recovery of PSEP costs related to pre-1955 segments with manufacturing threats – and associated accelerated miles – until the Sempra utilities have presented such a showing and the parties have had a chance to review and respond to such showing.

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

In order to meaningfully assess the reasonableness of the Sempra Utilities' Phase 1A recommendations, the Commission needs the "comprehensive analysis of the advantages and disadvantages of potential actions" necessary to make such an assessment.[118] And in order to "be certain that each investment in safety that we order provides value to customers,"[119] the Commission needs an evidentiary record that permits a comparison of the proposed costs with the expected benefits of each such investment. As described below, the Sempra Utilities' showing to date on these points is insufficient to meet these standards.

A. Decision-Making Process (Test or replace, Decision tree)

The Sempra Utilities' decisions on whether to pressure test or replace a pipeline segment turn largely on the utilities' assessment of whether the pressure test could be achieved with "manageable customer impacts." Indeed, for projects deemed part of Phase 1A of the Sempra PSEP, the determination of whether the pipeline is proposed for pressure testing rather than replacement turns on the question of whether the pipeline can be taken out of service "with manageable customer impact."[120] Yet in the utilities initial showing, the "manageable customer impacts" issue was mentioned only in passing, without any

[118] D.11-06-017, p. 17.

[119] Order Instituting Rulemaking 11-02-019, p. 12.

[120] Ex. SCG-04 (Schneider Direct), p. 61; Ex. SCG-20 (Phillips Rebuttal), p. 8.

clear explanation of what the term meant or the criteria the utilities proposed to apply in determining what's "manageable."[121]

A number of parties, including TURN, sought further detail about the process for identifying and assessing "manageable customer impacts," given its prominent and critical role in determining whether a particular pipeline segment would be hydro-tested or replaced. In response to TURN's discovery (following up on similar discovery from DRA), the Sempra Utilities stated that they

> are currently in the process of developing the criteria that will be used to determine whether a pipeline should be replaced or whether it can be taken out of service for pressure testing with manageable customer impacts. It is anticipated that [these] criteria will be included in rebuttal testimony.[122]

It's important to note that the utilities' response clearly contemplates criteria that are still under development, rather than criteria that they had already developed but simply were choosing not to disclose at that time.

Similarly, when TURN asked the utilities to "identify the mitigation measure, if any, to reduce or minimize the customer impact from pressure testing," the Sempra Utilities only said that mitigation measures "were considered when the high level PSEP scope of work was being developed." They did not provide any more detailed information, claiming "Final determination of all customer impacts and the applicable mitigation strategies for these impacts have not yet been determined and will be evaluated as part of the engineering, design, and project execution planning."[123]

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[121] TURN found the term "manageable customer impacts" in four places in the utilities' direct testimony. Ex. SCG-01 (Morrow Direct), p. 19; Ex. SCG-04 (Schneider Direct), pp. 51, 52 and 58.

[122] Ex. TURN-21 (Response to TURN DR 4-4 and 4-6), response to TURN DR 4-4.

[123] *Id.*, response to TURN DR 4-6(c).

The rebuttal testimony used the term "manageable customer impacts" a few times more often than did the direct testimony, but without any material improvement in clarity. After confirming the original decision tree's treatment (that is, that the utilities propose to pressure test pipelines where customer impacts are manageable), the Sempra Utilities explained

> Manageable Customer Impacts means that SoCalGas and SDG&E: (1) will not interrupt service to its core customers in order to pressure test a pipeline; (2) will work with Non-Core customers to determine if an extended outage is possible; (3) will, where necessary, interrupt Non-Core customers for short periods of time as provided for in their tariffs; and (4) will – as is their current practice – work with Non-Core customers to plan, where possible, service interruptions during scheduled maintenance, down time, or off peak seasons.[124]

After the rebuttal testimony was served, TURN followed-up with another data request asking where the testimony set forth the criteria that the Sempra Utilities had promised would be disclosed in the rebuttal testimony. The utilities' response indicated that they had changed their mind:

> Rather than present a rigid set of criteria to define the test or replace decision making process, SoCalGas and SDG&E have outlined several guidelines that provide direction while maintaining flexibility until more experience is gained as program execution progresses.[125]

[124] Ex. SCG-20 (Phillips Rebuttal), p. 3.

[125] Ex. TURN-23 (Response to TURN DR 8-1), Response 8-1(a). TURN notes that the approach the Sempra Utilities described here is consistent with the approach TURN recommends for more general application here: The Commission should defer making final decisions on aspects of the utilities' proposals until they have gained more experience with PSEP projects and present proposals that are informed by the results of that experience.

Not surprisingly, in TURN's view, the Sempra Utilities could provide no documentation of either the process for identifying or selecting potential criteria for purposes of assessing manageable customer impacts.[126]

The upshot of this is that the Commission should defer action on the Sempra Utilities' proposed decision tree at this time. The determination of whether to pressure test or replace a line is a key decision for each and every pipeline that is a subject of the plan. Yet according to the decision tree, the utility's decision will rely upon an assessment of whether there are "Manageable Customer Impacts," a predicate decision that would rely on what started off as promised-but-not-unveiled criteria, but ultimately were merely "guidelines that provide direction" that could be expected to further evolve as more experience is gained. The Commission cannot make an informed judgment about the reasonableness of the proposed costs for the PSEP where such a substantial portion of those costs depend on the outcome of the "replace or pressure test" decision, a decision that requires the utilities to make a reasonable assessment based on criteria that they have failed to adequately identify, much less demonstrate to be reasonable themselves.

In another key area, the utility-proposed Decision Tree should be rejected because its application of "manageable customer impacts" is overly restrictive. According to the Sempra Utilities, "at this early stage, it is unwise to create an overly prescriptive approach to the decision to test or replace a pipeline segment…."[127] Yet the first "guideline" identified in the rebuttal testimony is that service to core customers will never be interrupted in order to permit a pressure test.[128] And it seems that the Sempra Utilities

[126] *Id.*, Response 8-1(e) and 8-1(g).

[127] Ex. SCG-20 (Phillips Rebuttal), p. 3.

[128] *Id.*

intend to take this approach "regardless of the cost."[129] The Commission should anticipate that there may be circumstances, perhaps rare, under which it would make sense to at least consider interrupting core customers, where the cost savings from pursuing pressure testing rather than replacement are great and the impact on the core customers, while not desirable, is relatively small. But under the Sempra Utilities' Decision Tree and the underlying concept of "manageable customer impacts," no such option would be considered.

B. Review of Decisions (Engineering Advisory Board, Annual Reports, Expedited Advice Letters)

The Sempra Utilities propose that the Commission's review of the PSEP at this stage serve as the likely exclusive opportunity for the agency to address the utilities' decision-making process. There would be no clear opportunity for the Commission to assess the reasonableness of the utilities'' funding decisions, either before or after funding decisions are made, once this decision issues. The utilities have sought to create the appearance of ongoing Commission oversight, in the form of an "Engineering Advisory Board" and annual reports to the agency. But the bottom line is that under their approach, the utilities would never need to come back to the Commission to obtain approval for any project that is deemed part of Phase 1A, so long as the utilities stay within their combined forecast of approximately $1.7 billion of projected direct costs for that phase.[130]

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[129] Morrow, Sempra Utilities, 1 RT 136, ll. 14-19.

[130] Buczkowski, Sempra Utilities, 5 RT 860, ll. 5-15.

1. Engineering Advisory Board

The Commission should decline the Sempra Utilities' invitation to embrace the recently unveiled "Engineering Advisory Board" (Board) as a meaningful opportunity to review or influence their implementation of the PSEP as approved in a Commission decision.

The 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.[131] The utilities propose a four-member board with a representative of the Commission's Consumer Protection and Safety Division (CPSD) and Energy Division, and with an outside consultant.[132] But the utilities have not discussed even the concept of the proposed board with CPSD, Energy Division, or any outside consultants.[133]

If CPSD or Energy Division believes that a Board as proposed by the Sempra Utilities would serve a useful function for them as they help implement the PSEP, TURN would not oppose creating such a Board for that purpose.[134] But for ratemaking purposes such as determining which projects and which project costs are just and reasonable, the Board is of no value.

The Board proposal is premised on several assumptions that lack factual support. For starters, it is not clear what significance such Board review would provide. Having

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[131] Phillips, Sempra Utilities, 6 RT 1113, l. 25 to 1114, ll. 21; Ex. TURN-22 (TURN DR 7-2).

[132] Ex. SCG-20 (Phillips Rebuttal), p. 15.

[133] Ex. DRA-31 (Data Request Responses), DR DBP-4-5.

[134] As ALJ Long indicated during the hearings, the Commission might still need to weigh whether the potential value of such a Board outweighs the risk of the Board creating a distraction that might keep the utilities from making the most prudent and best informed decisions in implementing their PSEP. ALJ Long, 7 RT 1246, ll. 5-16.

Commission staff participating as members of the Board does not provide such significance; as the Commission has noted before, "the staff does not speak for the full Commission."[135]

To the extent the Sempra Utilities would have the Commission rely on the CPSD or Energy Division Board members to raise an alarm should the Board review indicate cause for concern with the utilities' implementation of any element of PSEP, there are two distinct problems. First, the Sempra Utilities have "assumed that if the CPSD or energy [division] 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 to the Commission."[136] TURN is not aware of any such mechanism, and nowhere did the Sempra Utilities further identify or describe the mechanism they have in mind. The Commission should not rely on such a process when it is premised upon an ability to bring matters to the Commission's attention that either may not exist or, at the very least, may not be very efficacious.

Second, 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.[137] If the Engineering

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[135] D.01-08-067 (in C.00-08-053), 2001 Cal. PUC LEXIS 517, *46 (Pacific Bell had relied on conversations it had had with Telecommunications Division staff, which led to the Commission's reminder that staff does not speak for the Commission.)

[136] Phillips, Sempra Utilities, 6 RT 1096, ll. 20-27.

[137] The general rule is that "powers conferred upon public agencies and officers which involve the exercise of judgment or discretion are in the nature of public trusts and cannot be surrendered or delegated to subordinates in the absence of statutory authorization." *Cal. Sch. Employees Assn. v. Personnel Comm'n* (1970) 3 Cal. 3d 139, 144, *as quoted in* SCE Application for Rehearing of D.12-05-037 (EPIC Phase 2 Decision in R.11-10-003), July 2, 2012, pp. 14-15.

Advisory Board works as the Sempra Utilities clearly hope it will, the vast majority of projects and actions reviewed by the Board would be deemed not worthy of even attempting to obtain further Commission review. And for those projects or actions, the Board would be effectively exercising its judgment or discretion in determining the reasonableness of the projects or actions. This would be an inappropriate and unlawful delegation of the Commission's authority.

2. Annual Reports

3. Expedited Advice Letters

The Sempra Utilities' direct testimony devoted a few sentences to describing advice letters that would serve as the vehicle for ratemaking relief should they find themselves needing more-than-authorized revenue requirements for the PSEP. They

> propose to file expedited advice letters requesting approval for any adjustments to the overall level of Pipeline Safety Enhancement Plan funding requirements previously approved. These advice letters will include an explanation for changes from the original revenue requirements, as previously proposed and approved. We also proposed to use this advice letter process in requesting any additional revenue requirement associated with the Enterprise Asset Management System or the expansion of the Pipeline Safety Enhancement Plan for pipeline safety enhancement activities not covered by this filing that may subsequently be adopted by the Commission.[138]

According to General Order 96-B, advice letter treatment is appropriate for matters that are "the types of utility requests that are expected neither to be controversial nor to raise important policy questions."[139] The Commission should conclude, based on the record established to date, that a Sempra Utilities request to increase its authorized funding

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[138] Ex. SCG-10 (Reyes Direct Testimony), p. 127.

[139] General Order 96-B, General Rules, Section 5.1.

for PSEP activities will likely be controversial and raise important policy questions. According to the utilities, the expedited advice letter would need to explain the variance between recorded and estimated costs, and the reasons why the estimated costs are now proving too low.[140] Thus to the extent the utilities seek increases because costs for anticipated activities turned out to be higher than originally estimated, parties and, ultimately, the Commission will need to address whether those higher-than-anticipated costs are reasonable rather than, say, attributable to mismanagement or inefficiency on the utility's part.

The Sempra Utilities were unable to identify any example of another expedited advice letter process.[141] The utilities acknowledge that their proposal could result in parties and the Commission having very little time available to review potentially large increases in rates.[142] The Commission should conclude that the proposal for an expedited advice letter process in order to increase authorized revenue requirements (or for any other purpose here) is not adequately supported and should be denied.

4. Audits

The Sempra Utilities made several references to the possibility of the Commission achieving some amount of regulatory oversight through audits of their ongoing implementation of the PSEP.[143] TURN did not see any mention of such audits in either the prepared direct or rebuttal testimony for the utilities, so this appears to have been a

[140] Reyes, Sempra Utilities, 9 RT 1564, ll. 8-15.

[141] *Id.*, at 1494, l. 26 to 1495, l. 4.

[142] *Id.*, at 1535, ll. 20-23.

[143] *See*, *for example*, Buczkowski, Sempra Utilities, 6 RT 1052, ll. 17-24; Rivera, Sempra Utilities, 8 RT 1360, ll.21 to 1361, l. 2.; and Reyes, Sempra Utilities, 9 RT 1511, ll. 5-23.

stratagem developed for the witness stand. Be that as it may, the Commission should reject the notion that such audits would be a useful tool in addressing the cost/benefit, cost estimating and cost control issues that intervenors have raised directly or indirectly in this proceeding.

The Sempra Utilities made very clear during the evidentiary hearings that an "audit" as they use the term is limited to a review of the accuracy of recorded charges in respective regulatory accounts, and <u>not</u> the reasonableness of those charges.[144] So to the extent parties have raised issues and concerns about the reasonableness of the proposed TSEP programs, costs, decision-making, or anything other than the accuracy of the recorded costs, the possibility that the Commission might some day audit the utility's activities provides no resolution of those issues and concerns.

TURN recognizes that there is a relatively small subset of disputed issues in this proceeding for which "audits" might serve as part of the appropriate resolution. Most obviously, where parties have raised valid issues about whether costs will be correctly recorded to PSEP activities rather than, say Transmission Integrity Management Program (TIMP) activities, an audit that will review how and where those costs were recorded might produce useful information. So to be clear, TURN is not arguing that an audit, or even the threat of an audit, would be of no value in all circumstances for all issues. But the Commission must firmly reject the notion that the possibility of a future audit is any sort of a substitute for either closer up front scrutiny of the proposed PSEP activities and funding levels or an after-the-fact reasonableness review.

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[144] Reyes, Sempra Utilities, 9 RT 1592, ll. 8-21.

C. Base Case

The "Base Case" included in the Sempra Utilities' proposal is intended to cover work the utilities deem required by D.11-06-017:

- testing or replacing pipeline segments for which the utilities lack the required documentation of pressure testing;
- interim safety enhancement measures;
- development of in-line inspection (ILI) for "piggable" pipelines, and
- a Valve Enhancement Plan that would install automatic shutoff valves (ASV) or remote control valves (RCV) on larger-diameter, higher-pressure transmission pipeline segments.[145]

TURN addresses each of these elements in the sections that follow.

1. "Test or Replace": The Testing or Replacement of Pipeline Segments Proposed As Part of the "Base Case" Suffers From The Same Deficiencies TURN Has Described Generally Regarding The Decision-Making and Decision-Review Processes in the Sempra Utilities' PSEP Proposal.

TURN's criticisms of the decision-making process and the decision-review process, set forth in the preceding two sections, apply most directly to the Sempra Utilities' proposals for testing or replacing pipeline segments. Rather than repeat those arguments here, TURN incorporates them by reference.

[145] Ex. SCG-9 (Rivera Direct Testimony), p. 105. The Base Case does not include costs associated with 1) mitigating pre-1946 construction and manufacturing methods, 2) proposed "technology enhancements," or 3) the development and design of an Enterprise Asset Management System.

2. Interim Safety Enhancement Measures: The Vast Majority of the Costs Labeled “Interim Safety Enhancement Measures” Are In Fact Records Search Costs That Should Not Be Included In Rates Due to the Prohibition Against Retroactive Ratemaking, The Connection To Past Utility Imprudence, And A Failure To Demonstrate The Reasonableness Of The Costs.

When the Sempra Utilities describe their proposed “interim safety enhancement measures,” they tend to focus on efforts such as increased ground patrols and leakage surveys. But as it turns out, the vast majority of costs included in the “interim safety enhancement measures” category for the 2011-2015 period are costs associated with records search and retrieval costs in response to CPUC Resolution L-410, an effort expected to be completed in mid-2012.[146] The Commission should address the two sub-categories separately, and should specifically and clearly deny rate recovery of the records review costs.

The Sempra utilities deem “continued use of our proposed interim safety measures” as one of the “key elements” of the PSEP for which they seek Commission approval.[147] The description of these measures in the “Introduction and Executive Summary” chapter of the direct testimony emphasized activities such as pressure reductions, increased ground patrols and leakage surveys, and in-line inspections.[148]

However, the cost recovery sought for this category is broader in scope, as the Sempra Utilities seek “the recovery of costs incurred to date, and to be incurred up to the

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[146] Ex. SCG-32 (Sempra Utilities Workpapers), p. WP-IX-4-3 (“For the data mining effort, assumed data mining costs … through July 2012. It was then assumed to be complete.”)

[147] Ex. SCG-1 (Morrow Direct Testimony), p. 3.

[148] *Id.*, p. 4. The direct testimony chapter entitled “Proposed Transmission Pipeline Enhancement Plan” further explained that the “proposed interim safety measures” would also include ongoing work through the Transmission Integrity Management Program, but no incremental funding was sought for that work because the program is authorized through the utilities’ respective GRCs. Ex. SCG-4 (Schneider Direct Testimony), p. 64 and fn. 48.

time the Commission issues a decision."[149] And the Sempra Utilities identified two distinct categories of activities that would result in such costs: "the review of transmission pipeline records and … implementation of our interim safety enhancement measures."[150] According to the "Introduction and Executive Summary" testimony, as of the date the amended testimony was served in late 2011, the Sempra Utilities had recorded $3 million of such costs and forecasted an additional $7 million to be spent by "year-end" in these two categories.[151]

The "Cost Estimate" chapter of the direct testimony confirms that the amounts included under the heading "interim safety enhancement measures" include costs associated with the "extensive records review" in addition to costs of the safety measures themselves.[152] The testimony shows total costs of $10.55 million for SoCalGas and $1.42 million for SDG&E for the "Phase 1 Interim Safety Enhancement Measures" for 2011-2015, with more than 95% of those costs associated with 2011 and 2012. But the testimony does not indicate the portion of these costs that are for "records review" activities distinct from "interim safety enhancement measures."

The workpapers for this chapter further reveal that "records review" costs represent more than 95% of the costs associated with this "interim safety enhancement measures" category. Of the nearly $12 million sought as costs of "interim safety measures" for the two utilities, over $11 million represents records review costs.[153] Put another way, of the

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[149] Ex. SCG-1 (Morrow Direct Testimony), p. 5.

[150] *Id.*, pp. 5-6.

[151] *Id.*, p. 6.

[152] Ex. SCG-9 (Rivera Direct Testimony), p. 111.

[153] Ex. SCG-32 (Sempra Utilities Workpapers). For SoCalGas, the total "interim safety measures" figure is $10.551 million (p. WP-IX-4-1), of which $9.685 million is for "records search" costs

$11.97 million of total costs in this "interim safety enhancement measures" category, $0.90 million represent the incremental costs of interim safety measures other than the record search costs incurred in 2011 and 2012.[154]

The Commission must decline the request to provide rate recovery at this time for $11 million of records review costs, for several reasons. First, a substantial portion of these costs was incurred prior to the Commission granting authority to the Sempra Utilities to establish the Pipeline Safety and Reliability Memorandum Account. Therefore rate recovery of that portion of the costs is prohibited by the retroactive ratemaking rule. TURN presented the retroactive ratemaking arguments in the response jointly filed with DRA to the Sempra Utilities' motion seeking rate recovery of the costs recorded in the memorandum account, filed June 11, 2012. Rather than restate those arguments here, TURN incorporates them by reference.

Second, the Sempra Utilities have not met their burden of demonstrating that these costs are reasonable, rather than resulting from their own imprudent record-keeping practices. In fact, the utilities chose not to present any testimony at all describing the nature of the activities that caused the "records review" expenses to be incurred. According to their own report, significant time and resources may have been spent searching for records that should have been retained but may no longer exist or, at a minimum, are not readily accessible.[155] A prudent pipeline operator would have an effective record-keeping system

($8.38 million + $1.254 million + $0.051 million, from pp. WP-IX-4-3 to -4-5). For SDG&E, the total "interim safety measures" figure is $1.422 million (p. WP-IX-4-12), of which $1.387 million is for "records search" costs ($0.465 million plus $0.922 million, from pp. WP-IX-4-14 to -4-15).

[154] $11.973 million - $9.685 million - $1.387 million = $0.901 million. SDG&E's non-records search "interim safety measures" forecast for 2011-15 is $37,000 (thirty-seven thousand).

[155] Ex. TURN-01 (Long Testimony), p. 21, citing the Sempra Utilities' April 15, 2011 report from R.11-02-019.

that ensures that such critical records are not only preserved for the life of the pipeline, but can be easily accessed. Ratepayers should not pay for costs resulting from imprudent record-keeping.[156] Under the circumstances, the Commission can only conclude that the utilities have failed to meet their burden of demonstrating that these costs are the product of prudent utility management practices, and deny rate recovery of the "records review" expenses.

Third, even if the Commission were to assume that prudence issues do not prohibit rate recovery of the reasonable costs associated with the Sempra Utilities' "records review" effort, it should still deny recovery because the utilities have not met their burden of presenting evidence that would demonstrate the reasonableness of the costs incurred due to the records search effort. The direct testimony fails to clearly identify the amount of costs associated with the records search activities in 2011 and 2012. The workpapers have a year-by-year listing of the total costs associated with records search activities, but the very limited narrative that appears in those workpapers merely describes the various components of the total costs without the detail required to assess reasonableness, much less to support a finding of reasonableness.

Fourth, whether intentional or not, the Sempra Utilities approach on these issues was so confusing as to appear deceptive. As noted earlier, over 90% of the costs within the "Interim Safety Enhancement Measures" category were in fact costs associated with the records review. Nothing in the utilities' testimony made this clear; instead, it took a not insubstantial amount of time and effort to piece together the testimony to understand that the cost estimates put forward here include the same "records search" costs that are the

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[156] *Id.*, pp. 21-22.

subject of the pending motion. When a proposed decision in R.11-02-019 threatened to assign these costs to the utilities and their shareholders, the utilities' comments urged the Commission to give the utilities a chance to present "rebuttal testimony" in this proceeding.[157] But nothing in the rebuttal testimony addresses the reasonableness of the costs incurred to-date for records review, or of any cost forecast associated with the records review. Whether or not the utilities convince the Commission that the records review itself was not the result of imprudence, that determination does not address the question here, that is, the reasonableness of the costs incurred to perform the records review.

3. TURN Supports Further Exploration of In-Line Inspection Technologies.

The Sempra Utilities describe approximately 200 miles of transmission pipeline segments that lack sufficient documentation but are already configured to allow for in-line inspection and have previously been inspected with a magnetic flux leakage (MFL) in-line inspection tool.[158] The utilities propose to use the scheduled re-assessment of these segments as an opportunity to utilize a transverse flux (TFI) in-line inspection tool (in addition to the MFL tool) to conduct further evaluation of the condition of the pipe. Following these in-line inspections, a pressure test will be performed. The Sempra Utilities hope the results of the various evaluations demonstrate that an in-line inspection can substitute for a pressure test, achieving the same effectiveness at a lower cost.[159] The goal would be to pursue the TFI inspections in the near-term so that the resulting data will

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[157] *Id.*, p. 23, citing Comments of SCG and SDG&E on PD Transferring Consideration of PSEP to the Triennial Cost Allocation Proceeding, filed April 9, 2012, R.11-02-019, pp. 5-6.

[158] Ex. SCG-9 (Rivera Direct Testimony), p. 110.

[159] *Id.*, p. 111.

be available in the next GRC so that the Commission could then act on a request to modify General Order (G.O.) 112-E to permit the use of TFI in lieu of pressure testing.[160] The Sempra Utilities estimate $5 million as the O&M costs of the TFI "runs," with an additional $3 million for associated "validation digs." The utilities also estimate these efforts will result in one excavation and repair per mile, at a total cost of $54 million.[161]

TURN supports this aspect of the Sempra Utilities' proposal, subject to the general proviso that the associated costs must be reviewed for reasonableness either before- or after-the-fact. The cost of an in-line inspection is substantially lower than the cost of a pressure test. If the Commission can determine that the results of an in-line inspection are similarly reliable as the results of pressure testing for purposes of assessing the condition of an existing pipeline segment, the overall cost of the assessment would decline. This is a preferable outcome regardless of whether ratepayers or the utilities are bearing the cost of the inspections. The $5-8 million of incremental costs is relatively small compared to the magnitude of the total project costs at issue here, and seems like a worthwhile investment that has a reasonable chance of proving to be cost-effective should the results permit reliance on in-line techniques in lieu of pressure testing.

4. Valve Enhancement Plan

The Sempra Utilities propose a Valve Enhancement Plan under which they would convert some 347 manually-operated valves to either automatic shutoff valves (ASV) or remote control valves (RCV), upgrade 94 existing ASV with RCV functionality, upgrade

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[160] Phillips, Sempra, 7 RT 1156, ll. 15-25.

[161] Ex. SCG-9 (Rivera Direct Testimony), p. 111, Table IX-9.

100 ASV with communication capability, and adding 20 ASV or RCV to the system.[162] The Phase 1A cost forecast associated with the Valve Enhancement Plan is $150 million, allocated $123.0 million to SoCalGas ($121.0 million capital, $2.0 million O&M), and $27 million to SDG&E ($26.0 million capital, $1.0 million O&M).[163]

TURN shares the position taken by CPSD (CPSD) in its report on the Sempra Utilities PSEP. While CPSD found the Valve Enhancement Plan was generally well reasoned, the staff raised issues regarding the Sempra Utilities preference for RCV over ASV. As the utilities testimony illustrates, ASV technology substantially reduces the timeline as compared to RCV technology.[164] However, the Sempra Utilities err on the side of reducing the potential for false closures and therefore opt for RCV. According to the CPSD report, if the Commission were to accept some risk of false closures, the same level of improved safety could be achieved by installing approximately half the shutoff valves proposed by Sempra.[165]

TURN urges the Commission to adopt the principle that reliance on ASVs is the preferred approach where feasible. The agency should also direct CPSD and the utilities to work together to further evaluate the CPSD's proposal with the goal of reducing the number of RCVs installed and thereby increase the potential cost-effectiveness of this element of the Sempra Utilities' PSEP without sacrificing safety.

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[162] Ex. TURN-02 (Marcus Testimony), p. 9, citing Ex. SCG-05 (Rivera Direct Testimony), p. 81, Table V-1.

[163] Ex. TURN-02 (Marcus Testimony, p. 9.

[164] *Id.*, citing Ex. SCG-05 (Rivera Direct Testimony), p. 69, Figure V-1.

[165] *Id.*, p. 10.

i) False closure issue

In order to avoid service disruptions due to false closures or valve malfunctions, the Sempra Utilities have in the past avoided installing ASVs on pipelines where there are multiple taps and pipeline interconnection points that are critical to serving customers.[166] While the general notion of avoiding outages due to valve problems might seem reasonable in isolation, such a "no outages, at any cost" approach is problematic whether applied to the "pressure test or replace" determination or the choice of type of valve. There are safety, cost and other concerns that must also be taken into account in any analysis of the options. The Sempra Utilities have failed to present such an analysis of the options for the Valve Enhancement Plan. They have also never collected sufficient information to evaluate whether false closures from ASVs are a significant problem.[167]

Also missing from the Sempra Utilities' showing in support of its Valve Enhancement Plan is an analysis of the cost-effectiveness of choosing RCVs rather than ASVs. As the CPSD Report noted, ASVs would permit the valves to be installed farther apart than would be the case with RCVs, leading to a potential cost savings. These and any other benefits of an ASV approach should be compared to the reliability impacts, if any, and any other potential detriments from using ASVs rather than RCVs. The Sempra Utilities presented no such analysis here.

Such an analysis would seem a great opportunity to put into effect the utilities' stated intention of working closely with CPSD on potentially reducing the number of shut-

[166] Ex. TURN-02 (Marcus Testimony), citing Ex. SCG-05 (Rivera Direct Testimony), p. 75.

[167] Ex. TURN-02 (Marcus Testimony), p. 11, citing CPSD Report, p. 15.

off valves on their transmission pipeline systems.[168] But the Sempra Utilities and CPSD have had "no formal communication on mutual design efforts to date."[169]

In sum, while the Commission may agree with the notion that, all else equal, the utility should choose the option that better reduces the risk of service outages, before approving that option it needs to assess whether all else is really equal. Even if the Sempra Utilities are correct that the RCVs have reliability advantages over ASVs, the Commission should direct them to demonstrate that these advantages are sufficient to outweigh any costs in terms of higher costs to ratepayers or safety concerns.

ii) Cost estimates

The Sempra Utilities developed their cost estimates for the Valve Enhancement Plan in an odd way, averaging their own estimates with the estimates provided by a third-party contractor (whose estimates were significantly below those of the utilities).[170] In their rebuttal testimony, the utilities argued that such concerns can be ignored, given that the average recorded costs of early projects are relatively close to the $1.17 million forecasted cost per project they had developed.[171] But the underlying costs of seven projects ranges from $600,000 (approximately half the forecasted cost) to $1.7 million (approximately 50% higher than the forecasted amount).[172] Given that range, plus the fact

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[168] *Id.*, p. 16, citing Comments of SoCalGas Company and SDG&E Company on the CPSD Technical Report, 1/27/2012, p. 10.

[169] Ex. TURN-25, Response to DR TURN-07-014.

[170] Ex. TURN-02 (Marcus Testimony), p. 13. As explained in TURN's testimony, the Commission should reject the Sempra Utilities' explanation that the differences between the estimates is attributable to differences in the scope of work covered by each estimate. The cost estimates cover equivalent scopes of work, yet the contractor-provided estimates are approximately 40% less than the Sempra-provided estimates. *Id.*, p. 14.

[171] Ex. SCG-23 (Rivera Rebuttal Testimony), pp. 9-10.

[172] Ex. DRA-34 (Responses to DR KCL-05), Table 05-03; Rivera, Sempra Utilities, 7 RT 1303, l. 27 to 1304, l. 10 (the average was derived using the first seven projects listed in the table).

that there are only seven data points for recorded costs but hundreds of projects within the Valve Enhancement Program, the Commission should give very little weight to the utilities' claims that the recorded costs to date have affirmed the accuracy of the forecast.

iii) Conversion of ASVs to RCVs

The Sempra Utilities request authorization to spend in excess of $21.0 million to convert ASVs to RCVs without having first performed the detailed engineering study that they themselves said was necessary to analyze and implement the correct policy. There is no information suggesting that this conversion will improve safety, but absolute certainty that it will cost money.[173] Therefore, the Commission should 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.

D. Proposed Case

The Sempra Utilities offer two versions of the Pipeline Safety Enhancement Plan, with the "proposed case" including "additional safety enhancing elements … that are not required under D.11-06-017."[174] The utilities acknowledge that these technology enhancements included in the Proposed Case "will increase the costs of implementing the PSEP above the Base Case," they describe the proposals as seeking to take advantage of "a unique opportunity for us to cost effectively retrofit our transmission pipelines with the

[173] Ex. TURN-02 (Marcus Testimony), p. 16.

[174] Ex. SCG-01 (Morrow Direct Testimony), pp. 13-14.

latest state-of-the-art technology for sensing conditions that could lead to a pipeline failure long before such a failure might occur."[175]

1. Inclusion of Accelerated Miles

The Sempra Utilities propose to prioritize their PSEP activities into Phase 1A, Phase 1B, and Phase 2. In Phase 1A the utilities intend to address "all transmission pipelines in populated areas that do not have sufficient documentation to validate a post-construction pressure test of at least 1.25*MAOP" and "represent the highest priority work."[176] But the utilities propose to include more than just the pipeline segments that meet the criteria for Phase 1A in their Phase 1A work, as they indicated in two identical footnotes:

> In some circumstances, Phase 2 pipeline segments may be addressed as part of Phase 1, in light of operational and economic considerations. For example, a relatively long pipeline segment may run through both heavily populated areas and sparsely populated areas. In such cases, it may be more economical and practical to pressure test that entire segment at one time, rather than to remove the line from service to pressure test solely the portions that run through populated segments in Phase 1, and then remove the line from service a second time in Phase 2 to pressure test the portions that run through less populated areas.[177]

These Phase 2 segments for which it might turn out to make sense to deal with at the same time nearby Phase 1A work is being performed were referred to as "accelerated miles," as distinct from the "criteria miles" that met the NTSB criteria.[178] And the Sempra Utilities' proposed case seeks to include the accelerated miles in the scope of Phase 1A.

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[175] *Id.*, p. 15.

[176] Ex. SCG-04, (Schneider Direct), p. 52.

[177] *Id.*, p. 51 (fn. 45) and 62 (fn. 46).

[178] Ex. SCG-04 (Schneider Direct), p. 49.

TURN's testimony agreed that, in theory, this strategy could potentially make sense. But before proceeding under this theory, TURN asserted that the Sempra Utilities needed to present some more fully developed analysis of the economics and customer impacts of the strategy, none of which was included in their direct showing.[179] Discovery revealed that the "acceleration proposal" had not yet been the subject of any "specific analyses or studies [] performed to determine that it is more economical and practical to accelerate Class 1 and 2 non-[high consequence area] segments into Phase 1A." Rather, "[t]he Accelerated miles in the PSEP filing were identified based on a high level definition of the project scope."[180]

A more rigorous analysis from the utilities and vetting of that analysis by intervenors and the Commission is particularly critical where, as here, the exceptions appeared to swallow the rule. As described in the utilities direct testimony, the number of "accelerated miles" proposed for pressure testing as part of Phase 1A was very nearly the same as the number of "criteria miles." And on its face, the direct testimony proposed replacement of a <u>greater</u> number of "accelerated miles" than "criteria miles" in Phase

[179] The footnoted material quoted above was the extent of the explanation in the direct testimony.

[180] Sempra Utilities' response to Data Request DRA-DAP-9-1(d), as quoted at Ex. TURN-02 (Marcus Testimony), p. 19.

1A.[181] The utility-calculated amounts of direct spending also showed higher cumulative figures for "accelerated miles" included in Phase 1A as compared to "criteria miles."[182]

The Sempra Utilities confirmed that TURN's concern had merit: "SoCalGas and SDG&E did not perform specific studies prior to filing it's [sic] PSEP to illustrate economic and project efficiencies resulting from accelerating these miles."[183] They explained that at this stage they had relied on "expertise and engineering judgments by subject matter experts who are knowledgeable about our system."[184] The fact that the guesses were made by subject matter experts does not ameliorate the problem, though, and absent the specific studies assessing the economic and customer impacts of a particular segment proposed for acceleration, all the Commission has are each utility's best guess based on what is known at this time.

The Sempra Utilities' rebuttal also described estimates it had calculated increased costs under scenarios that had segments proposed for acceleration here instead left for Phase 2.[185] But as the utilities note, the sample size considered in developing these estimates is so small as to render the results of dubious value for the Commission's purposes here. And the fact that the calculations "utilized a cost estimate methodology

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[181] Ex. TURN-02 (Marcus Testimony), p. 17, citing Ex. SCG-09 (Reyes Testimony), Table IX-5 (p. 108) and Table IX-7 (p. 110). The utilities rebuttal testimony explained that some of these numbers made the proportion of accelerated miles appear higher because the utilities had included "new pipe construction." Removing the "new pipe construction" lowers the ratio somewhat. Ex. SCG-20 (Phillips Rebuttal), p. 21. However, the "new pipe construction" explanation does not change the more important point; the accelerated pipeline segments represent a very substantial portion of the total pipeline segments that the Sempra Utilities propose to include within the scope of Phase 1A.

[182] Ex. TURN-02 (Marcus Testimony), pp. 17-18.

[183] Ex. SCG-23 (Phillips Rebuttal), p. 17.

[184] *Id*.

[185] *Id.*, pp. 18-19.

consistent with that presented in the filing and workpapers" might be good for consistency's sake, but given the concerns about the quality of the cost estimating methodology and analysis in the filing and workpapers, the Commission should require a more reasonable and rigorous analytical approach to these questions.

This is another area in which the Sempra Utilities ask for authorization based on what they have presented in this proceeding before they have completed the analysis necessary to make an actual decision. Yet they propose that there would not be any subsequent review of the reasonableness of the decisions once they are actually made, or of the reasonableness of the execution of that decision, including the reasonableness of the costs incurred in the effort.

The Commission should instead permit the Sempra Utilities to propose inclusion of "accelerated miles" on a project-specific basis once they have completed the engineering and planning for each project and seek Commission approval of that project. This would permit the Commission to assess the reasonableness of the actual proposal for "accelerated miles" and avoid the pitfalls of attempting to assess the inclusion of accelerated miles on the more theoretical basis that exists as of today.

2. Technology Enhancements – Fiber Optics and Methane Detectors

The Sempra Utilities' direct testimony proposed several "technology enhancements" based on their belief that "monitoring events and pipeline system status for purposes of safety enhancement, as opposed to solely for operational purposes, can provide added value in the management of the integrity of their pipeline assets."[186] On that basis,

[186] Ex. SCG-06 (Rivera Direct), p. 85.

the utilities propose to install fiber optic cabling and methane detection instruments over a ten-year period, and to develop a data collection and management system (DCMS) to collect information from the field monitoring sensors.[187]

The core problem with the Sempra Utilities' proposed technology enhancements (dubbed the "Technology Plan" in the rebuttal testimony) is that the utilities have made no attempt to assess whether the benefits that might be achieved under the plan make the costs worthwhile. The costs are real and not insubstantial -- $26.8 million of capital and $1.3 million of O&M for the fiber optics, and $9.6 million of capital and $0.9 million of O&M for the methane detectors.[188] But the benefits are generally aspirations at this stage; for example, "[t]he safety of the SoCalGas/SDG&E system <u>may</u> be further enhanced through the addition of real-time pipeline right-of-way gas detection monitors…."[189]

The Sempra Utilities claim that their "Technology Enhancement Plan" proposals are consistent with the scope of the Order Instituting Rulemaking (OIR) that began the PSEP process, and the directive in D.11-06-017 to pursue <u>interim</u> safety enhancement measures.[190] Even if the utilities were correct in their suggestion that the installation of fiber optic and methane detection technology is of the same nature as increased patrol and leak surveys and the other examples the Commission provided of "interim" safety measures, the Commission should reject their position for failure to consider another central tenet of the Order Instituting Rulemaking:

> Given the economic challenges confronting California's families and businesses, we must be certain that each

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[187] *Id.*, pp. 85 and 87.

[188] Ex. TURN-02 (Marcus Testimony), pp. 25-26.

[189] *Id.*, p. 86.

[190] Ex. SCG-23 (Rivera Rebuttal), pp. 15-16.

> investment in safety that we order provides value to customers.[191]

The utilities failed to present any evidence of the value to customers of the fiber optics and methane detection monitors, much less evidence demonstrating that the value to customers warrants incurring the cost. Therefore the Commission should not adopt the proposals at this time.

i) Fiber Optics

The central point of the Sempra Utilities' analysis to support their fiber optic technology proposal is that it is cheaper to install fiber technology on pipelines during new construction or rehabilitation rather than on pipelines that are already buried and in service.[192] TURN does not dispute that this is true, but it is at best only a partial answer to the question the Commission needs the utility to answer. If it cost $25 per mile to install fiber optics during new construction and $250 per mile to install on existing pipelines while in service, all the Commission would know is that it is less expensive in the former example. But it would <u>not</u> know whether either option is cost-effective unless and until the benefits associated with the investment are calculated. [193]

The Sempra Utilities have done no detailed economic, engineering or cost effectiveness evaluation of their proposed fiber optic program. As the Utility Workers Union of America (UWUA) described, there are other less technology- and rate base-intensive approaches to mitigating the safety concerns that the Sempra Utilities contend the

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[191] OIR 11-02-019, p. 12.

[192] Ex. SCG-06 (Rivera Direct), p. 86.

[193193] Re-calculating the estimated cost as a percentage of the project cost, as the Sempra Utilities do in their rebuttal testimony, is just a different path to the same conclusion. Even if the costs associated with these technologies represent less than 6% of the total construction costs, they might still be a poor investment of ratepayer funds if the associated benefits represent an even smaller fraction of the total costs. Ex. SCG-23 (Rivera Rebuttal), p. 19.

fiber optic program would address, such as expanding existing leak survey and patrol programs.[194] Such alternatives should be explored and compared to the proposed investment in fiber optics. As of now, the Commission lacks substantial evidence to even consider whether or not the utilities' proposal is in ratepayers' best interest.[195]

ii) Methane Detection Monitors

The Sempra Utilities' proposal to install up to 2,100 methane leak detection monitors is inadequately supported. There is a single paragraph of direct testimony that describes the gist of the proposal (with a second paragraph explaining that it is subject to change if lower-cost, mass-produced devices become available.[196] TURN's testimony referred to concerns raised in the CPSD report, in which the staff cited as sufficient the additional leak surveys performed as part of the utilities' interim measures.[197] TURN also noted CPSD's concern that the costs associated with calibrating methane detection devices has proven to be labor-intensive under the best of conditions, and the installation of such devices in open (rather than controlled) environments has resulted in false alarms.[198] To illuminate, the ongoing O&M costs associated with calibration and ongoing monitoring appear to be more than triple the costs of installing the monitors themselves.[199] Furthermore, the Sempra Utilities propose these costs to be additive to existing costs to support existing levels of leak detection activities. TURN submits that this is an

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[194] Ex. UWUA-01 (Wood Testimony), p. 10.

[195] Ex. TURN-02 (Marcus Testimony), p. 25.

[196] Ex. SCG-07 (Rivera Direct), pp. 86-87.

[197] Ex. TURN-02 (Marcus Testimony), p. 26.

[198] *Id*., p. 27.

[199] *Id*., citing Ex. SCG-10 (Reyes Direct), Table IX-<u>15</u> (misstated in TURN's testimony as Table IX-5).

insufficient basis upon which to grant the utilities' request for funding of this technology at this time.

3. Pre-1946 Pipeline "Mitigation" -- Girth welds and wrinkle bends

The Sempra Utilities propose to replace all non-piggable transmission pipeline segments installed prior to 1946, as well as all wrinkle bends in all vintages of pipeline to address the construction and fabrication methods that the utilities now characterize as "present[ing] potential construction/fabrication threats."[200] This is the most expensive single component contained within the Sempra Utilities' Proposed Case, with cost estimates of $200 million in capital in Phase 1A and $884.0 million in capital in Phase 1B.[201]

The Commission should reject the Sempra Utilities' proposal for such pre-1946 "mitigation" measures at this time. The utilities have not demonstrated that these construction techniques are jeopardizing the safety of their pipeline systems; to the contrary, in their pending GRC applications the utilities described these facilities as "stable."[202] The utilities claim that their approach makes sense even though the equipment is recognized as stable under normal operating conditions due to the threat of "permanent ground displacement."[203] If this were truly the motivation, the Sempra Utilities would have proposed a more limited approach that targeted the wrinkle bends and pre-1946

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[200] Ex. SCG-04 (Schneider Direct), p. 44; Ex. SCG-09R (Rivera Direct), p. 115.

[201] Ex. SCG-09R (Rivera Direct), Table IX-14, p. 116.

[202] Ex. TURN-02 (Marcus Testimony), p. 23, citing Data Request Response DRA-DAO-24-3(f).

[203] Ex. SCG-18 (Schneider Rebuttal), p. 25.

facilities that face such risk.[204] But the utilities propose to replace all non piggable pre-1946 segments and wrinkle bends.[205]

However, the Commission should note that the Sempra Utilities describe an alternative course of action that TURN submits makes more sense under the circumstances; a selected mitigation of a higher risk subset of wrinkle bends.[206] The utilities have not yet identified such a higher risk subset, or even the criteria that they would use to identify the segments that qualify for that subset.[207] Rather than approving a plan that presumes replacement of the maximum amount of equipment, the Commission should take a more measured approach that accounts for the fact that not all wrinkle bends or other pre-1946 equipment poses a threat.

A slower pace would have the additional benefit of increasing the chance that technology currently under development would be available to provide lower-cost options than exist today. The Sempra Utilities acknowledge that the technology is under development, but describe the tools as having limited existing capabilities and relatively limited accessibility, and predict that it will be "at least a decade before a full suite of inspection methods … is available."[208] But if the Commission were to authorize the Sempra Utilities' plan here, all of the pre-1946 pipeline segments and all of the wrinkle

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[204] It is not enough to simply label all of southern California as "earthquake country." Schneider, Sempra Utilities, 3 RT 499, ll. 3-5. Only 26.4 miles of pre-1946 pipeline segments are associated with pipelines located in areas with active faults. Ex. TURN-10, DR Response 7-6. The Alquist Priolo standards for identifying such areas with active faults are the same the utilities used in their GRC showing. Ex. DRA-16 (workpapers from GRC).

[205] Schneider, Sempra Utilities, 3 RT 498, ll. 23-26.

[206] Ex. SCG-18 (Schneider Rebuttal), p. 27.

[207] "[W]e want to work with the Commission to identify what [those] criteria would be." Schneider, Sempra Utilities, 3 RT 503, ll. 26-28.

[208] Ex. SCG-18 (Schneider Rebuttal), p. 30.

bends in pipes of all vintages would have been removed in the next ten years. Under the Sempra Utilities' proposal, the "full suite of inspection methods" would appear just after the moment when these replacements would have been completed. The Commission should instead opt for an approach that maximizes the opportunities to take advantage of emerging technology even before it reaches the "full suite" stage.

4. Enterprise Asset Management System

The Sempra Utilities seek authorization for approximately $7 million to support their investigation of developing an Enterprise Asset Management System (EAMS). The EAMS is an effort to bring "industry leading records management practices and information technology solutions" to the utilities' pipeline assets, inspection and maintenance activities, as well as O&M and system operating data.[209] But the funding sought here is not for an actual full-fledged EAMS, but rather "seed money" that the utilities would use to investigate and design the parameters of a future EAMS. As the Sempra Utilities describe it, under the proposed approach and schedule they would devote the next six to twelve months to developing the detailed architecture and design of the new system that will be the subject of a subsequent application before the Commission.

> During this phase, Enterprise Asset Management System objectives and guiding principles will be finalized; records and information management governance policies and procedures will be refined and reinforced; organizational roles and responsibilities related to records and information management will be updated; and the records and information management master data model will be updated. The output from this phase will form the basis for a proposed

[209] Ex. SCG-07 (Rivera Direct), p. 92.

> Enterprise Asset Management System to be submitted for approval by the Commission in a subsequent filing.[210]

As described in the utilities' direct testimony, the EAMS proposal seems to have dual purposes. On the one hand, the utilities described the proposal as necessary in order to bring their "supporting data (meta data) and documents" for their transmission pipelines into compliance with the directive in D.11-06-017 to have its records "readily available" or "readily accessible."[211] Having asset information "readily available" is already a requirement of the Transmission Integrity Management Program.[212] Thus to at least some degree the EAMS proposal is targeted at remedying a current deficient practice. On the other hand, the Sempra Utilities claim that their existing applications and data bases are adequate to meet existing requirements, and EAMS is targeted at dealing with "new and emerging targets."[213] At this early stage of project development, with the underlying principles not yet finalized, it is hard to know which characterization is the accurate one, or whether each is accurate as applied to different elements of what EAMS may turn out to be.

TURN's testimony presented alternative views of how the Commission should treat the EAMS project proposal. To the extent the project seeks to remedy the Sempra Utilities' inability to readily locate essential testing records in response to Resolution L-410, the cost

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[210] *Id.*, p. 94. It is worth noting that this request for immediate approval of only initial efforts to develop the EAMS proposal, followed by a request for full development once the results of the initial efforts are known is generally consistent with the alternative proposal TURN recommends for the broader PSEP plan.

[211] *Id.*, p. 90; Ex. SCG-23 (Rivera Rebuttal Testimony), p. 23. The decision uses the term "readily available." D.11-06-017, pp. 19-20. The Sempra Utilities use "readily available" in their direct testimony, and "readily accessible" in their rebuttal testimony, seemingly interchangeably.

[212] Rivera, Sempra Utilities, 7 RT 1294, ll. 2-15.

[213] Ex. SCG-23 (Rivera Rebuttal), pp. 21, 23.

should not be borne by ratepayers.[214] Similarly, the creation of a "governance blueprint" to identify, among other things, master data record sources, data ownership, and data management processes and accountability within the utilities,[215] is work that the Sempra Utilities should have completed long ago.[216]

TURN also recognized that the Enterprise Asset Management System project has the potential to produce ratepayer benefits that might warrant rate recovery of costs not associated with remediating past deficiencies and bringing past practices to current standards.[217]

Therefore, TURN proposes the following approach for the EAMS project in this proceeding. The Commission should authorize the Sempra Utilities to track the related costs in their Pipeline Safety and Reliability Memorandum Accounts, subject to subsequent reasonableness review in the next general rate case or in another proceeding the Commission designates for such review. In addition to cost-effectiveness and other more traditional reasonableness review issues, the Sempra Utilities would need to demonstrate that the EAMS effort is incremental to the effort necessary to meet existing prudent record-keeping standards.[218]

The Commission should also direct the utilities to: prioritize use of "off-the-shelf" data management tools rather than inventing Sempra-specific tools; seek out EAMS packages that have longer asset lives than the typical five-year asset life for software; ensure that any EAMS proposal would be easily integrated with other geographic

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[214] Ex. TURN-01 (Long Testimony), p. 24.

[215] Ex. SCG-07 (Rivera Direct Testimony), p. 92.

[216] Ex. TURN-01 (Long Testimony), p. 24.

[217] Ex. TURN-02 (Marcus Testimony), p. 28.

[218] Ex. TURN-01 (Long Testimony), p. 24.

information system (GIS) assets owned and used by the utilities; and ensure the EAMS proposal would complement other asset management systems and programs such as the Company's Operational Excellence (OpEx) programs. Finally, the Commission needs to make clear that any authorization of the initial EAMS proposal at this time is not binding or predictive of the outcome for any final EAMS proposal the Sempra Utilities may present in the future. The expectation should be that any future proposal for a final version of EAMS would be fully supported such that it can be fully vetted for reasonableness based on its stand-alone merits.[219]

The Sempra Utilities' rebuttal indicated the utilities' disagreement with TURN's suggestion that the Enterprise Asset Management System is proposed "to remediate inadequate governance, processes and systems … or bring systems up to standards that should already have been met relating to accessibility of data and data governance." To the contrary, they insist, "SoCalGas and SDG&E current processes and systems meet regulatory requirements and applicable industry standards."[220] The problem with the rebuttal testimony is that it is contradicted by the very first paragraph of the relevant chapter of their direct testimony:

> While the data required to operate and maintain the SoCalGas/SDG&E natural gas transmission pipeline system are currently readily available, supporting data (meta data) and documents, which are often paper records, are not readily available. Existing systems for storing and accessing data, which have evolved over time, are not integrated and are often in different formats. To have all such data, and supporting data, integrated and readily available, various data repositories, including maintenance and inspection systems, geographical information systems, purchasing systems, and paper records must be connected, and

[219] Ex. TURN-02 (Marcus Testimony), p. 28.

[220] Ex. SCG-23 (Rivera Rebuttal Testimony), p. 24.

> interrelated. Accordingly, SoCalGas and SDG&E propose to design and develop a comprehensive Enterprise Asset Management System as an integral part of their Pipeline Safety Enhancement Plan.[221]

The Sempra Utilities expressly did not raise any objection to the TURN recommendations regarding specific direction the Commission should adopt regarding EAMS.[222]

V. REASONABLENESS OF COST ESTIMATES

In D.11-06-017, the Commission recognized

> To perform our Constitutional and statutory duties, we must have … comprehensive analysis of the advantages and disadvantages of potential actions.[223]

A key part of that "comprehensive analysis" is the assessment of the reasonableness of cost estimates associated with the options for "potential actions." The record evidence in this proceeding leads to only one conclusion: the cost estimates put forward by the Sempra Utilities to date are too rough and too preliminary in nature to permit the Commission to adopt a reasonable revenue requirement in a manner consistent with its Constitutional and statutory duties.

The Sempra Utilities themselves neatly summarized the underlying problems with their proposal:

> The estimates in our workpapers represent best available cost projections considering the nature and extent of projects that needed to be estimated for the PSEP, and the short timeframe available to develop them. SoCalGas and SDG&E acknowledge that these estimates are necessarily preliminary and often somewhat conceptual in nature. However, these estimates, when combined with the risk-based allowances provided by established contingencies, provide a reasonable projection of costs that will ultimately be incurred by

[221] Ex. SCG-7 (Rivera Direct Testimony), p. 90.

[222] Ex. SCG-23 (Rivera Rebuttal Testimony), p. 22.

[223] D.11-06-017, p. 17.

> SoCalGas and SDG&E to achieve the Commission's commitment to improve the safety of natural gas transmission pipelines in California.[224]

Each of these three sentences highlights a separate flaw in the utilities' showing. Regardless of whether the cost estimates were ever the "best available," that label does not mean the estimates are an appropriate or sufficient basis for setting rates. Estimates that are "preliminary" and "conceptual" are problematic, to say the least, when it comes to setting cost-of-service rates that are "just and reasonable." Finally, if the way to transform these preliminary and conceptual estimates into "a reasonable projection of costs" is an across-the-board increase of 20-30% to reflect "contingencies," the Commission must decline the invitation to set rates based on those estimates and instead explore alternative approaches.

A. The Issue For The Commission Is Whether The Sempra Utility Cost Estimates Are Sufficiently Developed To Support A Finding that Rates Based On Those Estimates Would Be "Just and Reasonable," Not Whether the Estimates Ever Warranted the Label of "Best Available."

In D.11-06-017, the Commission assigned a daunting task to the Sempra Utilities – prepare an "implementation plan" that includes, among other things, "specific rate base and expense amounts for each year proposed to be included in regulated revenue requirement."[225] In a general rate case, the utilities devote many, many months to preparing revenue requirement proposals for typical and ongoing utility operations; here, the Commission gave the utilities two months for revenue requirement proposals to support a unique and unprecedented effort. Thus it is not surprising to see the Sempra Utilities refer to the amounts included in their PSEP as "best available cost projections

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[224] Ex. SCG-21 (Buczkowski Rebuttal Testimony), pp. 1-2.

[225] D.11-06-017, Conclusion of Law 7.

considering the nature and extent of projects that needed to be estimated for the PSEP, and the short timeframe available to develop them."[226]

TURN does not dispute that the figures put forward in the utilities' showing may represent the "best available" estimates from when the utilities prepared their PSEP proposal for unveiling in August 2011.[227] But "best available" is not synonymous with "sufficient for ratesetting purposes;" indeed, the record developed in this proceeding contains ample evidence that "best available" cost estimates can also be "not ready for prime time" for ratesetting purposes.

Furthermore, the Commission needs to consider that if the cost estimates prepared for the PSEP unveiled in August 2011 still represent "the best available cost projections" today, it is only because the Sempra Utilities have not updated those August 2011 estimates to any significant degree.[228] TURN makes this point as an observation, rather than as a criticism of the utilities for failing to make any such update. TURN concedes that there was no clear obligation for the utilities to update their estimates once it became clear to them that they would not get a decision approving some version of a PSEP within the timeframe they seem to have originally anticipated. However, the fact of the matter is that the quality of the estimates first presented in August 2011 based on the utilities' best efforts during the two months after D.11-07-016 issued had not improved with the passage of time once the evidentiary hearings convened in August 2012.

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[226] Ex. SCG-21 (Buczkowski Rebuttal Testimony), p. 1.

[227] The utilities concede that the initial estimates from August 2011 have not been substantially refined or updated in the year since then. Buczkowski, Sempra Utilities, 5 RT 855, ll. 6-12.

[228] Buczkowski, 5 RT 855, ll. 1-12. While the Sempra Utilities made an amended PSEP filing in December 2011, it is not clear that the cost estimates changed in any material way between the original and amended versions of the plan. Rivera, Sempra Utilities, 7 RT 1300, ll. 12-17.

In sum, the Commission should assign little or no value to the "best available" label as applied to the utility-developed cost estimates. Whether or not that is true is of limited (if any) relevance to the goal of setting a reasonable revenue requirement going forward.

B. The Sempra Utilities' Cost Estimates May Be The Most Reasonable "Class 5 Or Slightly Better" Figures That Could Have Been Developed Under the Circumstances; The Commission Must Still Find That Such Estimates Are Too Preliminary And Conceptual To Be The Basis For Adopting A Revenue Requirement Forecast.

The Sempra Utilities describe their own estimates as ranking "Class 5 or slightly better" on a scale of one to five.[229] They also acknowledge that such rough estimates need further development before serving as the basis for a budget:

> While additional project definition and analysis is typically required to refine the estimates to support a more detailed program budget authorization, the class 5 estimates provide a valuable basis to move forward with a major capital program.[230]

"A valuable basis to move forward" is a far cry from "an appropriate basis for adopting a forecast for ratesetting purposes."[231] The AACE categorization is driven largely by the level of project definition; a Class 1 estimate applies where a project's developer knows 50% to 100% the project's definition and scope, while a Class 5 estimate is based on an understanding of 0% to 2% of the definition and scope, and a Class 4 estimate has a definition and scope of 1-15%.[232]

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[229] The Sempra Utilities' "Class 5 or slightly better" characterization is based on a "recommended practice" produced by the Association for the Advancement of Cost Engineering (AACE).

[230] Ex. SCG-21 (Buczkowski Rebuttal), p. 4.

[231] Under the circumstances, the "move forward" would be in the direction of more refined project description and cost estimates that might serve as the basis for budget authorization and funding.

[232] Ex. TURN-02 (Marcus Testimony), p. 5, citing AACE Recommended Practice 17R-97 (Ex. DRA-19). The Sempra Utilities' testimony referred to Recommended Practice 18R-97 (Ex. DRA-18), a version more specific to process industries. The "project definition" figures for Class 5 and

By the utilities' own description, the vast majority of the cost estimates are "preliminary and were developed based on minimal engineering, operational planning and project execution planning,"[233] and are "often conceptual in nature."[234] The AACE Standard Practice alternative descriptors for such "Class 5" estimates, including "ballpark, blue sky, [and] seat-of-pants."[235]

Whether the Commission adopts the more genteel labels preferred by the utilities or the plain English versions offered by the AACE itself, the conclusion is the same. Given the Commission's statutory duty to ensure rates that are "just and reasonable" and the evidentiary record developed in this proceeding, the Commission cannot rely on the Sempra Utilities' cost estimates to set rates on a forecast basis.[236]

C. The Broad Application of Contingency Adjustments Of 20-30% Further Highlights The Inappropriateness Of Relying On Preliminary and Conceptual Cost Estimates.

The word "contingency" appears only once in the Sempra Utilities' direct testimony, in the last entry on the list of "estimating methodology and assumptions" included as Appendix D:

Class 4 in that version are substantially the same as those set forth for broader application in 18R-97.

[233] Ex. SCG-09R (Rivera Direct Testimony), p. 103. While the direct testimony did not in any way indicate that any of the utility-developed costs did not fit within this description, the rebuttal testimony claimed that the "caveats" do not apply to the Valve Enhancement Plan. Ex. SCG-23 (Rivera Rebuttal Testimony), p. 10.

[234] Ex. SCG-21 (Buczkowski Rebuttal Testimony), p. 2.

[235] Ex. TURN-02 (Marcus Testimony), p. 5; Ex. DRA-18 (Recommended Practice No. 18R-97), p. 5 of 10.

[236] According to the utilities' witness, "with the right usage a Class 5 or Class 4 estimate can be used for project capital funding." Buczkowski, 4 RT 582, ll. 1-3. TURN submits that the utilities are free to test this assertion on a project funded by shareholders, but so long as any substantial portion of the PSEP costs are intended to be collected from regulated rates, the Commission must reject such a cavalier approach.

> This estimate is based on preliminary engineering only and includes several assumptions. As a result, the estimate includes a 20% or 30% contingency depending on total estimated cost. Once detailed engineering and design are completed a revised estimate can be generated to reflect the actual scope of project and associated permit conditions.[237]

In the face of challenges to the 20-30% contingency amounts included in their cost estimates, the Sempra Utilities' rebuttal testimony reiterated data request responses that had "defined contingency as an amount 'covering costs that may result from incomplete design, unforeseen and unpredictable conditions, or uncertainties within the defined project scope.'"[238] The utilities also cited an AACE definition of contingency that states, in part, "Contingency covers inadequacies in complete project scope definition, estimating methods, and estimating data."[239]

It may well be that in the early stages of project development, when designs are incomplete and even the project scope is uncertain, using a contingency factor to develop cost estimates is a reasonable step that is taken as a matter of course. But where, as here, the question is whether a cost estimate is appropriate for inclusion on a forecast basis in cost-based rates, a different approach is required. Rather than use a higher contingency factor to adjust the estimates upward in order to reflect the incomplete design or the "inadequacies in complete project scope definition, estimating methods, and estimating data," the Commission must pursue cost estimates that do not suffer from these maladies. That is, instead of adopting estimates that are based on preliminary engineering and numerous assumptions and, therefore, include contingency factors of 20% or even 30%,

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[237] Ex. SCG-09 (Rivera Direct Testimony), Appendix D, p. D-3 [emphasis added].

[238] Ex. SCG-21 (Buczkowski Rebuttal Testimony), p. 10, quoting an unspecified data request response.

[239] *Id.*, quoting AACE Recommended Practice 34R-05 (Ex. DRA-22).

the Commission should defer adopting a forecast-based revenue requirement until it has the benefit of the more detailed engineering and design that, according to the utilities, would permit lower contingency factors as part of updated cost estimates.

The Commission has previously rejected higher contingency amounts made necessary due to the preliminary nature of the underlying cost estimates.

> Because SCE's cost estimates remain at a very preliminary stage, we find no value in simply increasing this number by an arbitrary contingency rate…we do not find SCE's [Rough Order of Magnitude] cost estimates sufficiently reliable to make a determination that a contingency is warranted.[240]

Here, it is not enough to simply reduce the overall estimates by replacing the requested contingency factors with a lower amount.[241] The proposal to use contingency factors of 20% or 30% is a symptom of the broader problem. If the cost estimates were appropriately developed and adequately supported, and reflected a more nearly complete project design, there would be no need for a 20-30% contingency factor.

D. The Commission Should Take This Opportunity To Address Generic Forecasting Issues To Reduce Potential Disputes When The Sempra Utilities Seek Approval Of PSEP Cost Estimates In The Future.

There are a number of somewhat generic ratemaking issues the Commission may be able to address based on the record developed in this proceeding, even as it defers action for most of the Sempra Utilities' proposal pending presentation of more robust proposals reflecting more complete engineering and planning. TURN has identified two at this time – the appropriate level of AFUDC for purposes of this application, and the

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[240] D.09-03-025 (SCE Test Year 2009 GRC), p. 247, *as cited in* Ex. TURN-02 (Marcus Testimony), p. 7.

[241] Should the Commission choose to adopt cost forecasts for ratemaking purposes in this proceeding, however, it should reject the Sempra Utilities' requested contingency factors in favor of a relatively low AFUDC rate (Ex. TURN-02 (Marcus Testimony), p. 8).

inappropriateness of including a loader for incentive compensation plan costs. Addressing these issues here will permit the adopted outcomes to serve as additional guidelines for the project-specific showing to be made going forward.[242]

1. The AFUDC Rate Should Be Set At A Level More Consistent With Current Short-Term Debt Costs.

The Sempra Utilities' direct testimony mentions Allowance for Funds Used During Construction (AFUDC) only once, in the description of the capital costs assumed to be recovered through depreciation over the book-life of the assets.[243] TURN did not locate any mention of AFUDC in the utilities' workpapers.

TURN's testimony noted that the Sempra Utilities' cost estimates did not explicitly identify the proposed AFUDC rate. TURN proposed using an AFUDC rate of 2% for small jobs and 5% for larger ones, and noted that given only a limited amount of AFUDC was likely to accrue given the pattern of costs under the utilities' proposal.[244] In their rebuttal testimony, the Sempra Utilities objected to this approach, arguing that the appropriate AFUDC rate is the full authorized rate of return for each utility (8.68% for SoCalGas and 8.40% for SDG&E).[245]

The opening brief of the Utility Workers Union of America (UWUA) address the AFUDC issue at some length, and presents an analysis that the Commission should find persuasive. As the UWUA brief explains, AFUDC represents the capitalized cost of financing construction activity before a project achieves "used and useful" status and is

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[242] Ex. TURN-01 (Long Testimony), p. 10.

[243] Ex. SCG-10 (Reyes Direct Testimony), p. 123.

[244] Ex. TURN-02 (Marcus Testimony), p. 8.

[245] Ex. SCG-26 (Reyes Rebuttal Testimony), p. 10.

added to rate base.[246] The point is to achieve "adequate compensation for [the utility's] advance commitment of capital."[247] The formula prescribed by FERC for purposes of determining the <u>maximum</u> allowable AFUDC rate assumes that short-term debt is the first source of funds for construction.[248] The authorized rate of return, on the other hand, relies on a weighted average of the cost of <u>long-term</u> debt and the authorized return on equity. In other words, the Sempra Utilities' approach to AFUDC assumes that <u>none</u> of the funds for construction comes from short-term debt. This is an unreasonable assumption. There is no evidence that the Sempra Utilities do not have sufficient access to short-term debt markets, nor is there any evidence that the Sempra Utilities would not rely at least in part on short-term debt to finance construction activity. Given the current historically low short-term debt levels,[249] it would be foolish for the utilities to not take full advantage of this almost no-cost source of financing.[250]

TURN is not proposing here that the Commission adopt a modified AFUDC rate for any purpose other than the spending associated with the PSEP. However, for purposes of the PSEP the Commission should adopt the TURN-recommended figures of 2% for small jobs (that is, jobs below the $2 million direct cost level) and 5% for relatively larger jobs (above the $2 million direct cost level) as a figure more consistent with the reasonable

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[246] UWUA Opening Brief, p. 34.

[247] *Id.*, quoting Bonbright, *Principles of Public Utility Rates*.

[248] *Id.,* p. 35, quoting Bonbright, *Principles of Public Utility Rates*.

[249] *Id.*, p. 37, citing data available on the web site of the U.S. Department of the Treasury.

[250] *Id.*, p. 38. Setting the AFUDC rate at the same level as the authorized rate of return, however, presumes the utilities are not using this near-zero cost of funding at all. And as UWUA notes, setting the AFUDC rate at a level higher than the level of costs the utilities are likely to actually incur to finance PSEP-related construction creates an opportunity for a windfall for the utilities.

assumption that the Sempra Utilities should and will rely at least in part on short-term financing for construction costs associated with the PSEP.

2. Given the Events Leading Up to the PSEP, The Commission Should Direct The Utilities To Exclude The Incentive Compensation Loader From All PSEP Cost Estimates and Revenue Requirement Calculations.

The Sempra Utilities propose to apply an 18.17% incentive compensation plan (ICP) overhead loader to SoCalGas' management and associated direct labor costs, and a 17.79% incentive compensation plan overhead loader to SDG&E's management and other direct labor costs.[251] The Commission should reject the Sempra Utilities' proposal for rate recovery of such costs as inappropriate given the circumstances surrounding the PSEP.

Incentive compensation plans tend to reward utility management and employees for meeting specific financial goals that contribute to the shareholders' bottom line. Whether or not it is appropriate to have ratepayers fund these types of incentive compensation plans in the normal course of business, doing so for ICP costs associated with the pipeline safety enhancement plan is clearly not in the ratepayers' best interests.

As proposed by the Sempra Utilities, the substantial majority of PSEP costs are capital expenditures and will end up in the rate base of one or the other of the utilities. Essentially PSEP doubles SoCalGas's rate base growth over the next four years.[252] The utilities will have an opportunity to earn their authorized rate of return on this PSEP-related rate base. The Commission should deem this opportunity for increased earnings

[251] Ex. SCG-10 (Reyes Direct Testimony), p. 122.

[252] Ex. TURN-02 (Marcus Testimony), pp. 3,8.

due to the PSEP to be a sufficient financial incentive such that an additional rate-funded incentive in the form of an ICP loader is unnecessary.[253]

In addition, to the extent any of the amounts added to rate base are related to the portions of the PSEP that are made necessary due to past management mistakes or omissions (such as failing to adequately document and maintain historic records of pipeline tests and inspections), it would heap insult upon injury to require ratepayers to also bear costs associated with the incentive compensation plan.[254]

The Sempra Utilities objected to this proposal largely on the basis that they need to attract and retained well-qualified employees in order to make the PSEP effort a success, and the incentive compensation plan is important element of that process.[255] TURN's recommendation does not prevent the Sempra Utilities from offering an incentive compensation plan to employees working on developing or implementing the PSEP. Rather, TURN's recommendation would have those costs excluded from rates. The utilities can still choose to make incentive compensation a part of the compensation package offered to any employee, but under the unusual and largely unique circumstances under which the PSEP arises, the costs of such packages should not be borne by ratepayers.

VI. ALTERNATIVES TO REPLACEMENT OR PRESSURE TESTING

The Sempra Utilities seek funding authorization based on the presumption that pipeline segments that fall within the PSEP will need to be either pressure-tested or replaced. However, their testimony describes a number of opportunities for alternatives

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[253] *Id.*, p. 8.

[254] *Id.*

[255] Ex. SCG-26 (Reyes Rebuttal Testimony), pp. 12-13.

that might be less disruptive and substantially less expensive than either pressure-testing or replacement. For example:

- New technology (some of it funded by ratepayers through SoCalGas's research and development program) shows promise for making lines that are not "piggable" today become piggable in the future.[256] If these efforts bear fruit, the costs for achieving system-wide inspections could decline substantially.

- The single largest cost component of the PSEP as proposed is the elimination of wrinkle bends and pre-1946 construction. The Sempra Utilities rebuttal testimony identifies an alternative to full funding for this effort; "selected mitigation of a higher risk subset of wrinkle bends present on affected pipelines."[257] Adopting such a "selective approach" would produce substantial cost reductions and, by extension, reduced rate impacts.

One of the advantages of the alternative approach that TURN recommends for broader application to the Sempra Utilities' PSEP is that it would enable Commission flexibility and thereby permit ongoing consideration of the evolving technologies and strategies for achieving the Commission's PSEP goals. Under the Sempra Utilities' approach, the Commission is asked to adopt priorities and funding levels now based on a binary choice between replacement and pressure-testing, without any clear path to future consideration of alternatives that may emerge as the state of technology changes. Deferring action on the pipeline replacement projects, as TURN proposes, would permit the Commission to include in its future review an assessment of the then-current state of technology and ensure a more meaningful opportunity to adopt cost forecasts that reflect the actual available options, not just those identified some years before.

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[256] Ex. TURN-02 (Marcus Testimony), p. 21.

[257] Ex. SCG-18 (Schneider Rebuttal), p. 27.

VII. REVENUE REQUIREMENTS

A. Proposed Revenue Requirements

1. The Commission Should Reject The Proposal For A Separate Attrition Mechanism.

The Sempra Utilities' direct testimony proposed that the "authorized Pipeline Safety Enhancement Plan revenue requirement and post-test year spending requests [] have a separate attrition mechanism," in addition to the other regulatory accounting treatment described in the testimony.[258] But when asked to further explain this proposal, the utilities' witness seemed to suggest that the separate attrition mechanism would not come into play until the next regularly-scheduled General Rate Case (2016 by the utilities' calculation).[259]

The Commission should reject without prejudice the proposal for a separate PSEP-specific attrition mechanism. TURN found no indication of such a separate attrition mechanism for any other discrete portion of the utilities' operations in the settlement of the test year 2008 GRC for the Sempra Utilities, or in the decision adopting that settlement.[260] If there is a good reason for adopting such a mechanism, the Sempra Utilities will have an opportunity to make such a showing in the 2016 GRC. But where, as here, no clear explanation of what the utilities are seeking, much less any showing in support of the request, the Commission does not have sufficient record support for adoption of the utility request, even if it understood the utility's request.

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[258] Ex. SCG-10 (Reyes Direct), p. 121.

[259] Reyes, Sempra Utilities, 8 RT 1488, ll. 7-19.

[260] D.08-07-046, issued in A.06-12-009.

B. Intervenor Proposals Relating to Revenue Requirements

The Commission should authorize a revenue requirement consistent with the alternative proposal described in this brief. That is, it should limit any authorized revenue requirement at this time to amounts associated with pressure-testing projects the Sempra Utilities have identified for commencement during the first year of work once the PSEP is approved, with the actual spending subject to after-the-fact reasonableness review.[261]

In early 2012 the utilities described how their initial analysis "identified some projects that have a greater likelihood of moving through the engineering/design, permitting, and construction lifecycle quickly in order to commence and potentially complete field construction for some projects during the one-year period."[262] For SoCalGas, the first twenty or so of these projects list O&M costs, signifying that each of these projects involves pressure-testing rather than replacement. SDG&E does not list any O&M costs on its priority list.[263] While the criteria and cost estimate information supporting the pressure testing projects suffer from the same flaws and shortcomings as do the replacement projects, the vast differential in the per-unit costs associated with the two options makes pressure testing the less financially consequential of the two.[264] The after-the-fact reasonableness review mitigates the risk that the "guesstimate" nature of the cost estimates will impact the amounts ultimately collected in rates.

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[261] Ex. TURN-01 (Long Testimony), pp. 11-12.

[262] Comments of SCG and SDG&E in Response to Assigned Commissioner's Rulings and Supplement to Request for Memorandum Account, filed January 13, 2012, R.11-02-019, p. 7 (as quoted in Ex. TURN-01 (Long Testimony), p. 11).

[263] *Id*., Attachment A, pp. 4, 7. The Attachment is in the record of this proceeding as Ex. SCGC-03.

[264] Ex. TURN-01 (Long Testimony), p. 11.

Under TURN's recommended alternative approach, the Commission will need to later address revenue requirements associated with the other more numerous projects, when those matters are brought to the Commission either for cost forecast approval in a expedited application process (such as that SCGC proposed for pipeline replacement projects) or for an after-the-fact reasonableness review. Such an approach is necessary in order to ensure that only reasonable costs, whether found reasonable on a forecast or recorded basis, are deemed eligible for rate recovery and included in authorized revenue requirements.

VIII. RATEMAKING TREATMENT FOR RECOVERY OF PHASE 1A COSTS

The Sempra Utilities' ratemaking proposal is slightly better-developed than their cost forecasts or project definitions, only because the central premise underlying the proposal is fully-developed: the utilities would recover all incurred costs, regardless. That is, full recovery regardless of whether those costs are consistent with any forecast the utilities have presented to date. Perhaps most remarkably, the utilities ask the Commission to bypass any reasonableness review in favor of a utility-performed review:

> As long as costs incurred within the PSEP have been approved by the Commission, there should be no need for after-the-fact reasonableness review of the costs recorded in the PSEP Cost Recovery Accounts or for expedited applications for pipeline replacement projects. <u>SoCalGas and SDG&E will review PSEP costs that are recorded in the PSEP Cost Recovery Accounts to ensure that these costs are truly incremental and not otherwise recovered in base transportation rates or subject to any other Commission-approved balancing account mechanism</u>.[265]

[265] *Id*., p. 6 [emphasis added].

But as the utilities' testimony made amply clear (and as TURN discussed more fully in Section VIII, above), the only "costs incurred within the PSEP" that can be "approved by the Commission" are, to adopt the AACE's parlance, "guesstimates" at best:

> Cost estimates are preliminary and were developed based on minimal engineering, operational planning, and project execution planning…. [T]he Phase 1A schedule is very aggressive, and subject to potential execution challenges that could impact costs.[266]

Indeed, it is not clear to TURN why the utilities went through the exercise of preparing and presenting cost forecasts at all, since the estimates are so preliminary and, under the proposed ratemaking treatment, are largely illustrative and of virtually no consequence to the amounts that would ultimately be collected in rates.

The Commission must reject the ratemaking treatment proposed by the Sempra Utilities. There is no opportunity at this time to meaningfully review even the cost forecasts as presented in the testimony, given the utilities' ongoing and consistent acknowledgment that the cost estimates are "preliminary and were developed based on minimal engineering, operational planning, and project execution planning."[267] Without such an opportunity for meaningful review, there is no basis for a Commission finding of reasonableness at this time. And absent such a finding of reasonableness, there is no basis for rate recovery of the forecast amount of costs, much less the incurred amount of costs. Rather than embrace an approach that would permit such unfettered cost recovery under such conditions, the Commission should adopt an approach that would more appropriately balance the desire to move forward (even in the face of uncertain work plans and cost

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[266] Ex. SCG-10 (Reyes Direct), p. 103 (emphasis added).

[267] Ex. TURN-01 (Long Testimony), p. 6, citing Ex. SCG-09 (Rivera Direct), p. 103.

estimates) with the obligation to ensure only just and reasonable costs make their way into rates.

A. PSEP Cost Recovery Account

The Sempra Utilities propose to create a "Pipeline Safety Enhancement Plan Cost Recovery Account" for each utility.[268] The utilities' rebuttal testimony made clear that they seek a two-way balancing account structure for the proposed accounts.[269] And while the direct testimony appears to be silent on the question of whether the Commission would perform after-the-fact reasonableness review of the costs recorded in this account or the activities associated with those costs, the rebuttal testimony addressed the question very directly: The only reasonableness review will be conducted by the utilities, and then only consider whether the recorded costs are "incremental" to other authorized costs.[270]

The utilities assert that the two-way balancing account "ensures that ratepayers pay for the <u>reasonable</u> costs of SoCalGas and SDG&E's PSEP, and that all parties are trued-up in a timely manner for any cost/revenue differences."[271] But the costs recorded in the PSEP Cost Recovery Account would never be reviewed for reasonableness; the two-way mechanism is intended to ensure that ratepayers pay for <u>all</u> the recorded costs.[272] And the notion that the two-way balancing account is necessary to ensure timely true-ups was never

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[268] The direct testimony never labeled this a "balancing account," but rather described them as "interest bearing accounts that are recorded on SoCalGas' and SDG&E's respective financial statements." *Id.*, p. 126. It seems that the reference to "interest bearing accounts" recorded on the utilities' respective financial statements means nothing more than either typical balancing or memorandum account treatment. Reyes, Sempra Utilities, 9 RT 1494, ll. 12-19.

[269] Ex. SCG-26 (Reyes Rebuttal), p. 2.

[270] *Id.*, p. 6.

[271] *Id.*, p. 2 [emphasis added].

[272] Reyes, Sempra Utilities, 9 RT 1506, ll. 9-15.

explained; timely true-ups can be as easily achieved with memorandum accounts or with one-way balancing accounts. The Sempra Utilities raised the specter of "large PSEP-related undercollections that could have significant rate impact to customers,"[273] but had not done the analysis that they concede would be required to assess the level of undercollections that their management would deem "huge" or a threat to potentially cause "rate shock."[274]

The utilities have failed to demonstrate the reasonableness of their proposed two-way balancing account. The Commission should reject that proposal in favor of a ratemaking mechanism that creates an opportunity for rate recovery of reasonable costs associated with reasonable projects.

B. Recovery of Authorized Phase 1A Costs

TURN submits that the rate recovery of authorized Phase 1A costs is to a large extent inextricably tied to the authorized revenue requirement for those costs, an issue addressed in Section VII, above. TURN's understanding is that other rate recovery issues were assigned to the TCAP phase of this proceeding. If other parties address rate recovery issues in their opening briefs, TURN may respond to those arguments in our reply brief.

C. Rate Recovery of Costs Recorded in PSEP Memorandum Account

The Commission should deny the Sempra Utilities' request for rate recovery of costs recorded in the Pipeline Safety and Reliability Memorandum Account (PSRMA). As TURN explained in more detail in the discussion of this memorandum account in the

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[273] Ex. SCG-26 (Reyes Rebuttal), p. 4.

[274] Reyes, Sempra Utilities, 5 RT 1503, ll. 2-13.

"Base Case" section of this brief (Section IV.C, above), rate recovery of the memorandum account's balance would suffer from the following flaws:

- To the extent costs were recorded before the Commission approved the memorandum account, rate recovery would constitute retroactive ratemaking;
- The Sempra Utilities have not demonstrated that these costs are reasonable, rather than resulting from their own imprudent record-keeping practices; and
- The utilities have not presented any evidence that would demonstrate the reasonableness of the costs incurred due to the records search effort.

For the same reasons TURN urges the Commission to keep the Memorandum Account costs out of the "Base Case," the Commission should deny rate recovery of those costs at this time.

D. Expedited Advice Letter for Proposed Adjustments to PSEP Funding

In the years following the initial implementation of the PSEP Cost Recovery Accounts, the Sempra Utilities propose a cost true-up through "expedited" advice letters. The true-up would incorporate the forecasted year-end balances in the PSEP Cost Recovery Accounts, plus the forecasted revenue requirements for the upcoming year. In this way, the proposed ratemaking appears to ensure rate recovery of whatever amount is spent and recorded in the PSEP Cost Recovery Account, even if that amount is different than the forecasts approved by the Commission.

The annual PSEP Cost Recovery Account advice letter would also include "any adjustments to the overall level of Pipeline Safety Enhancement Plan funding requirements previously approved," along with an "explanation for changes from the original revenue requirements." In this way, the Sempra Utilities seem to propose that the entire review of any such "adjustments" or "changes" would occur through the advice letter process. Finally, the annual PSEP Cost Recovery Account advice letter would include "any additional revenue requirement associated with the Enterprise Asset Management System or the expansion of the Pipeline Safety Enhancement Plan for pipeline safety enhancement activities not covered by this filing that may subsequently be adopted by the Commission."[275]

In short, the Sempra Utilities ask the Commission to permit them to seek rate relief through an advice letter that goes far beyond the constraints the agency has set for advice letters.[276] And they ask that they obtain the requested rate relief on an accelerated timeline under which intervenors and the Commission would have to review and analyze the advice letter and any supporting documents in less time than General Order 96 provides for the far more innocuous tariff changes typically sought through the advice letter process.

At some point in the future, the Commission might have enough experience with Sempra Utilities' PSEP projects to consider their review so routine as to warrant incorporating advice letters into the review process. However, at this juncture such an approach is premature at best. Therefore the Sempra Utilities' proposal should be rejected.

E. Annual PSEP Update Report

IX. ADDITIONAL INTERVENOR PROPOSALS

A. Proposed Notice Requirement

B. Local Transmission Interruption Credit Proposal

C. BTS Reservation Charge Credit Proposal

D. UWUA O&M Proposals

E. Treatment of Robotics Royalties

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[275] *Id.*, pp. 7-8, quoting Ex. SCG-12 (Reyes Direct), p. 126.

[276] TURN addressed this point more fully in Section IV.B.3, above, and incorporates that discussion by reference here.

Emerging technologies create at least the possibility that pipelines that are currently determined to be "non-piggable" might be able to be addressed in the near future through less costly means than replacement or pressure tests. The Sempra Utilities stand to benefit financially from the pursuit of such emerging technologies as it will collect royalty amounts. SoCalGas, through its ratepayer-funded participation in NYSEARCH (a member-supported research and development division of the Northeast Gas Association (NGA)), is entitled to 12.3% of the revenues from the commercial development of such technologies.[277]

The full amount of those royalty revenues from the commercialization of the robotic in-line inspection technology should be recorded as an offset to any PSEP costs that are eventually authorized here. TURN submits that such an outcome is reasonable and fair under the circumstances. The growing interest in such robotic in-line inspection technologies is in large part attributable to the San Bruno disaster and the regulatory, legislative and public response thereto. The Sempra PSEP itself, with its price tag for direct costs in excess of $1.7 billion, will be a strong driver of demand for such technologies. The Commission should find that, under the circumstances here, the equitable approach would have all royalty revenues flow to offset the PSEP costs that are ultimately included in rates.

The Sempra Utilities oppose this proposal, and instead call for no different treatment of these royalties. Under their approach, once the initial cost of the technology investment is recouped, the net revenues from royalties would be shared 60/40 between

[277] Ex. TURN-02 (Marcus Testimony), p. 22.

ratepayers and shareholders, respectively.[278] While the utilities describe this as "reducing ratepayer costs dollar for dollar," this is true only for the ratepayer costs associated with the new technology, not the PSEP-related costs. If the heightened interest in pipeline safety and maintenance resulting from incidents such as the San Bruno catastrophe produces an increased demand for the new technologies that have been the subject of ratepayer-funded investment, the utilities should be allowed to reap the windfall benefits.

TURN submits that the Commission should recognize that the exception we propose to the established treatment of these revenues is appropriate under the circumstances. The Sempra Utilities stand to benefit financially from the increased rate base that will result from the Commission's approval of even the most limited PSEP proposal, from the opportunity to earn the authorized rate of return on that incremental investment.[279] TURN recognizes that the offset of 100% of the net royalty payments rather than 60% is likely to make a very small dent in the total PSEP costs assigned to ratepayers. But the Commission should adopt TURN's recommendation as an appropriate (albeit small) effort to reduce the total cost impact to ratepayers and to limit the degree to which the Sempra Utilities would unduly benefit from the Commission's determination to review and address pipeline safety issues.

X. PHASE 1B

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[278] Ex. SCG-26 (Reyes Rebuttal), p. 9.

[279] The utilities have told their shareholders that their proposed PSEP would have a significant impact on its future earnings; PSEP is projected to constitute 28% of SoCalGas's capital spending by 2016, or about $1.4 billion. Ex. TURN-02 (Marcus Testimony), p. 3.

XI. PHASE 2: The Commission Should Not Make Any Specific Commitments Regarding the Scope of Work to be Performed in Phase 2 Until It Has Better Cost Information

It is unclear from the Sempra Utilities' testimony what, if any, issues they are asking the Commission to resolve in this decision with respect to Phase 2. TURN understands that a significant number of miles of pipe in less populated areas (non-HCA Class 1 or 2 pipe) that lack pressure test records from the time of installation will not be addressed in Phase 1 and will need to be addressed in Phase 2, in order to fulfill the test or replace requirement of D.11-06-017 that applies to all transmission pipeline. TURN recommends that the decision based on the record to date go no further than to direct the Sempra Utilities to present a plan at some point in the future to address this Class 1 and Class 2 pipe and any other issues that are unresolved or not completed in Phase 1.

At this point, the Commission does not have sufficient information to address one specific issue related to Phase 2 that was only briefly discussed in the written testimony: whether in Phase 2 the Sempra Utilities should be required to test or replace pre-1970 pipe for which the utility <u>does</u> retain pressure test records meeting the standards of the time the pipe was installed. TURN reads D.11-06-017 not to require testing or replacement in such cases as long as the pressure test record includes "all elements required by the regulations in effect when the test was conducted" and the pressure test had a duration of at least one hour.[280] However, in rebuttal testimony (contradicting their opening testimony), the Sempra Utilities take the position, without support in the ordering paragraphs, that D.11-06-017 requires such pipe to be tested or replaced in Phase 2.[281]

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[280] D.11-06-017, Ordering Paragraph ("OP") 3, p. 31.

[281] Ex. SCG-18 (Schneider Rebuttal, Sempra Utilities), p. 2. This testimony contradicts Mr. Schneider's opening testimony in which he stated that D.11-06-017 was unclear how to interpret

The Commission should not make a determination now on this issue because it has insufficient information in the record about the cost consequences of such a determination – except that the costs could be huge. The Sempra Utilities' witness, Mr. Schneider, testified that one-half or more of the total Sempra Utilities' system miles (more than 2,000 out of about 4,000 total) could need to be tested or replaced under their new interpretation of D.11-06-017,[282] but he had no idea how much this work would cost.[283] The expanded decision tree exhibit is no help in estimating the scope and costs resulting from the on this point. The mileage numbers for the relevant box, Box 8, are merged with Box 9 (no further action) so that it is impossible to discern how many miles of pipe would actually require some sort of action in Phase 2.[284] Before resolving this issue, the Commission should carefully consider the both the benefits and the costs of re-testing or replacing pipeline for which the utilities have the records of a pressure test of at least one hour meeting the standards of the time of installation.[285]

D.11-06-017 on this point. Ex. SCG-04 (Schneider Opening, Sempra Utilities), p. 119, fn. 70. The rebuttal argument overlooks the point that the operative ordering paragraphs, OPs 3 and 4, never state that all pipeline is required to have a pressure test record meeting Subpart J standards. In fact, the interpretation urged in the rebuttal testimony would render OP 3 meaningless.

[282] Tr., vol. 3, p. 466, line 7 – p. 472, line 13 (Schneider, Sempra Utilities).

[283] *Id.*, p. 472, lines 20-24.

[284] Ex. SCG-33-R (Expanded Decision Tree).

[285] TURN recognizes that CPSD staff appears to be leaning toward the view that such pipe should be re-tested to Subpart J standards. However, we urge the Commission to hold off on a final determination on this important issue until a better record of costs and benefits can be compiled, perhaps in R.11-02-019. One of TURN's concerns is that, even though CPSD only appears interested in re-testing such pipe, the Sempra Utilities are taking the position in this case that, for much of their pipe, they are unable to perform such testing without serious customer impacts and that they should therefore be permitted to engage in far more costly replacement of such pipe.

XII. CONCLUSION

For the above-describe reasons, TURN urges the Commission to adopt a decision that appropriately balances the need to move forward on pipeline safety-related activities and the need to ensure that ratepayers fund only the appropriate costs associated with those activities.

October 19, 2012

Respectfully submitted,

By: _______/s/_______________

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EXHIBIT F

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

SOUTHERN CALIFORNIA GENERATION COALITION OPENING BRIEF

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Dated: October 19, 2012

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SUMMARY OF RECOMMENDATIONS

On the basis of the evidentiary record in this proceeding, the Southern California Generation Coalition ("SCGC") respectfully requests that the Commission issue a decision that adopts the recommendations presented below. The recommendations are presented in the sequence in which they are discussed in the following brief:

- The Applicants' shareholders should bear the cost of testing or replacing all pipeline segments installed after July 1, 1961, for which the Applicants do not have sufficient documentation of post-construction pressure tests of the segments.
- There should be effective Commission review on a case-by-case basis of the Applicants' decisions to replace pipeline segments greater than 1,000 feet in length instead of pressure testing the segments.
    - The case-by-case review of replacement decisions should be through the Expedited Application Docket ("EAD") procedure.
    - The cost estimates presented in EAD proceedings should be at least Class 3 estimates.
- The Applicants' estimate of the cost of a replacement project, if approved in an EAD proceeding, should be the cost cap for the project, with costs that exceed the cap being recovered by the Applicants only if approved by the Commission after a subsequent reasonableness review.
- The Applicants' proposal for an Engineering Advisory Board as an alternative to Commission review of replacement decisions through the EAD process should be rejected.
- The Commission should permit the Applicants to continue to use the "grandfathering clause" in 49 CFR 192.619(c) as the basis for establishing a pipeline's MAOP if the MAOP is validated by meeting one of the four alternative conditions proposed by the Applicants to assure the safety of the pipeline:
    - <u>First alternative condition</u>: Post-construction strength test to at least 1.25 times MAOP with, for pipelines pressure tested before November 12, 1970, records of the test medium and test pressure and, for pipelines pressure tested after November 11, 1970, records

that satisfy 49 CFR 192.517 and that verify compliance with 49 CFR 192.505 or 192.507, as applicable.

- Second alternative condition: For pipelines placed in service prior to November 12, 1970, the MAOP has been lowered to less than or equal to 72 percent of the highest actual operating pressure documented during the five years preceding the pressure reduction.

- Third alternative condition: Complete non destructive examination using an inspection method capable of seam anomaly detection with subsequent remediation of seam defects that have predicted failure pressures of less than or equal to 1.39 times MAOP.

- Fourth alternative condition: After Transverse Field Inspection ("TFI") has been approved by the Commission, TFI followed by validation using non destructive evaluation methods capable of seam anomaly detection with remediation of seam defects that have predicted failure pressures less than or equal to 1.39 times MAOP.

- The Commission should reject the Applicants' estimates of annual PSEP costs as a basis for calculating the PSEP Surcharge.

- The Commission should allow the Applicants to recover only actually incurred costs through the Pipeline Safety Enhancement Plan Cost Recovery Account ("PSEPCRA") and the PSEP Surcharge.

  - The Applicants should debit their PSEPCRAs with actually incurred PSEP O&M expenses and actually incurred PSEP capital-related revenue requirement on a monthly basis, and the Applicants should credit their PSEPCRAs with actual revenues recovered through their PSEP Surcharges on a monthly basis.

  - Capital-related revenue requirement for a project should be debited to the PSEPCRA only after the underlying project becomes used and useful.

  - The PSEPCRA should include sub-accounts for recording debited O&M expenses and debited capital-related costs.

  - PSEPCRA year-end balances should be amortized through the Applicants' Annual Regulatory Account Balance Updates by adjusting the revenue requirements that underlie the Applicants' PSEPCRA Surcharges for the year in which the balances were accumulated so as to amortize the balances during the following year.

- The Commission should reject the Applicants' proposal to calculate the PSEP Surcharge by adding a year-end PSEPCRA under collection to or subtracting a year-end PSEPCRA over collection from a forecast of PSEP revenue requirement for the following year.

- The revenue requirements associated with PSEP projects should be incorporated into the Applicants' authorized revenue requirement in the Applicants' Test Year 2016 General Rate Case ("GRC").

    - No new costs should be booked into the Applicants' PSEPCRAs during 2016.

    - The Applicants' PSEPCRAs and the PSEP Surcharges should be terminated at the beginning of 2017

- The Applicants' request for permission to file expedited advice letters to adjust their forecasts of annual PSEP expenses should be rejected.

- If the Commission finds that the costs debited to the Applicants' Pipeline Safety and Reliability Memorandum Accounts ("PSRMAs") are reasonable so that the costs may be recovered from ratepayers, the Commission should permit the Applicants to transfer their PSRMA balances as a debit to their PSEPCRAs and to recover the balances through their PSEP Surcharges with collected revenues being credited to their PSEPCRAs.

- The Applicants should be required to submit their proposed annual PSEP Update Reports through an advice letter.

- If the Commission elects to approve the proposal for Backbone Transmission Service ("BTS") reservation charge credits, the cost of offering the credits should be recovered through the Backbone Transmission Balancing Account ("BTBA") from BTS customers.

- No costs should be incurred for Line 1600 in Phase 1A.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

SOUTHERN CALIFORNIA GENERATION COALITION
OPENING BRIEF

In accordance with Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the schedule established by Administrative Law Judge ("ALJ") Long,[1] the Southern California Generation Coalition ("SCGC") respectfully submits this opening brief in the captioned proceeding. The brief follows the Common Briefing Outline for this proceeding.

I. INTRODUCTION.

This proceeding addresses the Pipeline Safety Enhancement Plan ("PSEP") that the Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (jointly, "Applicants") submitted in Rulemaking ("R.") 11-02-019 on August 26, 2011, and amended on December 2, 2011.

SCGC participated actively in the development of the record in this proceeding. SCGC conducted extensive discovery, presented prepared direct and rebuttal testimony by Catherine E.

[1] Transcript ("Tr.") 1633.

Yap, and participated in the hearing conducted by ALJ Long. On the basis of the evidentiary record in this proceeding, SCGC respectfully requests that the Commission issue a decision that adopts the recommendations presented below. The recommendations are presented in the sequence in which they are discussed in this brief:

- The Applicants' shareholders should bear the cost of testing or replacing all pipeline segments installed after July 1, 1961, for which the Applicants do not have sufficient documentation of post-construction pressure tests of the segments.

- There should be effective Commission review on a case-by-case basis of the Applicants' decisions to replace pipeline segments greater than 1,000 feet in length instead of pressure testing the segments.

    - The case-by-case review of replacement decisions should be through the Expedited Application Docket ("EAD") procedure.

    - The cost estimates presented in EAD proceedings should be at least Class 3 estimates.

- The Applicants' estimate of the cost of a replacement project, if approved in an EAD proceeding, should be the cost cap for the project, with costs that exceed the cap being recovered by the Applicants only if approved by the Commission after a subsequent reasonableness review.

- The Applicants' proposal for an Engineering Advisory Board as an alternative to Commission review of replacement decisions through the EAD process should be rejected.

- The Commission should permit the Applicants to continue to use the "grandfathering clause" in 49 CFR 192.619(c) as the basis for establishing a pipeline's MAOP if the MAOP is validated by meeting one of the four alternative conditions proposed by the Applicants to assure the safety of the pipeline:

    - <u>First alternative condition</u>: Post-construction strength test to at least 1.25 times MAOP with, for pipelines pressure tested before November 12, 1970, records of the test medium and test pressure and, for pipelines pressure tested after November 11, 1970, records that satisfy 49 CFR 192.517 and that verify compliance with 49 CFR 192.505 or 192.507, as applicable.

    - <u>Second alternative condition</u>: For pipelines placed in service prior to November 12, 1970, the MAOP has been lowered to less than or equal to 72 percent of the highest actual operating pressure documented during the five years preceding the pressure reduction.

  - Third alternative condition: Complete non destructive examination using an inspection method capable of seam anomaly detection with subsequent remediation of seam defects that have predicted failure pressures of less than or equal to 1.39 times MAOP.

  - Fourth alternative condition: After Transverse Field Inspection ("TFI") has been approved by the Commission, TFI followed by validation using non destructive evaluation methods capable of seam anomaly detection with remediation of seam defects that have predicted failure pressures less than or equal to 1.39 times MAOP.

- The Commission should reject the Applicants' estimates of annual PSEP costs as a basis for calculating the PSEP Surcharge.

- The Commission should allow the Applicants to recover only actually incurred costs through the Pipeline Safety Enhancement Plan Cost Recovery Account ("PSEPCRA") and the PSEP Surcharge.

  - The Applicants should debit their PSEPCRAs with actually incurred PSEP O&M expenses and actually incurred PSEP capital-related revenue requirement on a monthly basis, and the Applicants should credit their PSEPCRAs with actual revenues recovered through their PSEP Surcharges on a monthly basis.

  - Capital-related revenue requirement for a project should be debited to the PSEPCRA only after the underlying project becomes used and useful.

  - The PSEPCRA should include sub-accounts for recording debited O&M expenses and debited capital-related costs.

  - PSEPCRA year-end balances should be amortized through the Applicants' Annual Regulatory Account Balance Updates by adjusting the revenue requirements that underlie the Applicants' PSEPCRA Surcharges for the year in which the balances were accumulated so as to amortize the balances during the following year.

- The Commission should reject the Applicants' proposal to calculate the PSEP Surcharge by adding a year-end PSEPCRA under collection to or subtracting a year-end PSEPCRA over collection from a forecast of PSEP revenue requirement for the following year.

- The revenue requirements associated with PSEP projects should be incorporated into the Applicants' authorized revenue requirement in the Applicants' Test Year 2016 General Rate Case ("GRC").
    - No new costs should be booked into the Applicants' PSEPCRAs during 2016.
    - The Applicants' PSEPCRAs and the PSEP Surcharges should be terminated at the beginning of 2017
- The Applicants' request for permission to file expedited advice letters to adjust their forecasts of annual PSEP expenses should be rejected.
- If the Commission finds that the costs debited to the Applicants' Pipeline Safety and Reliability Memorandum Accounts ("PSRMAs") are reasonable so that the costs may be recovered from ratepayers, the Commission should permit the Applicants to transfer their PSRMA balances as a debit to their PSEPCRAs and to recover the balances through their PSEP Surcharges with collected revenues being credited to their PSEPCRAs.
- The Applicants should be required to submit their proposed annual PSEP Update Reports through an advice letter.
- If the Commission elects to approve the proposal for Backbone Transmission Service ("BTS") reservation charge credits, the cost of offering the credits should be recovered through the Backbone Transmission Balancing Account ("BTBA") from BTS customers.
- No costs should be incurred for Line 1600 in Phase 1A.

II. BACKGROUND.

In D.11-06-017, the Commission concluded "that all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety."[2] Consistent with that conclusion, the Commission found: "Historic exemptions must come to an end with an orderly and cost-conscious implementation plan."[3] Accordingly, D.11-02-017 required the Applicants as well as Southwest Gas Corporation and Pacific Gas & Electric Company to file plans to "comply with the requirement that all in-service natural gas

[2] D.11-06-017, p. 18 (June 9, 2011).

[3] *Ibid*.

transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c)."[4]

As an interim measure, the Commission required "California natural gas transmission pipeline operators to prepare and file a comprehensive Implementation Plan to replace or pressure test all natural gas transmission pipeline in California that has not been tested or for which reliable records are not available."[5] The Commission directed that the implementation plans should "start with pipeline segments in higher priority Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority for pressure testing."[6] Pipeline segments that could not be pressure tested could be replaced, but implementation plans "must set forth criteria on which pipeline segments were identified for replacement instead of pressure testing."[7] The Commission emphasized that containing the cost of attaining the safety objectives of D.11-09-017 was an overarching objective: "Obtaining the greatest amount of safety value, i.e., reducing safety risk, for ratepayer

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[4] D.11-06-017, p. 31 (Ordering Paragraph 4) (June 9, 2011).

[5] *Ibid*, p. 18.

[6] *Ibid;* Class locations are defined in 49 Code of Federal Regulations ("CFR") §192:

> (1) A Class 1 location is:
> > (i) an offshore area; or
> > (ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.
>
> (2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.
> (3) A Class 3 location is:
> > (i) Any class location unit that has 46 or more buildings intended for human occupancy; or
> > (ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)
>
> (4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

[7] *Ibid*, p. 32 (Ordering Paragraph 6).

expenditures will be an overarching Commission goal in reviewing the plans presented by the gas transmission system operators."[8]

A. The Applicants' Proposed PSEP.

Pursuant to the provision in D.11-06-017 for implementation plans to "start with" pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas with "lower priority" being given to pipeline segments in other areas, the Applicants propose that their PSEP should proceed in two phases. In Phase 1, the Applicants would pressure test or replace transmission pipelines located in Class 3 and 4 locations and Class 1 and Class 2 high consequence areas that "do not have sufficient documentation or pressure testing to satisfy modern standards."[9]

Phase 1, in turn, would be subdivided into Phase 1A and Phase 1B. In Phase 1A, which spans the four years 2012 through 2015, the Applicants would pressure test or replace 385 miles of transmission pipelines located in Class 3 and 4 locations and Class 1 and Class 2 high consequence areas that lack sufficient documentation of pressure testing except the miles of pipeline that "cannot be tested or replaced with manageable customer impacts" during Phase 1A."[10] In Phase 1B, which spans the six years 2016 through 2021, the Applicants would pressure test or replace the pipeline segments that would have been done during Phase 1A but which could not be tested or replaced in Phase 1A with manageable customer impacts.[11] Also in Phase 1B, the Applicants would replace all pre-1946 pipeline segments that "were manufactured using non-state-of-the-art construction and fabrication methods."[12]

[8] D.11-09-017, p. 22.

[9] Ex. ("Ex.") SCG-02, p. 19 (Morrow).

[10] *Ibid*.

[11] *Ibid*.

[12] *Ibid*.

Phase 2 would begin at the same time as Phase 1B in 2016 but would extend into the indefinite future.[13] In Phase 2, the Applicants propose to "address all remaining transmission pipelines that do not have sufficient documentation of pressure testing to satisfy the Commission's directives that all transmission pipelines "be brought into compliance with modern standards for safety" without reliance on "historic exemptions."[14]

B. Procedural History.

The Commission transferred consideration of the Applicants' PSEP from R.11-02-019 to the Applicants' Triennial Cost Allocation Proceeding ("TCAP") in Application ("A.") 11-11-002 in D.12-04-021.[15] The Commission also authorized the Applicants to establish PSRMAs to record the "escalated direct and incremental overhead costs" of implementing the PSEP.[16] The Commission said that it would consider whether costs recorded in the PSRMAs may be recovered from ratepayers in the TCAP.[17]

The Applicants established their PSRMAs through advice letters dated May 18, 2012,[18] and the PSRMAs became effective on May 20, 2012.[19] On May 25, 2012, the Applicants filed a motion to commence recovery of amounts recorded in the PSRMAs.[20] The Commission has not acted on that motion.

The Applicants' direct testimony was submitted with their application on August 26, 2011, and was amended on December 2, 2011. Direct testimony was filed on June 19, 2012, by

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13 *Ibid*, pp. 19-20.

14 D.11-06-017, pp. 18-19.

15 D.12-04-021, p. 12, Ordering Paragraph 1 (April 19, 2012).

16 D.12-04-021, *ibid*, Ordering Paragraph 3.

17 *Ibid*, p. 7.

18 SoCalGas Advice Letter 4359; SDG&E Advice Letter 2106-G.

19 Tr. 885 (Applicants/Buczkowski).

20 Motion of Applicants for Interim Recovery of Costs recorded in PSRMA, A-11-11-002 (May 25, 2012).

SCGC and by the Division of Ratepayer Advocates ("DRA"), The Utility Reform Network ("TURN"), the Southern California Indicated Producers ("SCIP"), and the Utility Workers Union of America ("UWUA"). Rebuttal testimony was filed on July 18, 2012, by the Applicants, SCGC, and the Southern California Edison Company ("SCE").

The hearing commenced on August 20, 2012, and extended over nine days, resulting in 1640 transcript pages and 114 exhibits.

III. RESPONSIBILITY FOR PHASE 1 COSTS.

A threshold issue in this proceeding is whether shareholders or ratepayers should be responsible for pressure testing or replacing pipeline segments that lack sufficient documentation of a pressure test. In determining the extent to which shareholders rather than ratepayers should bear PSEP costs, SCGC witness Yap focused on pipelines constructed after the Commission's General Order No. 112 became effective.

The Commission adopted General Order No. 112 on December 28, 1960, and the Order became effective on July 1, 1961.[21] General Order No. 112 and its successors[22] require operators of natural gas pipelines to pressure test pipelines as specified in the General Orders and require retention of documentation of the pressure testing. For all pipeline segments constructed after General Order No. 112 became effective on July 1, 1961, the Applicants' shareholders should bear the cost of pressure testing or replacing the segments to the extent that the pressure testing

[21] D.61269, 58 CPUC 413 (December 28, 1960).

[22] General Order No. 112-A, D.66339 (December 3, 1963, effective January 1, 1964).
General Order No. 112-B, D.73223 (October 24, 1967, effective December 1, 1967).
General Order No. 112-C, D.78513 (April 2, 1971, effective April 30, 1971).
General Order No. 112-C, D.80208 (July 18, 1972, effective July 18, 1972).
General Order No. 112-C, D.82467 (February 13, 1974, effective February 13, 1974).
General Order No. 112-C, D.85375 (January 27, 1976, effective January 27, 1976).
General Order No. 112-C, D.86874 (January 18, 1977, effective January 18, 1977).
General Order No. 112-D, D.90372 (June 5, 1979, effective June 5, 1979).
General Order No. 112-E, D.95-08-053 (August 11, 1985, effective September 10, 1995).

or replacement is necessitated by the Applicants' failure to retain sufficient documentation showing that the pipeline segments were pressure tested.

A. Applicable Standards and Burden of Proof.

The Applicants propose a costly array of PSEP projects and seek ratepayer funding for the projects. The Applicants bear the burden of proving that their proposed projects are reasonable and prudent so that ratepayers should be required to bear the cost of the projects. The Applicants must bear their burden of proof by demonstrating that their positions and proposals are supported by a preponderance of the evidence.

1. Burden of proof.

Under Section 451 of the Public Utilities Code, the Commission is responsible for ensuring that all rates demanded or received by a public utility are just and reasonable: "All charges demanded or received by any public utility… for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable."[23] Furthermore, "no public utility shall change any rate…. except upon a showing before the commission and a finding by the commission that the new rate is justified."[24]

In order to discharge its responsibility to ensure that all rates demanded or received by a public utility are just and reasonable, the Commission requires that a public utility demonstrate with admissible evidence that the costs which it seeks to include in its revenue requirement are reasonable and prudent.[25] The Commission has the authority to disallow rate recovery of costs that are unreasonably or imprudently incurred by a utility.[26]

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[23] Cal.Pub.Util. Code §451.

[24] Cal.Pub.Util. Code §454.

[25] D.06-05-016, p. 8, (May 11, 2005).

[26] Cal.Pub.Util. Code §§451, 454.

As the parties who are seeking recovery of costs from ratepayers in this proceeding, the Applicants must meet their burden of proving that they are entitled to the relief they are seeking.[27] Accordingly, the Applicants have the burden of affirmatively establishing the reasonableness of all aspects of their application. Conversely, other parties do not have the burden of proving the unreasonableness of Applicants' proposals.[28]

2. Standard of proof.

Applicants must meet their burden of proof by demonstrating that their positions and proposals are supported by a preponderance of the evidence.[29] Preponderance of the evidence is usually defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[30] Thus, the Applicants must present evidence that supports adoption of their proposals that outweighs the evidence that supports an alternative outcome.

B. Transmission Pipeline Testing and Record-keeping Requirements and Standards.

On December 28, 1960, the Commission adopted General Order No. 112 to establish regulations governing the design, construction, testing, maintenance, and operation of gas transmission and distribution piping systems.[31] General Order No. 112 became effective on July 1, 1961. The General Order adopted by reference, with modifications, the 1958 edition of Section 8 of the American Standards Association ("ASA") Code for Pressure Piping, Gas Transmission and Distribution Piping Systems, ASA B31.8-1958 ("B31.8 Code"). Subsequent

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[27] D.06-05-016, *Ibid*.

[28] *Ibid*.

[29] *Ibid*.

[30] D.08-12-058, *citing* Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184.

[31] Decision 61269 (December 28, 1961).

to the issuance of General Order No. 112, the General Order was revised twice in General Order Nos. 112-A and 112-B to reflect changes in the B31.8 Code.[32]

Pursuant to the Natural Gas Pipeline Safety Act of 1968, the United States Department of Transportation issued gas pipeline safety standards under Title 49, Part 192, of the Code of Federal Regulations, effective November 12, 1970. By Resolution No. G-1499, the Commission adopted Part 192 to supplement General Order No. 112-B, but ordered that all standards in General Order No. 112-B that were additional or more stringent than Part 192 would remain in effect.[33] Resolution No. G-1499 became effective on November 12, 1970, the same date on which Part 192 became effective.[34] The provisions of 49 CFR Part 192, as strengthened in accordance with Resolution No. G-1499, were incorporated into the Commission's regulations in General Order No. 112-C, effective April 30, 1971.[35]

General Order No. 112, effective July 1, 1961, and 49 CFR Part 192, effective November 12, 1970, contain provisions establishing the test pressure that must be attained to permit operation of a pipeline segment at a given Maximum Allowable Operating Pressure ("MAOP"), the duration of the pressure test, and the records that the pipeline operator must retain to document the test.

1. Test pressure required to validate the MAOP for a pipeline.

General Order No. 112 required that all pipelines that are operated at hoop stress of 20 percent or more of the Specified Minimum Yield Strength ("SMYS") shall be tested to show a

[32] The first revision was made on December 3, 1963, by Decision No. 66399 (61 CPUC 744); in which the Commission issued General Order No. 112-A, effective January 1, 1964, adopting the ASA B31.8-1963 Code with modifications. The second revision was made on October 24, 1967, by Decision No. 73223 (67 CPUC 585); in which the Commission issued General Order No. 112-B, effective December 1, 1967, adopting the USAS B31.8-1967 Code with modifications.

[33] *See* D.78513, p. 3 (April 12, 1971).

[34] *Ibid*.

minimum test pressure in Class 1 and Class 2 locations of 1.25 times MAOP and a minimum test pressure in Class 3 and Class 4 locations of 1.5 times MAOP.[36]

Section 192.619 of Part 192 requires the same minimum test pressures in Class 2 locations (1.25 times MAOP) and Class 3-4 areas (1.5 times MAOP) as General Order No. 112.[37] However, for Class 1 locations, Section 192.619 permits an MAOP to be validated by a test pressure of 1.1 times MAOP rather than 1.25 times MAOP.[38] In Resolution No. G-1499, the Commission directed that if California standards were more stringent than Federal standards, the California standards should be retained.[39] Thus, the General Order No. 112 requirement of testing to 1.25 times MAOP was retained for Class 1 areas in California, and General Order No. 112-C required testing to 1.25 times MAOP as the test pressure for Class 1 areas.[40]

The testing requirement for Class 1 areas was subsequently changed. In 1995, the Commission determined: "Automatically adopting changes in federal standards will eliminate

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[35] D. 78513, *ibid*, Appendix A.

[36] General Order No. 112, §§209.11 and 209.12 provide as follows:

> 209.11 Minimum test pressure in Class 1 and Class 2 locations shall be 1.25 times maximum operating pressure or 90% of the mill test pressure, whichever is the lesser.
> 209.12 Minimum test pressure in Class 3 and Class 4 locations shall be 1.50 times maximum operating pressure or 90% of the mill test pressure, whichever is the lesser.

In Class 3 and 4 areas, the mill test pressures typically would be at higher levels so that a 1.5 times MAOP would be less than the mill test pressure. Tr. 390 (Applicants/Schneider). The mill test pressure may be lower than test pressure more frequently in Class 1 and 2 areas. *Ibid,* Tr. 391.

[37] 49 CFR §192.619(a)(2)(ii). Like General Order 112, 49 CFR §192.619(a) provided for factors that could result in the MAOP being even lower than the test pressure divided by 1.1 for Class 1 areas, 1.25 for Class 2 areas, or 1.5 for Class 3-4 areas. For example, if the design pressure of the weakest element in the segment were lower, the design pressure would determine the MAOP. 18 CFR §192.619(a)(1) (2011). Likewise, if the operator of the pipeline determined that the maximum safe pressure should be lower after considering "the history of the segment" particularly no corrosion or actual operating pressure," the MAOP should be lower. 49 CFR §192.619(a)(4).

[38] Fed. Reg., Vol. 35, No. 161, p. 13273 (August 17, 1970).

[39] D.78513, p. 3 (April 2, 1971).

[40] D.78513, General Order No. 112-C, p. 133 (January 12, 1971).

the lag time in changing California requirements to conform."[41] In 1995 the Commission adopted General Order No. 112-E to automatically adopt 49 CFR Part 192 revisions as they became effective at the Federal level.[42] As a result, the Federal requirement of a test pressure of 1.1 times MAOP in Class 1 areas now applies in California.

2. Duration of test.

A significant difference between General Order No. 112 as effective in 1961 and 49 CFR Part192 as effective in 1970 was that the Federal regulation requires test pressures to be maintained for a longer period than under the California regulation. General Order No. 112 required maintaining a static test pressure for one hour: "Test pressure shall be maintained until the pressure has stabilized in all portions of test sections. In no event shall the test at maximum pressure be less than one hour."[43] Part 192, however, required that the test pressure be maintained for 8 hours.[44]

3. Record retention.

Both General Order No. 112 and Part 192 contain record retention requirements. General Order No. 112 required retention of records for the useful life of the pipeline showing the type of fluid used for the test and the test pressure.[45] General Order No. 112 emphasized in Section 301.1 that the utility is responsible for maintaining the required records:

> 301.1 The responsibility for the maintenance of necessary records to establish that compliance with these rules has been accomplished rests with the utility. Such records shall be available

[41] D.95-08-053, p. 10 (August 11, 1995).

[42] D.95-08-053, p. 3

[43] General Order No. 112, §209.14.

[44] 49 CFR §192.505(c); Federal Registry, Vol. 35, No. 161, p. 13270 (August 19, 1970).

[45] General Order No. 112, §841.417.

> for inspection at all times by the Commission or the Commission Staff.[46]

By contrast, 49 CFR §192.517 contained a more detailed record retention provision:

> Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§192.505 and 192.507. The record must contain at least the following information:
>
> (a) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
> (b) Test medium used.
> (c) Test pressure.
> (d) Test duration.
> (e) Pressure recording charts, or other record of pressure readings.
> (f) Elevation variations, whenever significant for the particular test.
> (g) Leaks and failures noted and their disposition.[47]

C. Cost Responsibility.

In D.11-02-019 the Commission ordered "all California natural gas transmission pipeline operators to prepare Implementation Plans to either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test."[48] The Applicants admitted that they cannot locate sufficient documentation of pressure testing for a number of pipeline segments that were constructed after General Order No. 112 became effective on July 1, 1961. Insofar as pressure testing and record retention requirements were explicitly imposed on the Applicants by regulation as of July 1, 1961, the Applicants' shareholders should bear the cost of testing or replacing all pipeline segments installed after July 1, 1961, for which the Applicants do not have sufficient documentation of post-construction pressure tests of the segments.

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[46] General Order No. 112, *ibid*, Section 301.1.

[47] 49 CFR §192.517, Federal Registry, Vol. 35, No. 161, p. 13270 (August 19, 1970).

SCGC witness Yap did not address shareholder responsibility for periods prior to 1961, but SCGC believes other parties will address that issue.

1. 1961 to 1970 pipelines.

According to SoCalGas witness Schneider, in response to a January 3, 2011 letter from the Commission's Executive Director, Paul Clanon, the Applicants "undertook an intensive record search to identify gas transmission lines that had not previously been pressure tested to a 1.25 times MAOP safety margin."[49] The Applicants reviewed each pipeline's records to determine if sufficient documentation existed to demonstrate a post-construction test to the safety margin of 1.25 times MAOP.[50] As a result of their search, the Applicants found twenty miles of pipeline in Class 3 and 4 areas or Class 1 and 2 high consequence areas that were constructed after the effective date of General Order No. 112 but before the effective date of 49 CFR Part 192.[51] The Applicants estimated that they would incur an operations and maintenance ("O&M") cost of $3.8 million for pressure testing and a direct capital cost of $69.6 million for replacing pipeline segments that lacked sufficient documentation. The associated revenue requirement would be $247.9 million over the life of the assets.[52]

The cost of pressure testing or replacing pipeline segments that were constructed between 1961 and 1970 that lack sufficient documentation could be much less. Witness Schneider testified that the Applicants' records review has continued, and they have identified an additional three miles of 1961-1970 pipeline for which "we have the information that we would consider to

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[48] D.11-06-017, p. 19.

[49] Ex. SCG-18, Schneider Rebuttal, p. 11.

[50] *Ibid*.

[51] Ex. SCG-18, p. 12, Figure DMS-3 (Applicants/Schneider).

[52] Ex. SCG-1, Yap Direct, p. 14 (SCGC/Yap).

be in compliance."[53] Also, the Applicants have now determined that approximately eight of the twenty miles were not constructed during the 1961-1970 period.[54] Thus, it now appears that only about nine miles of 1961-1970 vintage pipeline segments lack sufficient documentation of pressure testing.

Regardless of the precise mileage and the associated cost of pressure testing or replacing the 1961-1970 pipeline segments for which the Applicants lack sufficient documentation of pressure testing, the Applicants' shareholders should bear the cost of pressure testing the pipeline segments. Section 301.1 of General Order No. 112 explicitly imposed on the Applicants responsibility for "the maintenance of necessary records to establish that compliance with these rules had been accomplished…."[55] Presumably, the Applicants conducted post-construction pressure tests of post-1961 pipelines in compliance with the Commission's regulations and recovered the cost of the pressure testing from ratepayers. But for the failure of the Applicants to maintain the necessary records, it would not be necessary to pressure test or replace any 1961-1970 vintage pipeline segments during the Applicants' Phase 1A. SCGC witness Yap testified: "Ratepayers should not be responsible for paying for re-testing pipelines for which the Applicants failed to meet their obligation to maintain adequate records."[56] Thus, SCGC recommends that the Commission should require the Applicants' shareholders to bear the cost of pressure testing or replacing 1961-1970 vintage pipeline segments for which the Applicants lack sufficient documentation of pressure testing.

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[53] Tr. 415 (Applicants/Schneider).

[54] Tr. 415-416 (Applicants/Schneider).

[55] General Order 112, Section 301.1.

2. Post 1970 pipelines.

Applicants' witness Morrow testified that there are eight miles of post-1970 pipelines which lack sufficient documentation of pressure testing.[57] As explained above, 49 CFR 192.517 contains a detailed record retention requirement for each pressure test performed under 49 CFR Part 192.

It appeared from the Applicants' direct testimony that the Applicants understood that if they failed to find sufficient documentation of pressure tests for pipeline segments constructed after the 1970 effective date of 49 CFR Part 192, the shareholders should bear the cost for pressure testing or replacing the post-1970 pipeline segments that needed to be pressure tested or replaced under D.11-09-017. Witness Morrow testified: "This proposed Pipeline Safety Enhancement Plan does not include any cost for testing or replacing pipelines constructed post-1970."[58]

However, upon cross-examination, it became clear that witness Morrow's statement that the Applicants' PSEP "does not include any cost for testing or replacing pipelines constructed post-1970" did *not* mean that shareholders would bear the cost of pressure testing or replacing the eight miles of post-1970 pipeline segments for which the Applicants lack sufficient documentation of pressure testing. Witness Morrow clarified that the costs of pressure testing or replacing the post-1970 pipelines that lack sufficient documentation of pressure testing will be "funded through our existing O&M and capital budget that's been established for the utility."[59] He explained further that "we are seeking the full recovery of our capital investments here,

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[56] Ex. SCGC-1, p. 14 (SCGC/Yap).

[57] *Ibid*.

[58] Ex. SCG-02, p. 18, Footnote 16 (Applicants/Morrow).

[59] Tr. 103 (Applicants/Morrow).

yes"[60] The passage in the Applicants' direct testimony about how the PSEP "does not include any cost for testing or replacing pipelines constructed post-1970" only means "that we're not seeking incremental cost recovery."[61] Witness Morrow elaborated: "We will recover the capital costs. We are not seeking any incremental capital to do this work. We are not seeking any incremental O&M to do this work."[62]

Like the cost of pressure testing or replacing the 1961-1970 pipeline segments that lack sufficient documentation of pressure testing, the Applicants' shareholders should bear the full cost of all O&M and capital expense that is involved with pressure testing or replacing the post-1970 pipeline segments that lack sufficient documentation of pressure testing. The record retention requirement contained in 49 CFR §192.517 is, if anything, clearer than the record retention requirement in Section 301.1 of General Order 112. But for the Applicants' failure to comply with the explicit record retention requirement, pressure testing or replacing the eight miles of post-1970 pipeline would not be necessary. No ratepayer contributed funds should be used in any way to cover the cost of pressure testing or replacing the eight miles of post-1970 pipeline for which the Applicants lack sufficient documentation.

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

The Applicants' proposed Phase 1A includes a defined set of high priority pipeline segments. On January 3, 2011, the Commission's Executive Director notified the Applicants that the National Transportation Safety Board ("NTSB") had issued urgent safety recommendations in connection with NTSB investigation of the natural gas pipeline rupture in

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[60] Tr. 106 (Applicants/Morrow).

[61] *Ibid*.

[62] Tr. 108 (Applicants/Morrow).

San Bruno, California, on September 9, 2010.[63] The Executive Director required the Applicants to report on the steps that the Applicants would take to comply with NTSB's recommendations. The NTSB's recommendations required an analysis and action for all pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas for which the Applicants lack a record of pressure testing.[64]

In response, the Applicants reviewed the records of SoCalGas' 1,416 miles and SDG&E's 206 miles of pipelines that meet the NTSB's criteria of being in Class 3 and Class 4 locations or Class 1 and Class 2 high consequence areas.[65] The Applicants called these miles "Criteria Miles."[66] The Applicants undertook a record search to identify pipeline segments in the Criteria Miles that had not been pressure tested to 1.25 times MAOP.[67]

The Applicants conducted their record search to identify whether gas transmission lines had been tested to a 1.25 times MAOP safety margin rather than a 1.5 times MAOP safety margin as specified in General Order No. 112 and 49 CFR §192.619 because it was a long seam that failed in the San Bruno explosion, and industry papers indicate 1.25 times MAOP is the "stability threshold" for long seams:

> Q: Why for those miles did you require only 1.25 as opposed to the 1.5 factor given that some of those miles might be in Class 3 or 4 areas?
>
> A. Right. So you know, again, post-San Bruno, you know, we want to – we wanted to identify and target where we needed to work on our system. And so there's industry papers and information that talk about 1.25 times the

[63] Report of Applicants on Actions Taken in Response to the NTSB Safety Recommendations, R.11-02-019, p. 1 (April 15, 2011).

[64] *Ibid*.

[65] *Ibid*, p. 2.

[66] *Ibid*.

[67] Ex. SCG-18, p. 11 (Applicants/Schneider).

> MAOP being the stability threshold for the long seams and the fact that a long seam is what filed at San Bruno.[68]

The Commission apparently concurs with the Applicants' selection of 1.25 times MAOP as a criterion. The Commission explained in D.11-09-017: "The 1.25 factor was from a United States Department of Transportation Office of Pipeline Safety publication which determines that manufacturing defects that survive such a test are stable at a MAOP of 80% of the test pressure."[69]

The Applicants then divided the Criteria Miles into four categories. Category 1 consisted of Criteria Miles that had a documentation of a *hydrostatic pressure test* to 1.25 times or more of the MAOP.[70] Category 2 consisted of Criteria Miles that had documentation of a *pressure test using a medium other than water* to 1.25 times or more of MAOP.[71] Category 3 consisted of pipelines that had documentation to show that the pipeline had *operated continuously at a pressure* of 1.25 times or greater than the current MAOP.[72] Category 4 consisted of Criteria Miles that *do not have sufficient documentation of a hydrostatic pressure test, a pressure test using a medium other than water, or an in-service pressure test* to 1.25 times or more of the MAOP.[73]

Phase 1A includes all Category 4 Criteria Miles except "pipeline segments that would otherwise be addressed in Phase 1A, but which cannot be addressed in the near-term due to the

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[68] Tr. 417 (Applicants/Schneider).

[69] D.11-09-017, p. 11, footnote 14.

[70] Ex. SCG-18, p. 12, footnote 15 (Applicants/Schneider).

[71] *Ibid*.

[72] *Ibid*, footnote 16. The Applicants interpret D.11-06-017 as not allowing for an in-service pressure test. *Ibid*. Accordingly, the Applicants say that "for purposes of our PSEP filing our Category 3 pipelines are included in a later Phase." *Ibid*.

[73] *Ibid*, p. 12.

need to construct new infrastructure to maintain service during pressure testing."[74] Currently, the only Category 4 pipeline that is assigned to Phase 1B insofar it "cannot be addressed in the near-term due to the need to construct new infrastructure" is Line 1600 in the SDG&E service territory.[75]

A. Decision-Making Process (Test or Replace, Decision Tree).

The Applicants developed a decision tree to determine the treatment to be given to Category 4 Criteria Miles, that is, pipelines operated in Class 3 or 4 locations or high consequence area that do not have sufficient documentation of pressure testing to 1.25 times MAOP.[76] Under the decision tree, all Phase 1 pipeline segments fall into one of three categories: (1) pipeline segments that are 1,000 feet or less in length, (2) pipeline segments greater than 1,000 feet in length that can be removed from service to pressure testing, and (3) pipeline segments greater than 1,000 feet in length that cannot be removed from service for pressure testing.[77]

For pipeline segments that are 1,000 feet or less in length, Applicants believe that it would typically be more cost effective to abandon and replace the segments than to perform a pressure test.[78] Accordingly, in the PSEP, all segments 1,000 feet or less in length are scheduled for replacement followed by abandonment,[79] unless, as discussed below, the Commission approves non-destructive examination as an alternative to replacement or pressure testing of short segments.[80]

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[74] Ex. SCG-4, p. 60 (Applicants/Schneider).

[75] Tr. 450 (Applicants/Schneider).

[76] Ex. SCG-4, p. 61 (Applicants/Schneider).

[77] *Ibid*, p. 52.

[78] *Ibid*, p. 53.

[79] *Ibid*, p. 54.

[80] *Ibid*.

Under the decision tree, all Phase 1 pipeline segments that are greater than 1,000 feet in length are either those "than can be removed from service for pressure testing" or those that "cannot be removed from service for pressure testing."[81] The Commission recognized the substantial cost and rate implications of a decision to replace rather than pressure test a pipeline segment. The Commission specifically directed that the Applicants' implementation plan "must set forth criteria on which pipeline segments were identified for replacement instead of pressure testing."[82]

The sole criterion that the Applicants offered in their direct testimony for determining whether a pipeline segment would be replaced instead of pressure testing is stated in the form of a question in the Applicants' decision tree: "Can pipeline be taken out of service with manageable customer impact?"[83] The Applicants subsequently indicated at a May 30, 2012 workshop that they would provide an explanation of what was meant by the term, "manageable customer impacts."[84] The Applicants said in a data response to SCGC that they anticipated "making the criteria available to parties by including it in rebuttal testimony."[85]

The Applicants' more fulsome presentation of criteria for identifying pipeline segments that should be replaced rather than pressure tested was included in Applicants' witness Phillips July 18, 2012 rebuttal testimony.[86] Witness Phillips presented a "Replacement Decision Tree" for Category 4 pipeline segments greater than 1,000 feet in length. Following the Replacement Decision Tree, the Applicants would first ask whether a core customer outage could be

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[81] *Ibid*, p. 52.

[82] D.11-06-017, p. 32 (Ordering Paragraph 6).

[83] Ex. SCG-04, p. 61 (Figure IV-1).

[84] Tr. 1146 (Applicants/Phillips).

[85] Ex. SCGC-1, Attachment O, SoCalGas/SDG&E Response to SCGC-19.3.

[86] Tr. 1146 (Applicants/Phillips).

mitigated. If it could not, the pipeline would be replaced.[87] If a core customer outage could be mitigated, the Applicants would then review noncore customer impact and, also, compare the cost of hydrostatic testing to the cost of replacement.[88] Based upon those considerations and an "engineering review," the Applicants would reach a determination about whether to replace rather than pressure test a pipeline segment.[89]

In addition to his "Replacement Decision Tree," witness Phillips identified five "principles" that would be followed in determining whether to replace rather than pressure test a segment greater than 1,000 feet in length:

> The Replacement Decision Tree is based on the following principles: (1) That SoCalGas and SDG&E will not interrupt service to its core customers in order to pressure test a pipeline; (2) That SoCalGas and SDG&E will work with noncore customers to determine if an extended outage is possible; (3) That SoCalGas and SDG&E will, where necessary, temporarily interrupt non-core customers as provided for in their tariffs; (4) That SoCalGas and SDG&E will work with non-core customers to plan, where possible, service interruptions during schedule maintenance, down time or off peak seasons, and (5) That SoCalGas and SDG&E will consider cost and engineering factors for the improvement of the pipeline asset.[90]

The Applicants admit that their proposed "Replacement Decision Tree" and associated "principles" are not clear-cut criteria that would mechanically drive a decision to replace rather than pressure test. The Applicants contend that a "yes/no" decision tree is not possible and that "judgment" is needed. Witness Phillips explained:

> I would say it was the understanding that if we were to put together a decision tree with all of those things that I mentioned yesterday, and more that I didn't mention yesterday, that would be very complex. And even if we were to produce a decision tree that had

[87] Ex. SCG-20, p. 8 (Figure 1-Replacement Decision Tree).

[88] *Ibid*.

[89] *Ibid*.

[90] *Ibid*, pp. 8-9.

> all of that information in it, all of those different branches of the decision tree, there would still be judgment that needed to be used on some of those points in the decision tree.
>
> I think what everybody would like to have in a decision tree is something that is an easy yes/no answer. Is it 346 pipe or not? Is it 1,000 ft., is it more than – less than 1,000 ft., or is it more than 1,000 ft. And in thinking through what we think the parties want on a decision tree, it is something that is very yes/no in all of its decision points. And we don't think it is possible at this point to produce something that is yes/no on a decision tree.[91]

The Applicants' proposed "Replacement Decision Tree" and associated "principles" leaves substantial leeway for the Applicants to exercise judgment in deciding whether to replace rather than pressure test pipeline segments that lack sufficient documentation of pressure testing.

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

Given the Commission's determination in D.11-09-017 that "obtaining the greatest amount of safety value and for ratepayer expenditures will be an overarching Commission goal,"[92] the Applicants' decisions to replace rather than pressure test pipeline segments greater than 1,000 feet in length should be reviewed on a case-by-case basis by the Commission. The direct cost of replacing pipeline segments greater than 1,000 feet in length is much greater than the cost of pressure testing. Furthermore, replacement costs are capitalized rather than expensed, compounding the impact on ratepayers over the life of the capital facilities.

The Applicants have a strong incentive to favor replacement and capitalization of costs instead of pressure testing and expensing costs. Capitalization increases return to shareholders. Consistent with that incentive, the Applicants are proposing to replace 94 percent of the high pressure distribution pipelines and 18 percent of the transmission pipelines that are included in

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[91] Tr. 1147-1148 (Applicants/Phillips).

[92] D.11-09-017, p. 22.

Phase 1.[93] The Applicants' proposed replacement projects can be efficiently reviewed on a case-by-case basis by adopting EAD procedures.

1. There should be case-by-case review of replacement projects because the direct cost of replacing pipelines is much more than the direct cost of pressure testing pipelines.

The direct cost of replacing pipelines is more than an order of magnitude greater than the direct cost of pressure testing pipelines. SCGC witness Yap testified that the cost of replacing transmission pipelines is on average $5.6 million a mile, 11 times greater than the average $0.5 million per mile cost of pressure testing pipelines. The direct cost of replacing high pressure distribution lines, which for purposes of the PSEP are considered to be transmission lines, is $3.4 million per mile, 16 times greater than the average $0.2 million per mile cost of pressure testing high pressure distribution pipelines.[94]

2. There should be case-by-case review of replacement projects because capitalizing the costs of pipeline replacements magnifies the burden of replacements on ratepayers.

Not only are the direct costs of replacing pipelines an order of magnitude greater than the direct cost of pressure testing pipelines. Capitalization of replacement costs magnifies the adverse impact of replacing pipelines on ratepayers. Capitalizing the costs increases the total cost to ratepayers over the life of the asset by about four times.[95] As shown by SCGC witness Yap, SoCalGas' proposed direct capital investment of $818 million in pipeline replacements and $301 million in valve addition/modification would result in SoCalGas ratepayers bearing a total revenue requirement of $4.2 billion over the life of the assets.[96] The return paid to investors and associated income taxes would increase the cost to ratepayers over the life of the assets by nearly

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[93] SCGC-1, pp. 809 (SCGC/Yap).

[94] Ex. SCGC-1, p. 5 (SCGC/Yap).

[95] SCGC-1, p. 6 (SCGC/Yap.

[96] *Ibid*.

$1.9 billion, and the Allowance for Funds Used During Construction ("AFUDC"), negative salvage, franchise fees, and property taxes would add nearly $1.3 billion. [97]

The impact of capitalizing costs is similar for SDG&E. SDG&E's proposed direct capital investment of $576 million in Phase 1 ($515 million of pipeline replacements and $61 million in valve additions/modifications) would result in a total revenue requirement of $2.4 billion over the life of the assets.[98] The return paid to investors and associated income taxes raise the cost to ratepayers by nearly $1.3 billion, while AFUDC, negative salvage, franchise fees, and property taxes add another $500 million over the life of the assets.[99]

3. There should be case-by-case review of replacement projects because the interests of ratepayers and shareholders conflict over the decision to replace rather than pressure test.

Capitalizing pipeline replacements would substantially expand the Applicants' rate bases. The expanded rate bases offer shareholders more return in future years.[100] Consequently, the Applicants have a strong incentive to replace pipelines rather than pressure test pipelines.[101]

Conversely, customers want safe pipelines at the lowest possible cost. Pressure-testing pipelines and replacing pipelines are equally effective in assuring that pipelines are safe.[102] Pipeline replacement increases the direct cost of ensuring pipeline safety by more than order of magnitude, and capitalizing the cost increases the total revenue requirement that is imposed upon ratepayers even more. Thus, customers have an economic interest that is the reverse of the shareholders' economic interest in deciding whether to replace or pressure test pipelines.

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[97] *Ibid*, p. 7.

[98] *Ibid*.

[99] *Ibid*.

[100] Ex. SCGC-1, p. 4 (SCGC/Yap).

[101] *Ibid*.

[102] *Ibid*.

There is no assurance that in making a decision about whether to replace rather than pressure test the pipeline the Applicants would take into account the long-term economic interest of ratepayers. Witness Phillips testified that in analyzing whether to replace rather than pressure test a pipeline segment, he would "look at the direct costs of pressure testing versus replacing."[103] When asked whether he would also consider "the rate consequences of capitalizing the direct cost of a capital project," he replied: "It's not something that I had considered."[104]

In Phase 1A, Applicants propose to spend $818 million in direct pipeline replacement costs for SoCalGas and another $197 million in direct pipeline replacement costs. For SDG&E they plan to spend another $318 million in direct costs in Phase 1B to replace Line 1600.[105] This $1.3 billion in direct capital pipeline replacement costs over Phases 1A and 1B would result in about $5.2 billion in pipeline replacement revenue requirement over the life of the assets.[106]

By contrast, the Applicants propose pressure testing in Phase 1A that would cost only $181 million for SoCalGas and less than $1 million for SDG&E.[107] The Applicants also proposed to pressure test Line 1600 during Phase 1B for a cost of $10 million.[108] If all of the Phase 1 pipeline validation work were done through pressure testing rather than replacements, the total O&M cost would increase by $59 million for SoCalGas and $51 million for SDG&E, but the entire $1.3 billion direct capital investment would be entirely eliminated.[109] Over the life of the assets, ratepayers would realize about $5.1 billion in savings if the Applicants pressure

[103] Tr. 1152 (Applicants/Phillips).

[104] *Ibid*.

[105] SCGC-1, pp. 3-4 (SCGC/Yap).

[106] *Ibid*, p. 4.

[107] *Ibid*.

[108] *Ibid*.

[109] *Ibid*.

tested rather than replace all of the transmission and high pressure distribution lines that the Applicants propose to replace during Phases 1A and 1B.[110] Conversely, shareholders would lose the benefit of the increased returns that would be realized if the replacement projects were pursued as proposed by the Applicants.

4. The case-by-case review should be done through expedited application docket proceedings.

The Applicants' witness Montgomery was asked "how do we provide an incentive to the utility diligently pursue the most cost effective…solution?" witness Montgomery responded: "It's oversight, reviewing the plans beforehand…."[111] Given the order of magnitude differential between the direct cost of pressure testing and the direct cost of replacing pipeline segments, and given that the direct costs of replacing pipeline segments are magnified by a multiple of four over the life of the assets by capitalizing the costs, each replacement project should be examined on a case-by-case basis to permit the effective oversight that was recommended by the Applicants' own witness Montgomery.

The question of whether a pipeline must be replaced turns in whether it is feasible to pressure test the pipeline.[112] The Applicants have many options they can pursue to avoid replacing a pipeline segment. SCGC witness Yap explained:

> [For] each pipeline, there is the potential that customer impacts could be sufficiently ameliorated to enable pressure testing. For example, during the engineering process, it may become apparent that it is possible to continue customer service for those downstream of the pipeline because a permanent crossover might be established to connect another portion of the system. A temporary line might be run around the section being pressure tested, or compressed or liquefied natural gas might be trucked in to feed regulation stations that deliver gas to the distribution

[110] *Ibid*.

[111] Tr. 717 (Applicants/Montgomery).

[112] SCGC-1, p. 10 (SCGC/Yap).

> system and that are normally fed by the line under pressure testing. Outages might be coordinated with the planned maintenance schedules for non-core customers. Alternatively, noncore customers may be willing to sustain an interruption of gas transmission service in return for compensation.[113]

To exercise effective oversight as recommended by Applicants' witness Montgomery, the Commission should review each replacement project on a case-by-case basis, requiring the Applicants to clearly identify each alternative that they evaluated in making a decision to replace rather pressure test a pipeline segment and to explain why the alternatives were found to be infeasible. The Commission should adopt a procedure for Phase 1A that would permit effective yet expeditious review of each proposal to replace a pipeline segment.

a. The expedited application docket procedure would permit effective yet expeditious review of replacement decisions.

D.92-11-052 provided an example of the type of procedure that would permit rapid yet effective review of replacement decisions. In D.92-11-052, the Commission established an "Expedited Application Docket" ("EAD") procedure for reviewing proposed contracts to avoid uneconomic bypass of the utility systems. In D.92-11-052, the Commission described the EAD procedure as follows:

> Applications for expedited review will be served on all parties to this proceeding, who will then have 30 days to protest the application. Responses to protests would be due within 10 days thereafter. The assigned administrative law judge will lead a workshop within 42 to 48 days of the application's filing date, after which time he or she will consult with the assigned commission to determine whether hearings are required. If no hearings are required, the Commission will endeavor to issue a decision within 75 days of the date of filing.[114]

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[113] SCGC-1, p. 11 (SCGC/Yap).

[114] D.92-11-052, 1992 Cal. PUC LEXIS 765, *9; 46 CPUC2d 444; 139 P.U.R.4^{th} 530 (November 23, 1992).

In more difficult cases where the proposal involved a contract rate that was below the class average marginal cost, the Commission provided for a slightly lengthened schedule:

> Where the contract rate is below the class-average LRMC, a different schedule will apply. Protests shall be filed and served within 45 days of the application's filing date and responses to protests will be due within 10 days thereafter. The workshop will be scheduled within 57 to 63 days of the application's filing date and the Commission will endeavor to issue a decision within 90 days of that filing date.[115]

The Commission also required utilities to submit responses to a Master Data Request to assure that the utilities submitted the information that would be needed to permit prompt and effective review of each contract.[116]

SCGC recommends adoption of the EAD procedure with, particularly, the use of a Master Data Request for review of the Applicants' decisions to replace rather than pressure test pipeline segments.

b. Cost estimates submitted in EAD proceedings should be based on no worse than Class 3 estimates.

The Applicants should be required to submit cost estimates in EAD proceedings that are no worse than Class 3 estimates and hopefully much better. The Association for the Advancement of Cost Engineering ("AACE") has established Cost Estimation Guidelines. The AACE establishes five classes of cost estimates ranging from Class 5, for which there is only a 2 percent project definition, to Class 1, for which there is a 50 to 100 percent project definition.[117] Witness Yap recommended that when submitting replacement projects for Commission review in EAD proceedings, the Applicants should be required to support their project proposals with at

[115] *Ibid*.

[116] SCGC-1, p. 12 (SCGC/Yap).

[117] SCGC-1, p. 26 (SCGC/Yap).

least Class 3 estimates, which provide a 10 percent to 40 percent level of project definition and an estimate accuracy range of minus 20 percent to plus 30 percent.

The Applicants should strive, however, to submit better estimates. A Class 2 estimate would have an accuracy range of minus 15 percent to plus 20 percent, and a Class 1 estimate would have an accuracy range of minus 10 percent to plus 15 percent.[118]

c. The Commission should adopt a cost cap for each replacement project approved in an EAD proceeding.

For Phase 1A, the Applicants would have little incentive to control costs if the cost overrun would simply be added to the balance in their proposed PSEPCRA.[119] To overcome the lack of incentive to control costs, the Commission should adopt a cost cap for each pipeline replacement project that is approved through the EAD process. The Applicants' replacement project estimate, if approved in the EAD proceeding, would provide the basis for the cost cap.[120] As long as the Applicants' recorded pipe replacement cost did not exceed the cost cap, the revenue requirement associated with the capital investment in the pipeline replacement would be permitted to be recorded in the PSEPCRA. Costs that exceed the cap should not be permitted to be recovered absent a reasonableness review.[121]

5. The number of EAD proceedings would be manageable.

The Applicants' primary objection to case-by-case review of the Applicants' Phase 1A replacement decisions is that it would add "hundreds of new applications to the Commission's already burdened docket…."[122] The Applicants are wrong. There would not be "hundreds of new applications." Applicants' witness Rivera identified the projected replacement projects for

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[118] *Ibid*.

[119] SCGC-1, p. 27 (SCGC/Yap).

[120] *Ibid*.

[121] *Ibid*, pp. 27-28.

both SoCalGas and SDG&E his workpapers.[123] His workpapers identify 135 Phase 1A replacement projects, excluding Line 1600 which is deferred to Phase 1B.[124] That is far less than the "hundreds" about which witness Rivera complained in his rebuttal testimony.

Furthermore, witness Rivera's workpapers overstated the number of replacement projects. The workpapers were dated December 2, 2011.[125] Subsequently, on January 13, 2012, the Applicants submitted Comments in Response to Assigned Commissioner's Rulings and Supplement to Request for Memorandum Account ("January 13, 2012 Comments") in both R.11-02-019 and A.11-11-002. The January 13, 2012 Comments contained an Attachment A that presented the Applicants' proposed Phase 1A projects, including both hydro testing projects and replacement projects.[126] Five of the replacement projects that were included in Mr. Rivera's December 2, 2012 workpapers were identified in Attachment A with a note stating: "Scope no longer in Phase 1A."[127] The five pipelines associated with the note were pipeline 35-6405BR1, pipeline 5009, pipeline 1019BP1, pipeline 1170 ID502-T 1, and pipeline 1171 ID567-P 13. All were SoCalGas pipelines. Additionally, Mr. Reyes December 2, 2011 workpapers included two SDG&E pipelines, pipeline 49-19 and pipeline 49-20, that were listed in Attachment A to the January 13, 2012 Comments with a note stating: "Scope being addressed independent of PSEP." If the five SoCalGas pipelines and the two SDG&E pipelines are excluded from witness Rivera's list of replacement projects, the number of replacement projects to be pursued in Phase 1A drops from 135 to 128 projects.

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[122] Ex. SCGC-26, p. 7 (Applicants/Reyes).

[123] Ex. SCG-32, pp. WP-IX-1-23 through WP-IX-1-37; SCGC-4.

[124] SCGC-4, p. WP-IX-1-34 ("The pipeline replacement project for Line 1600 is expected to span both Phase 1A and Phase 1B. It is estimated that approximately 4% of the total costs will occur in Phase 1A (2012-2015) and the remaining 96% of the costs will occur in the first three years of Phase 1B (2016-2018)").

[125] Tr. 1328 (Applicants/Rivera).

[126] January 13 Comments, p. 7.

The number of replacement projects in the PSEP for Phase 1A will decrease further if, as recommended by SCGC, the Commission determines that the Applicants' shareholders rather than ratepayers shall be responsible for remediation of post-1961 pipeline segments. The number of replacement projects in the PSEP for Phase 1A may decrease even further as a result of the Applicants' continuing search for pressure test records[128] or as a result of the Applicants deciding on their own to pressure test rather than replace pipeline segments.

Even if the number of replacement projects does not decrease further, 128 EAD applications would be manageable.

First, not all the applications would be submitted at the same time. Witness Phillips estimated that "the engineering part has to get done within the first probably two years, maybe three on some projects."[129] Thus, the submission of EAD applications to pursue replacement projects would be spread over two or three years and possibly longer.

Second, it is likely that the first projects that would be submitted through EAD applications would be scrutinized more closely, with subsequent applications being processed more routinely. In describing the review of replacement projects by the Engineering Advisory Board that the Applicants propose in their rebuttal testimony, witness Phillips said that "my belief is after we do a dozen or so projects with the board, if we run through the details in the first dozen or so projects with the board, we may not need to get into as great a detail for the following projects."[130] The same is likely to be true of EAD applications.

Contrary to the laments of the Applicants, processing the Applicants' EAD applications for replacement projects would not overburden the Commission.

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[127] January 13 Comments, Attachment A, p. 6.

[128] Tr. 415 (Applicants/Schneider) ("were still going through records review").

[129] Tr. 1192 (Applicants/Phillips).

6. Reviewing replacement projects through the EAD process would not unduly delay work on the PSEP.

Applicants' witness Phillips complained that adopting the EAD process for reviewing replacement projects would result in "slowing down progress on an already ambitious schedule."[131] Unfortunately, witness Phillips ventured his opinion without becoming informed about the EAD process. He admitted to his lack of familiarity with the process:

> Q: Are you familiar with the expedited application docket procedure as previously used at the Commission:
>
> A: Not extensively, no.
>
> Q: Are you familiar with the fact that there was a master data request so that upfront the Commission would be getting detailed information so that we wouldn't be going through a long discovery process?
>
> A: No, I'm not.
>
> Q: Are you familiar with the time frame that the Commission set for acting upon expedited application docket applications as that procedure was previously used at the Commission?
>
> A: No, I'm not.[132]

The EAD process as described above would result in prompt processing of applications to pursue Phase 1A replacement projects without "slowing down progress" as claimed by witness Phillips.

Likewise, the need for the Applicants to prepare materials for submission to the Commission for EAD consideration would not result in "slowing down progress on an already ambitious schedule." Witness Phillips proposed an Engineering Advisory Board in his rebuttal testimony to review replacement decisions.[133] He admitted that the information that the

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[130] Tr. 1193 (Applicants/Phillips).

[131] Ex. SCG-20, p. 16 (Applicants/Phillips).

[132] Tr. 1190 (Applicants/Phillips).

[133] Ex. SCG-20, p. 14 (Applicants/Phillips).

Applicants would provide to the Engineering Advisory Board would be about the same as what would be presented to the Commission through the EAD process:

> Q: What are you planning to have presented to the board then? Is it substantially less than what you would envision submitting to the Commission under the EAD process?
>
> A: Well, it is probably pretty close to the same.[134]

If it would be acceptable to the Applicants to prepare material for review by their proposed Engineering Advisory Board, it should be acceptable to the Applicants to prepare the information for review by the Commission through the EAD process.

In any event, the Applicants are the last ones who should complain about "slowing down progress." The Commission has not permitted the Applicants to start recovering costs booked into their PSRMA, so they are obviously moving slowly with PSEP work until they can start recovering revenues through their proposed PSEPCRA.

The PSRMA became effective on May 20, 2012.[135] According to Applicants' witness Buczkowski, the hydro testing project that has "advanced the furthest" is the hydro testing of Line 2000."[136] There are "six other hydro test projects," but "they haven't commenced."[137] Likewise, the Applicants have not yet contracted with a program management contractor, although they are "targeting November."[138]

Perhaps the best example of how the Applicants are moving slowly is that they waited until the PSRMA became effective to commence the twelve-month period for conducting the activities identified in their January 13, 2012 Comments. Witness Buczkowski testified that the

[134] Tr. 1192 (Applicants/Phillips).

[135] ?

[136] Tr. 885 (Applicants/Buczkowski).

[137] *Ibid*.

[138] Tr. 887 (Applicants/Buczkowski).

twelve months for which work was projected in the January 13, 2012 Comments was a "floating twelve-month period" which would only commence when the advice letters proposing the Applicants' PSRMAs were approved.[139] Given that the PSRMAs became effective on May 20, 2012, the twelve-month period will now extend to May, 2013.[140]

Not only was the work projected in the January 13, 2012 Comments delayed until the PSRMAs became effective on May 20, 2013. When Mr. Buczkowski was asked whether the Applicants were on track to accomplish the milestones identified in the "Notes" column in Attachment A to the January 13, 2012 Comments, witness Buczkowski replied that the Applicants are "probably not on the schedule for meeting these milestones."[141] When asked about the "percentage chances" that by May, 2013, the Applicants would have achieved the goals established in the "Notes" column in Attachment A to the January 13, 2012 Comments, witness Buczkowski said: "I don't have that number."[142]

Adopting an EAD process to assure the sort of effective oversight that Applicants' witness Montgomery recommended to assure the appropriateness of replacement projects would certainly not slow progress on the PSEP any more than progress has already been slowed by the Applicants waiting for Commission approval of cost recovery mechanisms.

7. The Engineering Advisory Board that the Applicants propose as an alternative to the EAD process would be inadequate.

The Engineering Advisory Board that the Applicants propose in their rebuttal testimony to counter the EAD recommendation is wholly inadequate to protect ratepayer interests. The Applicants' describe the Engineering Advisory Board as follows:

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[139] Tr. 889 (Applicants/Buczkowski).

[140] *Ibid*; Tr. 892 (Applicants/Buczkowski).

[141] Tr. 896 (Applicants/Buczkowski).

[142] Tr. 897 (Applicants/Buczkowski).

> This Engineering Advisory Board would be a four member board made up of a company representative, a representative of the CPUC's Consumer Protection and Safety Division (CPSD), a representative of the CPUC's Energy Division, and an outside pipeline integrity expert to be mutually agreed upon by the first three. This advisory board will review and provide input on SoCalGas and SDG&E's test re replace decisions and its accelerated mileage decisions.[143]

The inadequacies of the Engineering Advisory Board are multiple and manifold.

First, as its name connotes, the Engineering Advisory Board would focus on engineering instead of the rate-related need to avoid replacement projects to the maximum extent possible to mitigate the impact on ratepayers. Consequently, there would be no rate advocates on the Board. Applicants' witness Morrow admitted: "It was not intended to include the rate advocates on the board. This is more of an engineering review board…."[144]

Second, the Board would be dominated by the Applicants themselves. Rather than proposing an independent board that would be selected, for example, by the Commission or by stakeholders, the Applicants will have a seat on the Board. Furthermore, the Board will have only four members, with the Applicants participating in picking the fourth member. Given that the Commission's Consumer Products Safety Division ("CPSD") is not focused on costs or rate impact issues, there would be only one member of the Board, the Energy Division, which is likely to be focused on the rate-related need to minimize adverse revenue requirement impacts of replacement decisions.

Third, the operations of the Board would be completely opaque to the public. Although Applicants' witness Morrow admitted to the need to "provide additional transparency to respond to Intervenor requests for more information on how we're going to manage the process of the

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[143] Ex. SCG-20, p. 15 (Applicants/Phillips).

[144] Tr. 147 (Applicants/Morrow).

replacements and the hydro testing,"[145] there would be no opportunity for public participation in the deliberations of the Board by stakeholders.[146] Likewise, reports given to the Board would not be made public unless the Commission intervened to make documents public.[147]

Fourth, the Board will be powerless. If, in spite of the domination of the Board by the Applicants, the Board failed to confirm the Applicants' decisions about whether to replace rather than pressure test a pipeline segment, the Applicants could proceed with replacements without regard to the opinion of the Board.[148]

Fifth, the Board is made up of an even number of members, leading to the possibility of tie votes.

V. REASONABLENESS OF COST ESTIMATES.

The Applicants present forecasts of annual PSEP costs that the Applicants propose to use to calculate their proposed PSEP Surcharge.[149] The Applicants' cost estimates are so wildly inaccurate that they are arbitrary. The estimates are totally inappropriate for setting rates that will actually be paid by ratepayers.

Applicants' witness Buczkowski acknowledges that the estimates presented in the Applicants' PSEP application "are necessarily preliminary and often somewhat conceptual in nature.[150] Witness Buczkowski says the Applicants "recognize that cost estimates will necessarily require further refinement."[151] Witness Buczkowski says in his rebuttal testimony

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[145] Tr. 148 (Applicants/Morrow).

[146] Tr. 151 (Applicants/Morrow).

[147] Tr. 153 (Applicants/Morrow).

[148] Tr. 1181 (Applicants/Phillips).

[149] Tr. 1576 (Applicants/Reyes).

[150] Ex. SCG-21, p. 2 (Applicants/Buczkowski).

[151] *Ibid*.

that the cost estimates in the PSEP application are "Class 5 estimates."[152] On cross examination he characterized the estimates as being "between 4 and 5."[153]

According to the Association for the Advancement of Cost Engineering ("AACE") classification methodology, Class 5 estimates have an expected accuracy range of minus 50 percent to plus 100 percent.[154] Class 4 estimates have an expected accuracy range of minus 30 percent to plus 50 percent.[155] Even if the estimates can be classified as "between 4 and 5," that means they have an accuracy range of minus 40 percent to plus 75 percent, which is not much improvement over Class 5 estimates.

Applicants' witness Buczkowski could provide no examples of any instance of rates being set on the basis of Class 5 or Class 4 estimates.[156] In his testimony, witness Buczkowski pointed to Advanced Metering Infrastructure ("AMI") programs as instances in which the Commission adopted forecasted revenue requirements to be included in gas transportation rates. Particularly, witness Buczkowski cited the Pacific Gas & Electric Company ("PG&E") proceedings in A.05-06-028.[157] However, witness Buczkowski admitted that instead of including a revenue requirement in rates that was based upon a Class 5 or between Class 4 and 5 estimates, PG&E "had a more defined project definition" so that the estimates were "better than Class 4."[158] Also, witness Buczkowski admitted that PG&E included an 8 percent contingency in their revenue requirement estimate,[159] indicating the AMI project had a much higher level of

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152 *Ibid*.

153 Tr. 881 (Applicants/Buczkowski).

154 Ex. SCGC-1, p. 26 (Chart 1:AACE Classification Methodology) (SCGC/Yap).

155 *Ibid*.

156 Tr. 1037 (Applicants/Buczkowski).

157 Ex. SCG-21, pp. 15, 18.

158 Tr. 882 (Applicants/Buczkowski).

159 *Ibid*.

project definition than the 0 to 2 percent level of definition associated with Class 5 estimates or the 1 percent to 15 percent level of definition associated with Class 4 estimates.[160]

Insofar as the Applicants' estimates are Class 5 estimates or between Class 4 and Class 5 estimates, they are wholly unreasonable, arbitrary, and capricious as a basis for establishing a surcharge that would appear on bills to the Applicants' ratepayers. The cost estimates should be rejected as a basis for calculating the PSEP Surcharge.

VI. ALTERNATIVES TO REPLACEMENT OR PRESSURE TESTING.

The Commission should carefully consider the Applicants' proposed alternatives the replacement and pressure testing. In D.11-06-017, the Commission ordered the Applicants "to comply with the requirement that all in-service gas transmission pipeline in California has been pressure tested in accord with 40 CFR 192.619, excluding subsection 49 CFR 192.619(c)."[161] By requiring the Applicants to comply with 49 CFR 192.619 excluding subsection 49 CFR 192.619(c), the Commission eliminated the ability of the Applicants to rely on the "grandfather clause" in 49 CFR 192.619(c). The "grandfathering clause" provides that the MAOP of a transmission pipeline may be established on the basis of the highest actual operating pressure to which the pipeline was subjected during the five-year period preceding November 12, 1970:

> (c) Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, subject to the requirements of §192.611.[162]

The Applicants interpreted in D.11-06-017 to mean that they would need to test or replace all pipeline segments that do not have sufficient documentation of pressure testing to satisfy

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[160] SCGC-1, p. 26 (Chart 1:AACE Classification Methodology) (SCGC/Yap).

[161] D.11-06-017, p. 31 (Ordering Paragraph 4).

[162] 49 CFR §192.619(c).

"modern standards."[163] The Applicants understand the term "modern standards" to mean 49 CFR Part 192, Subpart J,[164] as it appears in today's Code of Federal Regulations.[165]

Bringing all pre-1970 pipelines to "modern standards," meaning today's 49 CFR Part 192, Subpart J, would be costly. For example, even though a pipeline was pressure tested in 1962 in accordance with General Order No. 112 and immaculate records were retained by the Applicants, the pipeline would have to be re-tested if, for example, there were no record of testing for eight hours.[166] One hour was all that was required by General Order No. 112 in 1962. Furthermore, the records test would have to meet the detailed requirements of 49 CFR 192.517 rather than the less detailed requirements of General Order No. 112.

As an alternative to eliminating the "grandfathering clause" and requiring that all pipelines be tested to the "modern standards" of the current version of 49 CFR Part 192, the Applicants propose that the "grandfathering clause" be retained as part of General Order No. 112-E but that California regulations be strengthened by requiring that transmission pipelines be required to meet one of four conditions that are specifically targeted at validating the stability of pipeline long seams.[167] The "grandfathering clause" would still be used to establish a pipeline's MAOP,[168] but applying one of the four alternative conditions as discussed below would assure the safety of the pipeline.

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[163] Ex. SCG-02, p. 18 (Applicants/Morrow).

[164] Tr. 160 (Applicants/Morrow).

[165] Tr. 311-312 (Applicants/Schneider).

[166] Tr. 305 (Applicants/Rosenfeld).

[167] Ex. SCG-04, pp. 45-46.

[168] Tr. 426 (Applicants/Schneider).

A. Alternative 1: Post Construction Strength Test to at Least 1.25 Times MAOP.

The Applicants' first alternative would require a post-construction strength test to at least 1.25 times MAOP with different recordkeeping and testing requirements applying to pre-November 12, 1970 pipelines and post-November 11, 1970 pipelines:

> 1. A post construction strength test to at least 1.25 MAOP; this pressure test shall:
>
> a) For pipe pressure tested before November 12, 1970, provide records of the test medium and test pressure.
>
> b) 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.[169]

Under clause 1(a), pipelines that were pressure tested prior to November 12, 1970, would not be required to be retested for an eight hour duration as would be required 49 CFR Subpart J. Additionally, the records of pressure testing would not have to meet the detailed requirements of Subpart J. The records would only have to include the elements required by the regulations that were in effect at the time the test was conducted. That would be consistent with D.11-09-017, which ordered: "A pressure test must include all elements required by the regulation in effect when the test was conducted."[170] Conversely, under clause 1(b), the post-November 11, 1970 pipelines would be required to be tested for eight hours and would be required to have a detailed record specified in 49 CFR 192.517.

The first alternative would require pressure testing of pipelines in all areas including Class 1 areas to at least 1.25 times MAOP. 18 CFR 192.619(a)(2) only requires that pipelines in

[169] Ex. SCG-04, p. 46 (Applicants/Schneider).

[170] D.11-09-017, p. 31 (Ordering Paragraph 3).

Class 1 areas be tested to 1.1 times MAOP.[171] Witness Schneider explained that testing pipelines in all areas including Class 1 areas to at least 1.25 times MAOP would be appropriate because 1.25 times MAOP is the "stability threshold" for long seams:

> So you know, again, post-San Bruno, you know, we want to – we wanted to identify and target where we needed to work on our system. And so there's industry papers and information that talk about 1.25 times the MAOP being the stability threshold for the long seams and the fact that a long seam is what failed at San Bruno.[172]

SCGC recommends that the Commission allow the Applicants to use Alternative 1 as an alternative to bringing all pipelines including pipelines that were pressure tested before November 12, 1970, to the "modern standards" in 49 CFR Part 192. Permitting the Applicants to use Alternative 1 to validate long seams could save millions of dollars that would otherwise have to be spent, particularly in Phase 2, to re-test or replace pipelines that have already been pressure tested while simultaneously imposing an appropriately more stringent requirement for Class 1 areas.

B. Alternative 2: Lowering the MAOP to Less than or Equal to 72 Percent of the Highest Documented Actual Operating Pressure.

The second condition would apply only to pre-November 12, 1970 pipelines:

> 2. For pipelines placed in service prior to November 12, 1970 the MAOP shall have been lowered to a value ≤72 percent of the highest actual operating pressure documented during the 5 years preceding the pressure reduction.[173]

A reduction of MAOP to less than or equal to 72 percent of the actual highest operating pressure is equivalent to a safety factor of 1.39 times MAOP, which is the next value higher than 1.25

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[171] 49 CFR §192.619(a). If the design pressure is lower than the test pressure divided by 1.1, or if the operator determines that due to corrosion or other factors the pipeline should be operated at a lower pressure, that lower pressure will determine the MAOP.

[172] *Ibid* p. 46.

[173] Ex/ SCG-04, p. 46 (Applicants/Schneider).

times MAOP under the American Society of Mechanical Engineers ("ASME") B31.8S standard.[174] Requiring "in-service" pressure testing to 1.39 times MAOP would "account for the fact that operational pressure measurements are not static and portions of the pipeline may not have experienced the measured highest pressure."[175] The requirement that the pressure reduction be applied to the maximum operational pressure experienced during the preceding five years would alleviate concerns about the MAOP being set above pressures that the pipelines have recently experienced.[176]

In his direct testimony the Applicants' witness Schneider suggested that the Commission could consider his second alternative condition "in the next phase of this proceeding."[177] However, he recognizes that permitting pressure reductions to less than or equal to 72 percent of MAOP "could potentially reduce pipeline safety enhancement plan implementation costs for our customers."[178] Thus, he observed that "if we could address it sooner, then it could be used as an alternative in this first phase."[179]

Permitting the Applicants to use Alternative 2 as an alternative to pressure testing pipeline segments for which the Applicants lack sufficient documentation of pressure testing could save millions of dollars in Phase 1A a well as in Phase 2. The Commission should consider Alternative 2 in this proceeding and permit Alternative 2 to be applied in Phase 1A of the PSEP.

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[174] *Ibid*, Footnote 37.

[175] Ex. SCG-04, p. 59 (Applicants/Schneider).

[176] *Ibid*.

[177] Ex. SCG-04, p. 60 (Applicants/Schneider).

[178] *Ibid*.

[179] Tr. 36 (Applicants/Schneider).

C. Alternative 3: Non-Destructive Examination.

Witness Schneider's Alternative 3 would permit non-destructive examination of pipelines to validate the stability of the long seam:

> 3. A complete non-destructive examination using an inspection method capable of seam anomaly detection, and subsequent remediation of seam defects with predicted failure pressures ≤ 1.39 times MAOP.[180]

Non-destructive examination utilizes ultrasonic, radiographic, and magnetic particle inspection techniques.[181] Witness Schneider proposed Alternative 3 particularly as an alternative to replacing and abandoning short segments of pipeline.[182] Using non-destructive examination of short segments would "reduce the time, cost, customer impact, and construction hazards associated with replacement."[183] Additionally, non-destructive examination would have the benefit of providing additional information that pressure testing cannot provide, such as information about coating condition, corrosion, and other subcritical defects that could not be detected through a pressure test.[184]

An additional benefit of non-destructive examination is that, in general, it would be expensed rather than capitalized. If the non-destructive examination alternative is not approved, SoCalGas proposes to replace rather than pressure test short pipeline segments. As discussed above, replacement costs are capital costs that increase the total revenue requirement burden on customers fourfold above direct costs over the life of the asset.[185] Non-destructive examination rather than replacement of short segments would reduce the direct cost of short segment projects

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[180] Ex. SCG-04, p. 46 (Applicants/Schneider).

[181] *Ibid*.

[182] *Ibid*, p. 54.

[183] *Ibid*.

[184] *Ibid*.

[185] Ex. SCGC-1, p. 14 (SCGC/Yap).

by approximately $5-50 million.[186] Given that the direct costs of replacement would be capitalized, the total savings over the life of the asset for ratepayers would be much greater.

The Applicants' proposal to remediate seam defects that non-destructive examination shows to have a predicted failure pressure of less than or equal to 1.39 times MAOP provide an extra margin of safety in comparison to testing to 1.25 times MAOP.

Given the multiple benefits than could be realized if non-destructive examination were permitted as an alternative to pressure testing or replacing, particularly, short pipeline segments, SCGC recommends that the Commission approve the Applicant's proposed Alternative 3 in this proceeding for use in Phase 1A.

D. Alternative 4: Transverse Field Inspection.

Although witness Schneider's first three alternative conditions should be considered and approved in this proceeding so that, particularly, Alternatives 2 and 3 will be available to be used in Phase 1A, witness Schneider's fourth alternative would have to be considered by the Commission in the Applicants' Test Year 2016 for application during Phase 1B and Phase 2 of the PSEP as an alternative to pressure testing or replacing pipeline segements. Witness Schneider's fourth alternative is as follows:

> Once transverse field magnetic flux leakage in-line inspection has been expressly validated by order of the Commission, an in-line inspection using a transverse field inspection tool followed by validation using non-destructive evaluation methods capable of seam anomaly detection, and remediation of seam defects with predicted failure pressures less than or equal to 3.39 times MAOP.[187]

[186] *Ibid*, p. 15.

[187] Ex. SCG-04 (Applicants/Schneider).

TFI is uniquely appropriate for determining the safety of long seams: "[TFI] magnetizes the pipe in a way that you can look for cracks and specifically cracks in long seam in this case."[188]

The Applicants propose to use TFI during Phase 1A prior to pressure testing pipelinto gather data so that the Applicants can demonstrate that TFI can provide reliable validation of long seam integrity.[189] Witness Schneider said: "The signs support it and said it is very promising, but we want to prove it up."[190]

The Commission should permit the Applicants to use TFI during Phase 1A for the express purpose of presenting data to "prove it up" in the Applicants' Test Year 2016 GRC. If the Applicants are successful in "proving up" TFI and the Commission permits TFI testing as an alternative to pressure testing or replacement, there could be substantial savings in Phases 1B and 2 of the PSEP: "The TFI technique could save billions in revenue requirement during Phases 1B and 2 of the PSEP."[191] Particularly, TFI could be used to inspect Line 1600, potentially obviating the need to replace the existing 16-inch Line 1600 with a new 36-inch pipeline as contemplated by the Applicants for Phase 1B and obviating the need to subsequently pressure test Line 1600.

There are additional benefits of permitting the Applicants to utilize TFI during Phase 1A. First, conducting the TFI procedure in advance of pressure testing in Phase 1A would potentially alert the operators to pipeline defects which could then be repaired prior to pressure testing to

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[188] Tr. 445 (Applicants/Schneider).

[189] Tr. 446 (Applicants/Schneider).

[190] *Ibid*.

[191] SCGC-1, p. 17 (SCGC/Yap).

avoid failure of the pipeline during pressure testing.[192] Second, the TFI procedure would allow pipeline operators to spot small cracks that might not even show up during pressure testing.[193]

In order to realize both the short term benefits of TFI and the potential longer term benefit of being able to use TFI as an alternative to pressure testing or replacing pipelines, SCGC recommends that the Commission approve the Applicants' proposal for use TFI prior to pressure testing Category 4 pipeline segments in Phase 1A.

VII. REVENUE REQUIREMENTS.

The Applicants propose forecasted revenue requirements for each year of the PSEP starting with 2011 for both SoCalGas and SDG&E.[194] The Applicants also propose to establish Pipeline Safety Enhancement Plan Cost Recovery Accounts ("PSEPCRAs") for SoCalGas and for SDG&E as interest bearing balancing accounts.[195] The Applicants propose to record actual O&M expense and actual capital-related revenue requirements associated with implementing the PSEP as debit entries,[196] and they propose to record actual revenues recovered through the PSEP Surcharge as credit entries.[197] The Applicants propose to charge a PSEP Surcharge each year that would be calculated to collect the annual forecasted revenue requirement for the year plus the balance accumulated in the PSEPCRA during the previous year.

The Applicants' forecasted annual revenue requirements should not be used to set the PSEP Surcharge either for the first year that the PSEPCRA is in effect or for any subsequent year. The Applicants' revenue requirement forecasts are too uncertain to be used as a basis for the PSEP Surcharge, even assuming same later adjustment through an advice letter. The

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[192] SCGC-1, p. 16 (SCGC/Yap).

[193] *Ibid*, p. 17.

[194] Ex. SCG-10, pp. 124-125 (Applicants/Reyes).

[195] Ex. SCG-10, p. 126 (Applicants/Reyes).

[196] *Ibid*.

Applicants' forecasts of PSEP annual revenue requirements are so imprecise that they should be regarded as informational only and not used for any rate-setting purpose. The Commission should only allow the Applicants to recover actually incurred costs.

A. Proposed Revenue Requirements.

The Applicants' forecasts as presented in their direct testimony are based upon inaccurate estimates, include projects that will not occur, include projects that should not be ratepayer-funded, and are out of date.

1. The Applicants' forecasts are based upon highly inaccurate estimates.

The forecasts of annual revenue requirement that Applicants' witness Reyes presents in his direct testimony are based on highly inaccurate estimates. Witness Reyes, himself, admits to the inaccuracy of the estimates: "Costs estimates are preliminary and were developed based on minimal engineering, operational planning, and project execution planning."[198] The Applicants' witness Buczkowski agrees: "SoCalGas and SDG&E acknowledge that these estimates are necessarily preliminary and often somewhat conceptual in nature."[199] The Applicants admit that their "cost estimates will necessarily require refinements and updates" and are "Class 5 estimates."[200]

On cross-examination witness Buczkowski tried to argue that the Applicants' estimates are "between 4 and 5."[201] That is little solace. Class 5 estimates have an expected accuracy range of minus 50 percent to plus 100 percent.[202] Class 4 estimates have an expected accuracy

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[197] *Ibid*.

[198] Ex. SCG-09, p. 103 (Applicants/Reyes).

[199] Ex. SCG-21, p. 2.

[200] *Ibid*.

[201] Tr. 881 (Applicants/Buczkowski).

[202] SCGC-1, p. 26 (SCGC/Yap).

range of minus 30 percent to plus 50 percent.[203] Thus, estimates that are between Class 4 and Class 5 have an expected accuracy range of minus 40 percent to plus 75 percent. That is too inaccurate to provide a basis for ratemaking. As discussed above, the Applicants have failed to produce any example of the Commission using such inaccurate estimates as the basis for setting rates that would actually be charged to customers.

2. The Applicants' forecasts include projects that will not be pursued or should not be ratepayer-funded.

The Applicants' PSEP estimates include projects that will not be pursued. Witness Rivera developed the Applicants' PSEP estimates. As discussed above, he included in his workpapers seven projects that Applicants subsequently identified as "scope no longer in Phase 1A" or "scope being addressed independent of PSEP" in Attachment A to the January 13, 2012 Comments.

Also, the PSEP estimates include the cost of pressure testing or replacing pipeline segments that were constructed between 1961 and 1970. As discussed above, shareholders rather than ratepayers should be required to bear the cost of pressure testing or replacing the 1961-1970 vintage pipelines. The Applicants' annual estimates are erroneous to the extent that they include costs that should be disallowed for rate recovery.

3. The Applicants are so far behind schedule that their annual forecasts are out-dated.

The Applicants are so far behind schedule in pursuing their projected PSEP projects that the annual estimates in their direct testimony are out-dated. For example, in his direct testimony witness Reyes forecasted that SoCalGas would incur direct costs of $6 million in 2011 and $219 million in 2012 under the Applicants' Proposed Case and would incur direct costs of $6 million in 2011 and $168 million in 2012 under the Applicants' Base Case. However, by the time of the

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[203] *Ibid*.

hearing in this proceeding in August, 2012, SoCalGas had recorded no capital costs in its PSRMA and, as of June, 2012, "O&M expense somewhere in the ballpark of $10.5 million."[204] $10.5 million is far short of the $30-40 million that would be expected to be recorded in the SoCalGas PSRMA by August, 2012, given the forecasts of 2012 revenue requirements that were presented in the Applicants' witness Reyes's direct testimony.[205]

4. Inaccurate revenue requirement forecasts cannot be reasonably cured through an advice letter update.

The forecasts of revenue requirements that are contained in the Applicants' direct testimony are based on estimates that are so wildly inaccurate, erroneous, and outdated that they cannot be cured through an updating advice letter as proposed in the Applicants' direct testimony.[206] Any revenue requirement forecast that would be presented in an advice letter that would be filed sometime in 2013 would have no reasonable relation to the annual revenue requirement forecasts presented in the direct testimony of witness Reyes.

B. Intervenor Proposals Relating to Revenue Requirements.

As discussed below, upon Commission approval of the Applicants' PSEPCRAs, the Applicants should be permitted to commence debiting their PSEPCRAs with actually incurred PSEP O&M expenses and actually incurred PSEP capital-related revenue requirement on a monthly basis. If by that time the Commission has reviewed and approved amounts that are recorded in the Applicants' PSRMAs, the Applicants should be permitted to start charging a PSEP Surcharge that recovers reviewed and approved PSRMA balances, with the resulting revenues being credited to the PSEPCRA on a monthly basis. The PSRMA balances would

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[204] Tr. 1550 (Applicants/Reyes).

[205] Ex. SCG 10 (Applicants/Reyes).

[206] Ex. SCG-10, p. 126 (Applicants/Reyes).

constitute the "year one" revenue requirement recovered through the PSEP Surcharge with PSEP Surcharge revenues being credited to the PSEPCRA.

For succeeding years the revenue requirements that are recovered through the Applicants' PSEP Surcharges should be the revenue requirements underlying the Applicants' PSEP Surcharges for the previous year adjusted to by the amount of the balances accrued in the PSEPCRAs during that year. The Applicants should not be permitted to use any forecasted revenue requirement to calculate the PSEP Surcharge.

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

There are some points of agreement between SCGC and the Applicants about recovery of Phase 1A PSEP costs. SCGC and the Applicants agree that the Applicants should be permitted to maintain their PSEPCRAs as an interest bearing balancing accounts and that year-end balances in the accounts should be amortized through the Applicants' PSEP Surcharges. SCGC and the Applicants also agree that expenses and capital-related costs should be debited to the PSEPCRAs, although it is unclear that there is agreement about the timing for commencing debiting of a project's capital-related costs to the PSEPCRAs, and SCGC and the Applicants agree that revenues recovered through the PSEP Surcharges should be credited to the PSEPCRAs.

SCGC and the Applicants disagree, however, about the structure of the PSEPCRAs, the calculation that the PSEP Surcharges, and the termination of the PSEP Surcharges after the Applicants' Test Year 2016 GRC.

A. PSEP Cost Recovery Account.

The Applicants should be permitted to implement their PSEPCRAs after the Commission issues its decision in this proceeding. After implementation, expenses should be recorded on a monthly basis as they are incurred, and capital-related costs should be recorded on a monthly basis starting when the underlying facilities become used and useful. Separate accounts should be maintained for expenses and capital-related costs. The PSEPCRA year-end balances should be amortized through the Applicants' PSEP Surcharges, with the PSEP Surcharges being adjusted annually through the Applicants' customary Annual Regulatory Account Balance Updates. The Applicants' PSEPCRAs and PSEP Surcharges should be terminated after PSEP costs are integrated into the Applicants' base margins in the Applicants' Test Year 2016 GRC.

1. The capital-related revenue requirement for a project should be debited to the PSEPCRA only after the underlying project becomes used and useful.

Although it appears that the Applicants agree with SCGC witness Yap that actual PSEP expenses should be debited to the PSEPCRA on a monthly basis, the Applicants' position on debiting capital-related costs to the PSEPCRA is unclear. Capital-related revenue requirement associated with specific pipeline replacements and valve installations should be recorded on a monthly basis in the PSEPCRA only after the underlying facilities become used and useful and are placed in service.[207] Pipeline replacement projects and valve installations should be permitted to accrue Allowance for Funds Uses During Construction ("AFUDC") until the underlying facilities become used and useful.[208]

Debiting capital-related costs to the PSEPCRA only after the underlying facility becomes used and useful follows the precedent established by the Major Additions Adjustment Clause ("MAAC") that was adopted for Southern California Edison Company ("SCE") during the late 1980s to permit interim recovery of capital-related revenue requirements for a series of projects that were brought into service between SCE general rate cases.[209] In the absence of the MAAC

[207] SCGC-1, p. 24 (SCGC/Yap).

[208] *Ibid*.

[209] D.87-12-066, 1987 Cal. PUC LEXIS 415; 26 CPUC2d 392 (December 22, 1987), Appendix A at *115.

procedure, if a utility brought a major plant addition into service between general rate cases, the utility would no longer accrue AFUDC on the plant addition, but it would be unable to reflect the cost of the plant addition in revenue requirement until the following general rate case proceeding, resulting in a loss in earnings.

The Applicants' apparent lack of specificity about whether capital related costs would be debited to the PSEPCRA only after a project becomes used and useful is probably due to the fact that the Applicants, unlike SCE with the MAAC, propose not to rely on debiting actual costs to the PSEPCRA to begin recovering the costs from ratepayers. The Applicants contend they should be permitted to recover the capital-related costs of PSEP projects before the projects became used and useful to avoid creating "large PSEP related under collections that could have a significant rate impact to customers."[210] Accordingly, the Applicants propose to include forecasted capital-related costs in the PSEP Surcharge by designing the Surcharge to recover a forecast of PSEP costs including capital-related costs plus the under or over collection in the PSEPCRA from the prior year.[211] The consequence would be to base the PSEP Surcharge on a highly uncertain forecast that could have a wide margin for error instead of actual expenses and capital-related revenue requirements. As discussed below regarding the Applicants' proposed calculation of the PSEP Surcharge, the Applicants would defy established precedent by turning ratepayers into being their banks for short-term financing.

2. The PSEPCRA should include separate subaccounts for O&M expense and capital-related costs.

Subaccounts should be created within the PSEPCRA so that costs associated with expensed O&M activities including pressure testing are kept separate from the revenue requirements associated with capitalized projects such as pipeline replacements and new

[210] SCGC-26, p. 4 (Applicants/Reyes).

automated or remote control valves. Relying upon SAP internal orders within the Applicants' accounting systems to track the difference between O&M expenses and capital-related revenue requirements items would leave the Commission staff and interveners without a separate accounting for the two types of costs. Given the magnitude of the costs that the Applicants propose to recover through the PSEPCRA and the importance of distinguishing between O&M expenses and capital-related revenue requirements for ratemaking purposes, parties should be permitted an opportunity to track costs associated with the two types of activities readily. Hence the Commission should direct the PSEPCRA to be set up with the two separate subaccounts.

In response, the Applicants' witness Reyes only asserts: "SoCalGas and SDG&E should not have to distinguish between PSEP capital expenditures and O&M expenses"[212] without providing any rationale for why O&M expenses should be comingled with capital-related revenue requirements.

Maintaining the two separate subaccounts should not be burdensome on the Applicants. In his rebuttal testimony, witness Reyes refers to several accounts including the SoCalGas and SDG&E Advanced Metering Infrastructure ("AMI") balancing accounts. The Preliminary Statements of SoCalGas and SDG&E contain separate provisions for debiting O&M expenses and debiting capital-related costs:

> a. A debit entry equal to the AMI operating and maintenance costs incurred by the Utility, including the costs of development, accounting, evaluation and administration.
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> b. An entry equal to the AMI capital related costs incurred by the Utility for depreciation, property taxes, income taxes and return on investment.[213]

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[211] Ex. SCG-10, p. 126 (Applicants/Reyes).

[212] SCG-26, p. 5 (Applicants/Reyes).

[213] SoCalGas' AMI Project approved pursuant to Commission D.10-04-027 and incorporated in SoCalGas Preliminary Statement, Part V., Regulatory Accounts – Balancing. SDG&E's AMI project approved pursuant to

Presumably, the Preliminary Statement for the PSEPCRA would, likewise, contain separate requirements for debiting P&M expenses and debiting capital-related costs. That should facilitate maintaining separate subaccounts for O&M expenses and capital-related costs.

3. PSEPCRA balances should be amortized in the customary fashion by adjusting the prior year's revenue requirement.

Balances accumulated in the PSEPCRA should be recovered in accordance with the customary and Commission-approved methodology by adjusting the prior year's revenue requirement. As a balancing account, the PSEPCRA would be an account in which, according to the SoCalGas Preliminary Statement, "authorized expenses are compared with revenues from rates designed to recover those expenses."[214] The SoCalGas Preliminary Statement requires that under or over collection plus interest shall be recorded in the Utility's financial statement as a regulatory asset or regulatory liability which is either owed from or owed to the ratepayers: "The resulting under or over collection, plus interest calculated in the manner described in Preliminary Statement, Part I, is recorded on the Utility's financial statements as an asset or liability, which is owed from or due to the ratepayers."[215] The balances accumulated in balancing accounts are to be amortized rates."[216]

To be consistent with the Applicants' Preliminary Statement, after the PSEPCRA becomes effective, PSEP O&M expenses and capital-related costs should be debited to the Applicants' PSEPCRAs. At the end of the first year of operation of the PSEPCRAs, the Applicants will have accumulated regulatory assets to be amortized through rates in the following year. Those regulatory assets that the Applicants accumulate during the first year of

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Commission D.07-04-043, modified in D.11-03-042 and incorporated in SDG&E's Electric and Gas Preliminary Statements, Section II. – Balancing Accounts.

[214] SoCalGas Preliminary Statement—Part V—Balancing Account, Prescription and Listing of Balancing Accounts.

[215] *Ibid*.

operation of the PSEPCRAs should be the revenue requirements that are the basis for calculating the Applicants' PSEP Surcharges for the next year (unless, as discussed below, the Applicants are allowed to calculate PSEP Surcharges to recover PSRMA balances during the first year).

Each year, the Applicants file advice letters to revise their revenue requirements and resulting rates, effective on January 1 of the following year. The advice letters are called "Annual Regulatory Account Balance Updates."[217] Upon approval of the Annual Regulatory Account Balance Updates, the Applicants' revenue requirements and resulting rates are adjusted on January 1 of the following year to permit the Applicants to recover any under collections (regulatory assets) which are owed to the Applicants by ratepayers or over collections (regulatory liabilities) which are owed by the Applicants to ratepayers.

The SoCalGas System Reliability Memorandum Account ("SRMA") that became effective 2011 is a balancing account, its name notwithstanding, which provides an example of how the PSEPCRA should operate. During 2011, costs were debited to the SRMA and various revenues were debited to the account in accordance with the Preliminary Statement description of the SRMA resulting in an under collection of $2.2 million.[218] SoCalGas proposed in its 2011 Annual Regulatory Account Balance Update to revise its revenue requirement for 2012 to amortize the $2.2 million under collection in 2012, and the $2.2 million became part of the SoCalGas revenue requirement for 2012. [219]

If the SRMA over or under collection were to be amortized through a stand-alone surcharge like Phase 1A PSEP costs, the $2.2 million SRMA balance would constitute the 2012

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[216] *Ibid*.

[217] *See* e.g., SoCalGas Advice No. 4287 (October 17, 2011).

[218] Preliminary Statement-Part VI-Memorandum Accounts System Reliability Memorandum Account.

[219] SoCalGas Advice Letter No. 4287, Annual Regulatory Account Balance Update for Rates Effective January 1, 2012, Attachment C (Oct. 17, 2011).

revenue requirement that would provide the basis for the hypothetical 2012 SRMA surcharge. SoCalGas accumulated an under collection of $3.8 million in its SRMA in 2012[220]. The $3.8 million would be recovered in 2013 by adjusting the revenue requirement underlying the hypothetical 2012 SRMA surcharge, $2.2 million, upward by $1.6 million, resulting in a new total SRMA surcharge revenue requirement of $3.8 million for 2013. The hypothetical SRMA Surcharge would be calculated to recover a revenue requirement of $3.8 million in 2013.

Given that the PSEPCRA is a balancing account that is intended to be cleared each year by adjusting the PSEP Surcharge, the PSEP Surcharge should operate like the hypothetical SRMA surcharge to clear the PSEPCRA with the revenue requirement underlying the surcharge for a year being adjusted after the end of the year to amortize any over or under collection accumulated during the year.

4. The Applicants propose to calculate the PSEP Surcharge improperly.

The Applicants propose to debit "actual O&M and capital-related revenue requirements" in the PSEPCRA and to credit revenues "collected through the PSEP Surcharge."[221] Consequently, the Applicants will accumulate year-end under collections (regulatory assets) or over collections (regulatory liabilities) that, under their tariff, shall be recovered or returned to ratepayers the following year.

However, instead of calculating the PSEP Surcharge for the following year to adjust the PSEP Surcharge revenue requirement from the previous year upward to recover any net under collection (regulatory asset) or downward to return to ratepayers any net over collection (regulatory liability), the Applicants propose to have the net year-end under collection or over

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[220] SoCalGas Advice Letter 4411, Annual Regulatory Update for Rates Effective January 1, 2013, Attachment C (Oct. 15, 2012).

[221] Ex. SCG-10, p. 126.

collection added to or subtracted from their forecast of PSEP costs that they think they will incur during the coming year and to recover the resulting total from ratepayers.[222]

The Applicants should be required to add the PSEPCRA under collection (regulatory asset) to or subtract the PSEPCRA over collection (regulatory liability) from the revenue requirement that was the basis for the PSEP Surcharge for the year in which the under collection or over collection was accumulated. As discussed above, the Applicants' forecasts are unsuitable for establishing rates. Additionally, the Applicants' proposal turns ratepayers into being a bank to provide the Applicants with an interest free short-term loan, and their proposal is unprecedented.

a. The Applicants' proposal to calculate the PSEP Surcharge to recover a forecasted PSEP revenue requirement would cause ratepayers to provide interest free loans to the Applicants.

The Applicants expect that there will be a significant year-to-year increase in the revenue requirement associated with implementing the PSEP. According to Applicants' witness Reyes's revenue requirement summary for the Applicants, The Applicants' forecasted revenue requirements for SoCalGas are $6 million in 2011, $58 in 2012, $100 million in 2013, $182 million in 2014, and $247 million in 2015.[223] Thus, the increase in the forecasted SoCalGas annual revenue requirement from 2012 to 2013 would be 72 percent, the increase from 2013 to 2014 would be 82 percent, and the increase from 2014 to 2015 would be 36 percent.

In calculating the PSEP Surcharge, the Applicants propose to combine "the current-year forecasted year-end balances in the Pipeline Safety Enhancement Plan Cost Recovery Accounts combined with the revenue requirements [i.e., forecasted amounts] for the coming year" as a

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[222] *Ibid* SCG-10, p. 127 (Applicants/Reyes).

[223] Ex. SCG-10, p. 24 (Applicants/Reyes).

basis for the PSEP Surcharge.[224] As a result, ratepayers would be required to provide capital on a current basis before PSEP projects are used and useful to cover what the Applicants believe would be large year-to-year increases in PSEP expenditures.

In approving fuel cost adjustment clauses, one of the first balancing accounts that utilities were allowed to use in California, the Commission specifically found that balancing accounts should not function to provide a utility "the benefit of receiving large amounts of additional funds for its use at the expense of ratepayers…."[225] The Commission said:

> We can see no reason why the utility should have the benefit of receiving large amounts of additional funds for its use at the expense of the ratepayers simply because we are using a fictitious basis for determining its rates, particularly where the intention should be to match actual major increased expenses on a dollar-for-dollar basis.[226]

The Commission should not permit the Applicants to use the PSEPCRA to receive "large amounts of additional funds" that exceed the revenues ratepayers should contribute to cover actually incurred and reasonable costs.

b. **The Applicants fail to provide any precedent for using a forecasted revenue requirement to calculate the PSEP Surcharge.**

The Applicants fail to provide any precedent for their novel approach to calculating the PSEP Surcharge. Applicants' witness Reyes cites four balancing or memorandum accounts in his testimony: the SoCalGas Advanced Metering Infrastructure Balancing Account ("AIMBA"), the SDG&E AIMBA, the SDG&E Cuyamaca Peak Energy Plant Memorandum Account ("CPEPMA"), and SDG&E Solar Energy Project Balancing Account ("SEPBA").[227] However,

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[224] Ex. SCG-10, p. 127 (Applicants/Reyes).

[225] D.85731, 1976 Cal. PC Lexus 1.0; 79 CPUC 758 (April 27, 1976).

[226] *Ibid*.

[227] Ex. SCG-26, p. 4 (Applicants/Reyes).

none of these accounts are cleared by adding the net over collection or under collection that is accumulated in the account during the year to a forecasted revenue requirement for the succeeding years. For example, the SoCalGas and SDG&E AMIBAs provide that the "authorized revenue requirement" shall be a credit entry, not the amount to which a net over collection or under collection is added for recovery through rates during the succeeding year. The SoCalGas and SDG&E AIMBAs are described in the Utilities' Preliminary Statements as being maintained by making entries as follows:

> a. A debit entry equal to the AMI operating and maintenance costs incurred by the Utility, including the costs of development, accounting, evaluation and administration.
>
> b. An entry equal to the AMI capital related costs incurred by the Utility for depreciation, property taxes, income taxes and return on investment.
>
> c. A credit entry equal to the monthly AMI authorized revenue requirement recovered through rates.
>
> d. A credit entry equal to one-twelfth of the annual program benefits (included in the authorized revenue requirement in 4.c)[228]

None of the examples cited by witness Reyes provide a precedent for how the Applicants propose to calculate the PSEP Surcharge.

The Commission should not set a new precedent in this proceeding. If the Commission were to establish a precedent by permitting the PSEP Surcharge to be calculated by adding the PSEPCRA over collection or under collection to an amount forecasted for the year after the year in which the over collection or under collection were accumulated, it would be likely to lead to a gold rush with utilities seeking to revise balancing accounts so that they could clear under collections or over collections by adding the under collections to or subtracting the over collections from a forecasted amount rather than by adjusting the revenue requirement from the previous year.

The Applicants' proposal for calculating the PSEP Surcharge on the basis of forecasted amount should be rejected. The PSEPCRA under collections and over collections should be recovered from and returned to ratepayers by increasing or decreasing the revenue requirement that was the basis for calculating the PSEP Surcharge during the year in which the over collection or under collection was accumulated as is done conventionally.

5. The PSEPCRA and the PSEP Surcharge should be terminated after the Applicants' Test Year 2012 GRC.

Under the MAAC procedure, projects were placed into base rates as soon as possible.[229] Consistent with the MAAC precedent, witness Yap proposed that "projects should be transferred out of the PSEPCRA as soon as possible."[230] As projects are reflected in base rates, the associated costs should be removed from the PSEPCRA Surcharge.[231]

In their rebuttal testimony, the Applicants agreed "that the revenue requirements associated with PSEP projects should eventually be incorporated in the authorized revenue requirement in connection with a GRC."[232] The Applicants' next GRC will be for Test Year 2016. Accordingly, costs and revenues should be debited and credited to the PSEPCRA through 2015. No new costs should be booked into the PSEPCRA during 2016.[233] The PSEPCRA should remain open, however, during 2016 to allow for recovery of over or under collections of

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[228] SoCalGas Preliminary Statement-Part V-Balancing Accounts, Advanced Metering Infrastructure Balancing Account; SDG&E Preliminary Statement, Balancing Accounts, Advanced Metering Infrastructure Balancing Account.

[229] SCGC-1, p. 29 (SCGC/Yap).

[230] *Ibid*.

[231] *Ibid*.

[232] Ex. SCG-26, p. 8 (Applicants/Reyes).

[233] SCGC-1, p. 30 (SCGC/Yap).

PSEP balances.[234] The PSEPCRA and the PSEP Surcharge should be terminated at the beginning of 2017.[235]

B. Rate Recovery of Authorized Phase IA Costs.

The Applicants seek "Commission authorization" to recover their Phase 1 PSEP costs as forecasted for each of the years 2012 through 2015.[236] As discussed above, the Applicants' request should be denied. The Applicants' forecasts are unsuitable for ratemaking.

1. The Applicants' estimates are too inaccurate to be used for ratemaking.

The Applicants admit that their forecasts are classified at best, "between 4 and 5."[237] For Class 5 estimates the level of project definition is only zero to 2 percent.[238] The AACE notes that Class 5 estimates are characterized as "ratio, ballpark, blue sky, seat-of-pants, ROM, idea study, prospect estimate, concession license estimate, guesstimate, rule-of-thumb."[239] For Class 4 estimates, the level of project definition is between 1 percent and 15 percent, not much better than the Class 5 level of project definition. SCGC witness Yap observes:

> At this level there is only a general sense of what the project requires. Clearly, this is what we see from the Applicants' workpapers and responses to discovery. The Applicants can only provide very general responses regarding each project because there has been very limited engineering work done on each project.[240]

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[234] *Ibid*.

[235] *Ibid*.

[236] Ex. SCG-01, p. 6 (Applicants/Morrow).

[237] Ex. SCG-21, p. 2 (Applicants/Buczkowski); Tr. 881 (Applicants/Buczkowski).

[238] SCGC-1, p. 26 (SCGC/Yap).

[239] SCGC-1, p. 26; Attachment M; SoCalGas/SDG&E Response to SCGC-17.5.2—AACE International Recommended Practice No. 18R-97, at 2.

[240] *Ibid*, p. 25.

Witness Yap concluded: "While it is true that the Applicants had a great many pipeline projects to analyze in a short period of time in preparing their PSEP, the Commission should have little or no confidence in the cost estimates that are prepared at such a low level of accuracy."[241]

2. The proposed expedited advice letters are not a cure for the inaccurate forecasts.

The Applicants propose "propose to file expedited advice letters requesting approval for any adjustments to the overall level of Pipeline Safety Enhancement Plan funding requirements previously approved."[242] However, as discussed below, there is no assurance about the quality of information that would be provided in the expedited advice letter or even assurance that there would be any information. Furthermore, stakeholders as well as the Commission would have scant opportunity to investigate the "adjustments" proposed in the expedited advice letters.

3. The proposed use of the forecasts is improper.

As discussed above, the way in which the Applicants would use their annual forecasts, if authorized, is improper. They would improperly use the "authorized forecast" for a year in combination with the balance accumulated in the PSEPCRA for the previous year to determine the PSEP Surcharge, effectively turning ratepayers into being contributors of short term capital to the Applicants, contrary to Commission policy and precedent.

4. The Commission should reject the Applicants' proposal for recovery of "an authorized" forecast through the PSEP Surcharge.

Accordingly, the Applicants' request for "approval" of their forecasts and their request for "authorization" to recover the forecasted annual amounts, even as "adjusted" through their proposed expedited advice letters, should be categorically rejected. Instead, the Applicants should be directed to undertake compliance with Decision D.11-06-017, with expenses being

[241] *Ibid*, p. 26.

[242] Ex. SCG-10, p. 127 (Applicants/Reyes).

recorded in the PSRMA for now and in the PSEPCRA after approval of the PSEPCRA and with all pipeline replacement projects being scrutinized through EAD process described above. Review and approval of well defined and well engineered projects through the EAD process would be much more likely to protect ratepayer interests than authorizing the speculative forecasts offered by the Applicants.

C. Rate Recovery of Costs Recorded in the PSEP Memorandum Account.

The Applicants propose to file compliance advice letters to implement their PSEPCRAs after the Commission issues a decision approving the PSEPCRAs.[243] The Applicants plan to request in their compliance advice letters authorization to recover the costs recorded in their PSRMAs through their PSEP Surcharges. Furthermore, the Applicants propose to start charging their PSEP Surcharges on the first day of the first month following Commission approval of their compliance advice letters, with revenues derived from charging their PSEP Surcharges being credited to their PSEPCRAs.[244]

Before commencing recovery of costs debited to the Applicants' PSRMAs, there must be an opportunity for the Commission to consider whether the recorded costs are reasonable so that they can legitimately be recovered from ratepayers. The Commission stated in D.12-04-021: "The Commission will consider whether such properly recorded costs are reasonable and incremental as well as which costs, if any, may be recovered from ratepayers in revenue requirement at a later time in the Triennial Cost Allocation Proceeding."[245]

To the extent to which the Commission has an opportunity to consider amounts recorded in the Applicants' PSRMAs and finds that the recorded costs are reasonable and incremental so

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[243] Ex. SCG-10, p. 126.

[244] Tr. 1551 (Applicants/Reyes).

[245] D.12-04-021, p. 7 (April 19, 2012).

as to be recovered from ratepayers, it would be appropriate to transfer the costs as a debit to the PSEPCRA and to permit the Applicants to commence recovery of the costs through the "year one" PSEP Surcharge, with resulting revenues being credited to the PSEPCRA. The amount accumulated in the PSRMA would then effectively become the "year one" revenue requirement that provides a basis for calculating the "year one" PSEP Surcharge. This would address the Applicants' apparent desire to have revenues credited to the PSEPCRA during "year one" in addition to having costs debited during that year.

D. Expedited Advice Letter For Proposed Adjustments to PSEP Funding.

The Applicants request authority to submit "expedited advice letters" to adjust previously approved annual forecasts of PSEP expenditures.[246] As discussed above, they propose to base their PSEP Surcharges for a given year on forecasted PSEP expenses and capital-related revenue requirements for the year plus an amount to amortize any PSEPCRA over collection or under collection from the previous year. The Applicants say that their expedited advice letters "would include an explanation for changes from the original revenue requirements, as previously proposed and approved" and would, also, request "any additional revenue requirement associated with the Enterprise Asset Management System or the expansion of the Pipeline Safety Enhancement Plan for pipeline safety enhancement activities" which is not covered by the application being considered in this proceeding.[247]

The Applicants' request to submit expedited advice letters should be rejected.

1. There should be no need for the Applicants' proposed expedited advice letters.

There should not be any need for expedited advice letters to adjust "previously approved" annual forecasts because the Applicants' forecasted annual PSEP revenue requirements should

[246] Ex. SCG-10, p. 127 (Applicants/Reyes).

not be included in the calculation of the PSEP Surcharges and should not be approved in this proceeding. In short, there should be no need for expedited advice letters to adjust approved forecasted annual PSEP revenue requirements because there should be no approved forecasted PSEP revenue requirements.

2. The expedited advice letter process would be unfair to stakeholders.

Even if there were approved forecasts of annual PSEP revenue requirements, the Applicants' expedited advice letter process would effectively deny stakeholders any meaningful opportunity to scrutinize the proposed adjustments. As proposed by the Applicants, under the expedited advice letter process, stakeholders would have only 10 days rather than the usual 20 days to protest the advice letters, and a Commission decision would be required in 21 days.[248]

The normal 20 day period for protests is already too short. With a 20 day protest period, there is little opportunity for stakeholders to conduct meaningful discovery about advice letter proposals and too short a time to effectively digest complex proposals. Shortening the protest period to 10 days would further prejudice stakeholders, damaging their ability to assist the Commission by offering informed analyses of the Applicants' proposals.

The Applicants' proposal for an expedited advice letter process for proposed adjustments to forecasted annual PSEP revenue requirements should be rejected along with the Applicants' proposal to base the PSEP Surcharge on forecasted annual PSEP revenue requirements.

E. Annual PSEP Update Report.

Beginning in 2013, the Applicants propose to provide an annual status report to the Commission on or before March 31 of each year that would include the following:

1. Information on any work completed during the previous year (scope and cost);

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[247] *Ibid*.

[248] Tr. 1554 (Applicants/Reyes).

2. Work planned for the upcoming year (scope and cost);

3. Discussion of progress made to date in order to keep the Commission informed and provide transparency to the public regarding our progress; and

4. Confirmation of our Commission-approved annual Pipeline Safety Enhancement Plan budget.[249]

Unfortunately, as proposed, the annual report would have limited usefulness. First, the report would only be informational. It would not constitute a request for Commission action of any sort.[250]

Second, while the report might be available to parties to the instant proceeding, it would not be submitted to the Commission through the advice letter process.[251] In fact, the Applicants oppose filing the annual report through an advice letter.[252] As a result, the list of recipients would not be as broad as the list of recipients of the Applicants' advice letters, and there would be no mechanism for the stakeholders who do receive the report to provide comments on the report either to the Applicants or to the Commission.[253]

There will be a tremendous information asymmetry about implementation of the PSEP: the Applicants will have all the information and stakeholders will have none. The annual report will help to close information gap, but the report would be more useful if it were circulated to more parties and if there were a formal opportunity to provide comments through the advice letter process.

Accordingly, SCGC supports the Applicants' proposal to submit an annual status report starting in 2013, but SCGC recommends that the report be submitted to the Commission through

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[249] Ex. SCG-10, p. 127 (Applicants/Reyes).

[250] Tr. 1182 (Applicants/Phillips).

[251] Tr. 1565-1566 (Applicants/Reyes).

[252] Tr. 1567 (Applicants/Reyes).

[253] Tr. 1566 (Applicants/Reyes).

an advice letter so that it would be a mechanism for stakeholders to provide input to the Applicants and the Commission about the contents of the report.

IX. ADDITIONAL INTERVENOR PROPOSALS.

The Commission should reject the SCIP proposal to recover 50 percent of the cost of a Backbone Transmission Service ("BTS") credit from shareholders and 50 percent from noncore end-use customers.

A. Proposed Notice Requirement.

B. Local Transmission Interruption Credit Proposal.

C. BTS Reservation Charge Credit Proposal.

SCIP recommends that the Commission direct the Applicants to provide a credit toward BTS reservation charges for any period during which customers have their BTS service disrupted by PSEP work.[254] SCIP further recommends that the "BTS reservation credit should be funded 50% by Sempra shareholders," with the ratepayers' share of the costs for the credits being recovered from noncore customers through the Noncore Fixed Cost Balancing Account ("NFCA").[255]

SCGC does not take a position on whether SCIP's proposal for a BTS reservation charge credit should be adopted, but the Commission should reject SCIP's proposal to make shareholders responsible for 50 percent of the costs of the credits, and the Commission should reject SCIP's proposal to recover 50 percent of the credits from noncore customers through the NFCA. If there were to be BTS reservation charge credits, the full cost should be borne by BTS customers by recording the cost of the credits in the Backbone Transmission Balancing Account ("BTBA").

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[254] Ex. SCIP-1, p. 23 (SCIP/Beach).

[255] *Ibid*, pp. 23-24, (Footnote 29) (SCIP/Beach).

1. The Applicants' shareholders should not be required to bear 50 percent of the cost of any BTS credits.

Requiring the Applicants' shareholders to bear 50 percent of the cost of the credits would give the Applicants an incentive to pursue pipeline replacements if there is a potential for pressure testing to interrupt BTS service. Providing shareholders with an incentive to replace rather than pressure test pipeline segments would work against the interests of ratepayers. As discussed above, pressure testing and replacement are equally effective in ensuring pipeline safety, but replacing pipelines is much more expensive than pressure testing, both in terms of direct costs and in terms of revenue requirement impact over the life of the facilities. Thus, it is not in the ratepayers' interest to create an incentive for the Applicants to replace rather than pressure testing pipeline segments.

2. Noncore end-use customers should not be required to bear 50 percent of the cost of any BTS credits.

The cost of the BTS credits, if any, should not be recovered from noncore end-use customers through the NFCA. The SoCalGas Preliminary Statement description of the NFCA clearly prohibits recovery of the costs of SCIP's proposed BTS credit by precluding recovery of any portion of the backbone revenue requirement through the NFCA. The description of the NFCA states that the "purpose of this account is to balance the difference between the authorized margin (excluding the transmission revenue requirement and Backbone Transmission Service BTS revenue requirement) and other non-gas costs…."[256] Thus, recovery of any portion of the cost of BTS credits from the general body of noncore ratepayers by recording the cost in the NFCA is prohibited.

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[256] SoCalGas Preliminary Statement, Part V, NFCA, Sheet 1.

3. The cost of BTS credits, if any, should be recovered from BTS customers.

If the proposed BTS reservation charge credits were to be approved, the cost of the credits should be recovered in their entirety from BTS customers through the BTBA. The description of the BTBA explains that its purpose is "to record the difference between the authorized Backbone Transportation Service BTS revenue requirement and the actual BTS revenues from firm and interruptible access to SoCalGas' transmission system."[257] Accordingly, should the Commission decide to adopt SCIP's proposed BTS reservation charge credits for BTS service interruptions caused by PSEP activities, any costs of offering the credit should be recovered through the BTBA.

X. PHASE 1B

A. Line 1600.

Line 1600 is a 16-inch transmission line about 50 miles in length that delivers gas into San Diego from SDG&E's interconnection with SoCalGas at Rainbow Station.[258] Some of those miles are Category 4 Criteria Miles.[259] As an interim safety measure, the Applicants have already reduced the pressure on Line 1600 to 81.2 percent of its operating pressure.[260]

The Applicants have further plans for Line 1600. They propose to replace Line 1600 with an entirely new 36-inch pipeline that would have a direct cost of about $325 million.[261]

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[257] *Ibid*, BTBA, Sheet 1.

[258] Ex. SCGC-1, p. 18 (SCGC/Yap).

[259] Report of SoCalGas and SDG&E on actions taken in response to the NTSB safety recommendations, R.11-02-019, p. 10 (April 15, 2011).

[260] SCGC-1, Attachment M, SoCalGas/SDG&E Response to SCGC-17.6 are still in the Applicants' Category 4, the Applicants have already created a safety margin on Line 1600.

[261] Technical Report of CPSD regarding the SoCalGas and SDG&E Pipeline Safety Enhancement Plan, R.11-02-019, p. 12 (January 17, 2012).

After replacing Line 1600, the Applicants would pressure test Line 1600 to keep the pipeline in service.[262]

The replacement of Line 1600 and the subsequent pressure testing is the only Category 4 project that is in the Applicants' Phase 1B.[263] The Line 1600 replacement and pressure testing project is in Phase 1B because the scope of the project, particularly the construction of the new 36 inch pipeline, is so great that it cannot be completed in Phase 1A. The only Line 1600 costs that the Applicants include in Phase 1A, according to the Applicants' witness Rivera, is approximately 4 percent of the total cost with the remaining 96 percent being incurred in Phase 1B between 2016 and 2018.[264]

No costs should be incurred for Line 1600 in Phase 1A. The Applicants are currently making Line 1600 piggable as part of their Transmission Integrity Management Plan ("TIMP") activities.[265] A piggable Line 1600 would be able to accept TFI technology to validate the long seam stability of Line 1600.

As discussed above, the Applicants are proposing to use the TFI technology prior to pressure testing pipelines in Phase 1A and to present the results of their experience to the Commission in the Applicants' Test Year 2016 GRC. If the TFI technology is validated in Phase 1A, the Applicants plan to propose in their Test Year 2016 GRC that the Commission approve TFI as an alternative to pressure testing or replacing pipelines. If such approval were obtained, Line 1600 could be inspected while the line remains in service at a comparably small expense.[266]

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[262] *Ibid*.

[263] *Ibid*; SCG-04, p. 60 (Applicants/Schneider).

[264] Ex. SCGC-4, p. WP-IX-1-34.

[265] Ex. SCGC-1, Att. S, SoCalGas/SDG&E Response to DRA-DAO-24-02.

[266] SCGC-1, p. 19 (SCGC/Yap).

The need for replacing Line 1600 with a costly 36-inch pipeline would, at least from a safety perspective, be avoided, and the cost of pressure testing Line 1600 would be avoided as well.

Thus, 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.

It is particularly inappropriate to incur any costs in Phase 1A insofar as the Applicants' proposal to construct a new 36-inch diameter pipeline appears to be a project that is aimed at increasing capacity than addressing the type of safety improvements ordered by D.11-06-017.[267] A 36-inch pipeline has five times the delivery volume of a 16-inch pipeline because the cross-sectional area of a pipeline increases as the square of the pipeline radius.[268] In fact, a 36-inch pipeline has more cross-sectional area than 16-inch pipeline plus a 30-inch pipeline combined.[269]

XI. PHASE 2.

The Applicants are not seeking Commission consideration of Phase 2 activities in this proceeding. The Applicants state: "Because we have not yet completed our review of records for Phase 2 pipelines, we are unable to provide Phase 2 cost estimates to any level of certainty."[270] The Applicants state that the total direct cost could be in the range of $1.5 to $3.0 billion or more for SoCalGas and about $100 million for SDG&E for Phase 2, but they caution that their estimates are "speculative."[271]

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[267] DPSD Report, p. 13.

[268] SCGC-1, p. 20 (SCGC/Yap).

[269] *Ibid*, p. 21.

[270] Ex. SCG-09, p. 119 (Applicants/Rivera).

[271] *Ibid*.

Commission authorization to utilize TFI in lieu of pressure testing and replacement in the Applicants' Test Year 2016 GRC could greatly reduce Phase 2 costs. The Applicants estimate that approximately 56 percent of the Phase 2 miles "are already retrofitted to accommodate in line inspections."[272] They say that if the use of TFI were approved by the Commission, "this would reduce the amount of mileage requiring pressure testing or replacing potentially savings hundreds of millions of dollars."[273]

Adopting the Applicants' other three proposed alternatives to pressure testing or replacing pipeline segments, as discussed above, could "further reduce the scope and cost of Phase 2."[274] Given the lack of any meaningful Applicant proposal for Phase 2, and given the potential for TFI technology, if approved in the GRC, and the other alternatives to pressure testing or replacement that the Applicants propose in this proceeding to significantly affect Phase 2 activities, SCGC supports deferral of Phase 2 issues.

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272 Ex. SCG-09, p. 119 (Applicants/Rivera).

273 *Ibid*.

274 *Ibid*.

XII. CONCLUSION.

For the reasons set forth herein above, SCGC respectfully requests that the Commission adopt the recommendations by SCGC as set forth in the Summary of Recommendations above.

Respectfully submitted,

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Dated: October 19, 2012

EXHIBIT G

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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

**SOUTHERN CALIFORNIA GENERATION COALITION
REPLY BRIEF**

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SUMMARY OF RECOMMENDATIONS

On the basis of the evidentiary record in this proceeding, the Southern California Generation Coalition ("SCGC") respectfully requests that the Commission issue a decision that adopts the recommendations presented below. The recommendations are presented in the sequence in which they are discussed in SCGC's Opening and Reply Briefs in accordance with the Common Briefing Outline for this proceeding:

- The Applicants' shareholders should bear the cost of Phase 1A testing or replacing all pipeline segments installed after July 1, 1961, for which the Applicants do not have sufficient documentation of post-construction pressure tests to at least 1.25 times MAOP.

- There should be effective Commission review on a case-by-case basis of the Applicants' decisions in Phase 1A to replace pipeline segments greater than 1,000 feet in length instead of pressure testing the segments.

    - The case-by-case review of replacement decisions should be through an Expedited Application Docket ("EAD") procedure.

    - Insofar as the Applicants propose 74 replacement projects that are over 1,000 feet in length, but 44 projects costing more than $5 million each representing 85 percent of the Applicants' projected total Phase 1A direct cost of replacements, it would be a reasonable compromise to limit EAD review to replacement projects for which the direct cost is projected to exceed $5 million.

    - The cost estimates presented in EAD proceedings should be at least Class 3 estimates.

    - The Applicants' estimate of the cost of a replacement project, if approved in an EAD proceeding, should be the cost cap for the project, with costs that exceed the cap being recovered by the Applicants only if approved by the Commission after a subsequent reasonableness review.

- The Applicants' proposal for an Engineering Advisory Board as an alternative to Commission review of replacement decisions through the EAD process should be rejected.

- The Commission should permit the Applicants to continue to use the "grandfathering clause" in 49 CFR 192.619(c) as the basis for establishing a pipeline's MAOP if the MAOP is validated by meeting one of the four alternative conditions proposed by the Applicants' witness Schneider to assure the safety of the pipeline:

  - First alternative condition: For pipelines that were pressure tested before November 12, 1970, a post-construction strength test to at least 1.25 times MAOP with records showing the test medium and test pressure.

  - Second alternative condition: For pipelines placed in service prior to November 12, 1970, the MAOP has been lowered to less than or equal to 72 percent of the highest actual operating pressure documented during the five years preceding the pressure reduction.

  - Third alternative condition: Complete non-destructive examination using an inspection method capable of seam anomaly detection with remediation of seam defects that have predicted failure pressures of less than or equal to 1.39 times MAOP.

  - Fourth alternative condition: After Transverse Field Inspection ("TFI") has been approved by the Commission as equivalent to pressure testing, TFI followed by validation of identified potential anomaly areas using non-destructive evaluation methods capable of seam anomaly detection with remediation of seam defects that have predicted failure pressures less than or equal to 1.39 times MAOP.

- The Applicants should be permitted to "accelerate" pressure testing or replacing Phase 2 miles to Phase 1 only if the Applicants obtain Commission approval of the acceleration on a project-specific basis.

- The Commission should reject the use of the Applicants' forecasts of annual PSEP revenue requirements as a basis for calculating the Applicants' PSEP Surcharge.

- The Commission should allow the Applicants to recover only actually incurred costs through the Pipeline Safety Enhancement Plan Cost Recovery Account ("PSEPCRA") and the PSEP Surcharge.

  - The Applicants should debit their PSEPCRAs with actually incurred PSEP O&M expenses and actually incurred PSEP capital-related revenue requirement on a monthly basis.

  - The monthly capital-related revenue requirement for a project should be debited to the PSEPCRA only after the project becomes used and useful.

- The Applicants should credit their PSEPCRAs with actual revenues recovered through their PSEP Surcharges on a monthly basis.
- The PSEPCRA should include sub-accounts for debiting O&M expenses and debiting capital-related costs.
- PSEPCRA year-end balances should be amortized through the Applicants' Annual Regulatory Account Balance Updates by adjusting the revenue requirements that underlie the Applicants' PSEPCRA Surcharges for the year in which the balances were accumulated so as to amortize the year-end balances during the following year.

- The Commission should reject the Applicants' proposal to calculate the PSEP Surcharge by adding a year-end PSEPCRA under-collection to or subtracting a year-end PSEPCRA over-collection from a forecast of PSEP revenue requirement for the following year.

- The revenue requirements associated with PSEP projects should be incorporated into the Applicants' authorized revenue requirement in the Applicants' Test Year 2016 General Rate Case ("GRC").
  - No new costs should be booked into the Applicants' PSEPCRAs during 2016.
  - The Applicants' PSEPCRAs and the PSEP Surcharges should be terminated at the beginning of 2017.

- The Applicants' request for permission to file expedited advice letters to adjust their forecasts of annual PSEP expenses should be rejected.

- If the Commission finds that the costs debited to the Applicants' Pipeline Safety and Reliability Memorandum Accounts ("PSRMAs") are reasonable so that the costs may be recovered from ratepayers, the Commission should permit the Applicants to transfer their PSRMA balances as a debit to their PSEPCRAs and to recover the balances through their "year one" PSEP Surcharges with collected revenues being credited to their PSEPCRAs.

- The Applicants should be required to submit their proposed annual PSEP Update Reports through an advice letter.

- If the Commission elects to approve the proposal for Backbone Transmission Service ("BTS") reservation charge credits, the cost of offering the credits should be recovered through the Backbone Transmission Balancing Account ("BTBA") from BTS customers. No "pre-engineering" costs should be incurred in Phase 1A for the proposed 36-inch replacement of Line 1600 that is deferred to Phase 1B.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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

**SOUTHERN CALIFORNIA GENERATION COALITION
REPLY BRIEF**

In accordance with Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the schedule established by Administrative Law Judge ("ALJ") Long,[1] the Southern California Generation Coalition ("SCGC") respectfully submits this reply brief in the captioned proceeding. The brief follows the Common Briefing Outline for this proceeding.

I. INTRODUCTION.

SCGC replies primarily to the Opening Brief filed by the Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (jointly, "Applicants") on October 19, 2012, on Pipeline Safety Enhancement Plan ("PSEP") proposals.[2] SCGC strongly opposes several of the Applicants' proposals on issues including shareholder cost responsibility, review of decisions to replace rather than pressure the pipeline segments, "acceleration" of Phase 2 miles to Phase 1, the recovery of forecasted PSEP annual revenue

[1] Transcript ("Tr.") 1633. By e-mail Ruling dated October 12, 2012, ALJ Long extended the date of submission for reply briefs in this proceeding from November 2, 2012, to November 9, 2012.

[2] In addition to the Applicants and SCGC, the following parties filed opening briefs in this proceeding: Division of Ratepayer Advocates ("DRA"), Southern California Edison Company ("SCE"), Southern California Indicated Producers ("SCIP"), and Utility Workers Union of America ("UWUA").

requirement through the PSEP Surcharge, the recovery of capital-related project costs before the project becomes used and useful, the use of expedited advice letters to adjust forecasted revenue requirements, and the recovery of "pre-engineering" costs for a 36-inch pipeline in San Diego County. However, conversely, SCGC supports a number of proposals that were sponsored by the Applicants' witnesses in this proceeding.

A. Proposals by the Applicants' Witnesses that Were Ignored in the Applicants Opening Brief.

Unfortunately, some of the witnesses' best proposals were inexplicably ignored by the Applicants in their Opening Brief. For example, one of the Applicants' lead witnesses, Douglas Schneider, proposed an alternative to pressure testing or replacing pre-1970 transmission pipelines to meet the "modern standards" in 49 Code of Federal Regulations ("CFR") Part 192. He proposed that the Commission should retain the "grandfathering" provision in 49 CFR 192.619(c) but should strengthen General Order 112-E to require that a pipeline operator must have a record of a post-construction strength test to at least 1.25 times the Maximum Allowed Operating Pressure ("MAOP") for any transmission pipeline constructed before November 12, 1970, with the record showing the test medium and test pressure.[3] Witness Schneider's proposed alternative was not even mentioned in the Applicants' Opening Brief.

1. Witness Schneider's alternative would have an important impact on the scope of work in Phase 2.

Adoption of witness Schneider's proposed alternative would have an important consequence for the Applicants' Pipeline Safety Enhancement Plan ("PSEP"). The Applicants contend in the introduction to their Opening Brief that "even if SoCalGas and SDG&E had a record of every pressure test ever performed," they would still be required by Decision ("D") 11-

[3] Exhibit ("Ex.") SCG-04 (Applicants/Schneider).

06-017[4] to pressure test or replace transmission pipeline segments that do not meet the "modern standards" in 49 CFR Part 192.[5] However, if witness Schneider's alternative were adopted, the Applicants would not be required to pressure test or replace pre-1970 pipelines to meet the "modern standards" if the pipelines had a record of a pressure test to 1.25 times MAOP with the record showing the medium used for the test and the test pressure.[6]

Avoiding the need to pressure test or replace pre-1970 pipelines for which the Applicants have a sufficient record of a pressure test could have a profound impact on the Phase 2 scope of work and resulting costs. Although the record on Phase 2 is skimpy, it appears from the Applicants' Phase 2 direct cost and revenue requirement projections that while pipelines in Class 1 and 2 areas that lack records of pressure testing will be addressed in Phase 2, most of the Phase 2 work will be on pre-1970 pipelines for which the Applicants have pressure test records but which were not tested to "modern" post-1970 standards.[7]

2. Witness Schneider's alternative could also have an important impact on the scope of work in Phase 1A.

Witness Schneider's proposal could also have an important impact on the scope of work in Phase 1A. Avoiding the need to pressure test or replace pre-1970 pipelines for which the Applicants have a sufficient record of a pressure test could obviate any benefits that might result from "accelerating" Phase 2 work to Phase 1A. As proposed by the Applicants, about 45 percent[8] of the miles that would be pressure tested or replaced in Phase 1A are "accelerated" miles that would otherwise be pressure tested or replaced in Phase 2. The Applicants propose to "accelerate" Phase 2 miles to Phase 1A because doing work on the "accelerated" Phase 2 miles

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[4] D.11-06-017 (June 9, 2011).

[5] Applicants Opening Brief, p. 3.

[6] SCGC Opening Brief, pp. 42-43.

[7] Ex. SCG-10, pp. 124-125 (Applicants/Reyes).

in conjunction with pressure testing or replacing Phase 1A miles could result in some overall savings in direct costs (3.5 to 8.0 percent for replacements and 30 to 200 percent for pressure testing).[9] Adoption of witness Schneider's proposed alternative would mean that work on many if not all of the "accelerated" Phase 2 miles might be avoided altogether, negating the alleged benefits of acceleration.

Likewise, if the Applicants are permitted to validate Transverse Field Inspection ("TFI") as proposed by witness Schneider, and if the validated TFI were approved by the Commission as an alternative to pressure testing or replacing pipelines, work might be avoided on the Phase 2 miles that the Applicants want to "accelerate" to Phase 1.

Accordingly, in order to preserve the opportunity to realize the savings that could be realized if witness Schneider's first alternative were approved and if TFI were approved as an alternative to pressure testing, SCGC supports TURN's proposal to permit the Applicants to "accelerate" Phase 2 miles to Phase 1 only if the Applicants obtain Commission approval of the acceleration on a project-specific basis.[10]

B. Clarified and Expanded Recommendations.

Upon consideration of the points raised in the Applicants' Opening Brief, SCGC clarifies and expands some of its recommendations in this proceeding. For example, in its Opening Brief, SCGC recommended that the Commission should require the Applicants to submit applications on a case-by-case basis using Expedited Application Docket procedures to obtain permission to replace rather than pressure test pipeline segments greater than 1,000 feet in length. As discussed below, the Applicants propose 74 replacements of pipeline segments that are greater

[88] Ex. 34R (Applicants).

[9] Applicants Opening Brief, p. 112.

[10] TURN Opening Brief, p. 63.

than 1,000 feet in length. The Applicants suggest in their Opening Brief that while "hundreds" of EAD applications would not be acceptable, "dozens" might be acceptable.[11] In order to limit the number of applications to "dozens," SCGC believes it would be a reasonable compromise to limit EAD review to replacement projects for which the direct cost is projected to exceed $5 million. Only 44 of the Applicants' Phase 1A replacement projects exceed $5 million, but they represent 85 percent of the Applicants' projected total Phase 1A direct cost of replacements.[12]

SCGC's recommendations as clarified and expanded upon consideration of the Applicants' Opening Brief are as follows:

- The Applicants' shareholders should bear the cost of Phase 1A testing or replacing all pipeline segments installed after July 1, 1961, for which the Applicants do not have sufficient documentation of post-construction pressure tests to at least 1.25 times MAOP.
- There should be effective Commission review on a case-by-case basis of the Applicants' decisions in Phase 1A to replace pipeline segments greater than 1,000 feet in length instead of pressure testing the segments.
    - The case-by-case review of replacement decisions should be through an Expedited Application Docket ("EAD") procedure.
    - Insofar as the Applicants propose 74 replacement projects that are over 1,000 feet in length, but 44 projects costing more than $5 million each representing 85 percent of the Applicants' projected total Phase 1A direct cost of replacements, it would be a reasonable compromise to limit EAD review to replacement projects for which the direct cost is projected to exceed $5 million.
    - The cost estimates presented in EAD proceedings should be at least Class 3 estimates.
    - The Applicants' estimate of the cost of a replacement project, if approved in an EAD proceeding, should be the cost cap for the project, with costs that exceed the cap being recovered by the Applicants only if approved by the Commission after a subsequent reasonableness review.

[11] Applicants Opening Brief, p. 104.

[12] SCGC-4; Ex. SCG-32, pp. WP-IX-1-23 through WP-IX-1-37.

- The Applicants' proposal for an Engineering Advisory Board as an alternative to Commission review of replacement decisions through the EAD process should be rejected.

- The Commission should permit the Applicants to continue to use the "grandfathering clause" in 49 CFR 192.619(c) as the basis for establishing a pipeline's MAOP if the MAOP is validated by meeting one of the four alternative conditions proposed by the Applicants' witness Schneider to assure the safety of the pipeline:

    - <u>First alternative condition</u>: For pipelines that were pressure tested before November 12, 1970, a post-construction strength test to at least 1.25 times MAOP with records showing the test medium and test pressure.

    - <u>Second alternative condition</u>: For pipelines placed in service prior to November 12, 1970, the MAOP has been lowered to less than or equal to 72 percent of the highest actual operating pressure documented during the five years preceding the pressure reduction.

    - <u>Third alternative condition</u>: Complete non-destructive examination using an inspection method capable of seam anomaly detection with remediation of seam defects that have predicted failure pressures of less than or equal to 1.39 times MAOP.

    - <u>Fourth alternative condition</u>: After Transverse Field Inspection ("TFI") has been approved by the Commission as equivalent to pressure testing, TFI followed by validation of identified potential anomaly areas using non-destructive evaluation methods capable of seam anomaly detection with remediation of seam defects that have predicted failure pressures less than or equal to 1.39 times MAOP.

- The Applicants should be permitted to "accelerate" pressure testing or replacing Phase 2 miles to Phase 1 only if the Applicants obtain Commission approval of the acceleration on a project-specific basis.

- The Commission should reject the use of the Applicants' forecasts of annual PSEP revenue requirements as a basis for calculating the Applicants' PSEP Surcharge.

- The Commission should allow the Applicants to recover only actually incurred costs through the Pipeline Safety Enhancement Plan Cost Recovery Account ("PSEPCRA") and the PSEP Surcharge.

    - The Applicants should debit their PSEPCRAs with actually incurred PSEP O&M expenses and actually incurred PSEP capital-related revenue requirement on a monthly basis.

- The monthly capital-related revenue requirement for a project should be debited to the PSEPCRA only after the project becomes used and useful.

- The Applicants should credit their PSEPCRAs with actual revenues recovered through their PSEP Surcharges on a monthly basis.

- The PSEPCRA should include sub-accounts for debiting O&M expenses and debiting capital-related costs.

- PSEPCRA year-end balances should be amortized through the Applicants' Annual Regulatory Account Balance Updates by adjusting the revenue requirements that underlie the Applicants' PSEPCRA Surcharges for the year in which the balances were accumulated so as to amortize the year-end balances during the following year.

- The Commission should reject the Applicants' proposal to calculate the PSEP Surcharge by adding a year-end PSEPCRA under-collection to or subtracting a year-end PSEPCRA over-collection from a forecast of PSEP revenue requirement for the following year.

- The revenue requirements associated with PSEP projects should be incorporated into the Applicants' authorized revenue requirement in the Applicants' Test Year 2016 General Rate Case ("GRC").

  - No new costs should be booked into the Applicants' PSEPCRAs during 2016.

  - The Applicants' PSEPCRAs and the PSEP Surcharges should be terminated at the beginning of 2017.

- The Applicants' request for permission to file expedited advice letters to adjust their forecasts of annual PSEP expenses should be rejected.

- If the Commission finds that the costs debited to the Applicants' Pipeline Safety and Reliability Memorandum Accounts ("PSRMAs") are reasonable so that the costs may be recovered from ratepayers, the Commission should permit the Applicants to transfer their PSRMA balances as a debit to their PSEPCRAs and to recover the balances through their "year one" PSEP Surcharges with collected revenues being credited to their PSEPCRAs.

- The Applicants should be required to submit their proposed annual PSEP Update Reports through an advice letter.

- If the Commission elects to approve the proposal for Backbone Transmission Service ("BTS") reservation charge credits, the cost of offering the credits should be recovered through the Backbone Transmission Balancing Account ("BTBA") from BTS customers.

- No "pre-engineering" costs should be incurred in Phase 1A for the proposed 36-inch replacement of Line 1600 that is deferred to Phase 1B.

II. BACKGROUND.

In the "Background" section of their Opening Brief, the Applicants fail to recognize a central feature of both D.11-06-017[13] and the PSEP as presented by their witnesses. Both D.11-06-017 and the PSEP as presented by the witnesses contemplate a two-step process.

The first step is to complete "work in response to the Natural Transportation Board's January 3, 2011, recommendations and the Commission's Resolution L-410"[14] in Class 3 and 4 and Class 1 and 2 High Consequence Areas by pressure testing or replacing natural gas transmission pipelines "that have not been tested or for which reliable records are not available."[15] This first step is an "interim requirement."[16] For purposes of meeting the interim requirement, "a pressure test record must include all elements required by the regulations in effect when the test was conducted."[17]

Consistent with the "interim requirement" of D.11-06-017, the Applicants' witnesses propose that in Phase 1 of the PSEP the Applicants will pressure test or replace all transmission pipeline segments in Class 3 and 4 areas and Class 1 and 2 High Consequence Areas for which they do not have sufficient documentation of pressure testing to at least 1.25 times MAOP.[18] The Applicants' witnesses do not propose that pressure test records or the pressure test itself

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[13] D.11-06-017 (June 9, 2011).

[14] D.11-06-017, p. 31 (June 9, 2011) (Ordering Paragraph 2).

[15] *Ibid*, p. 18.

[16] D.11-06-017, p. 18.

[17] *Ibid*, pp. 14, 18 (Ordering Paragraph 3).

[18] Ex. SCG-4, p. 50 (Applicants/Schneider).

must meet the "modern standards" of 49 CFR Part 192 for purposes of Phase 1. It is enough if the records show a pressure test to at least 1.25 times MAOP insofar as this is the stability threshold for long seams.[19] If the Applicants had pressure tested all of their natural gas transmission pipelines in Class 3 and 4 and Class 1 and 2 High Consequence Areas and retained records of the testing, there would be no need for replacement or pressure testing of the pipelines during Phase 1 regardless of whether the pipelines had been pressure tested to meet the "modern standards" in 49 CFR Part 192 or not.

The second step mandated by D.11-06-017 is to bring "all natural gas transmission pipelines… into compliance with modern standards of safety."[20] Accordingly, during the Applicants' Phase 2, the Applicants would pressure test or replace pre-1970 pipelines that were pressure tested to pre-1970 standards with documentation of the tests but were not tested to "modern standards."[21] They would also pressure test or replace pipeline segments in Class 1 and 2 areas that lack documentation of a pressure test to 1.25 times MAOP.

Instead of recognizing the two-step process in the "Background" section of their Opening Brief, the Applicants say that D.11-06-017 requires "a plan to test or replace all pipeline segments that do not have sufficient documentation of pressure testing to satisfy the requirements of 49 CFR 192.619(a)(b) or (d)."[22] This description fails to recognize that for purposes of the first step contemplated in D.11-06-017, all that is required is a record of a pressure test that contains the elements that were required by the regulation that was in effect

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[19] D.11-06-017, p. 11, footnote 14; Tr. 417 (Applicants/Schneider).

[20] D.11-06-017, p. 18.

[21] Ex. SCG-4, p. 51 (Applicants/Schneider).

[22] The exclusion of 49 CFR 192.619(c) means that California gas utilities may no longer rely on records of operating history to establish MAOP but must instead locate records of pressure testing in accordance with Subpart J standards or conduct such pressure tests or replace the pipeline. Ex. SCG-01 (Morrow) at 3.

when the test was conducted, not a record of a pressure test that contains the elements required after 1970 by 49 CFR Part 192.

There is a significant difference between requiring testing or replacing pipelines in populated areas that lack documentation of a test to "modern standards" in 49 CFR Part 192 and requiring testing or replacing of pipelines in populated areas that lack documentation that contains the elements that were required by the regulation that was in effect when the test was conducted. If Phase 1 is only for pressure testing or replacing pipelines in populated areas that lack sufficient documentation of a pressure test that met regulations that were in effect when the test was conducted, the shareholders should be required to bear the cost of retesting or replacing the pipeline if the documentation is not available. If the Commission's regulations required pressure testing with record retention, presumably the Applicants conducted post-construction pressure tests with the cost of the tests being borne by ratepayers. Ratepayers should not be required to bear the cost of a second round of pressure testing that is needed only because the Applicants failed to comply with the Commission's regulation requiring that they retain records of the pressure testing.

III. RESPONSIBILITY FOR PHASE 1 COSTS.

A. Applicable Standards and Burden of Proof.

1. The Applicants misstate the standard of evidence.

The Applicants state that "the applicable evidentiary standards to be employed in this proceeding are set forth in Rule 13.6 of the Commission's Rules of Practice and Procedure."[23] That statement is false. Although Rule 13.6 contains some procedural rules regarding tender of evidence and evidentiary rulings, Rule 13.6 does not provide the standard of evidence that must

[23] Applicants Opening Brief, p. 15 (footnote omitted).

be met by the Applicants in order for them to bear their burden of proof in this proceeding. Rule 13.6 provides as follows:

> **13.6 (Rule 13.6) Evidence.**
>
> (a) Although technical rules of evidence ordinarily need not be applied in hearings before the Commission, substantial rights of the parties shall be preserved.
>
> (b) When objections are made to the admission or exclusion of evidence, the grounds relied upon shall be stated briefly.
>
> (c) The Commission may review evidentiary rulings in determining the matter on its merits. In extraordinary circumstances, where prompt decision by the Commission is necessary to promote substantial justice, the assigned Commissioner or Administrative Law Judge may refer evidentiary rulings to the Commission for determination.
>
> (d) Formal exceptions to rulings are unnecessary and need not be taken.
>
> (e) An offer of proof for the record shall consist of a statement of the substance of the evidence to which objection has been sustained.[24]

As discussed in SCGC's Opening Brief,[25] the Applicants must meet their burden of proof by demonstrating that their positions and proposals are supported by a preponderance of the evidence.[26] Preponderance of the evidence is usually defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[27]

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[24] 20 California Code of Regulations §13.6.

[25] SCGC Opening Brief, p. 10.

[26] D.06-05-016, p. 8 (May 11, 2005).

[27] D.08-12-058, *citing* Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184.

2. The Applicants bear the burden of proving that they should be permitted to recover the cost of pressure testing or replacing post-1961 pipelines.

The Applicants' sole discussion about who bears the burden of proof in this proceeding is directed to the question of who bears the burden of proof to demonstrate that shareholders rather than ratepayers should bear pressure testing or replacement costs. The Applicants claim that "intervenors" should bear the burden of showing who should bear the responsibility for bearing such costs.[28] The Applicants claim that they should not be required to bear the burden of proof for recovery of any pressure testing or replacement cost in this proceeding because none of the pressure testing or replacement is "the result of any violation by SoCalGas or SDG&E of a Commission decision or order, or any other law or regulation."[29]

The Applicants' claim is false. As SCGC explained in detail in its Opening Brief, Commission regulations have required post-construction pressure tests of pipelines since July 1, 1961. Likewise, the Commission's regulations have explicitly required pipeline operators to retain records of the pressure tests for the useful life of the pipeline since July 1, 1961.[30] Section 463(b) of the Public Utilities Code requires the Commission to disallow any expense if a utility fails to maintain sufficient records:

> (b) 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 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

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[28] Applicants Opening Brief, pp. 17-19.

[29] Applicants Opening Brief, p. 18.

[30] SCGC Opening Brief, pp. 10-14.

> preparing or maintaining the records or the extent of recordkeeping required to adequately evaluate those costs.[31]

During Phase 1 of the PSEP, the Applicants would pressure test or replace pipelines in Class 3 and 4 areas and Class 1 and 2 High Consequence Areas that do not have sufficient documentation to validate a post-construction pressure test to at least 1.25 times MAOP.[32] Some of those pipelines were constructed after July 1, 1961.[33] But for the Applicants' failure to comply with explicit Commission pressure testing and record retention regulations regarding pipelines constructed on or after July 1, 1961, the Applicants would not have to pressure test or replace any pipelines constructed after July 1, 1961, in Class 3 and 4 areas or Class 1 and 2 High Consequence Areas during Phase 1 of the PSEP. The need to pressure test or replace the post-1961 pipelines during Phase 1 of the PSEP is the direct result of the Applicants' violation of pressure test and record retention requirements that have been effective continuously since July 1, 1961. Accordingly, the Applicants bear the burden of proving that ratepayers rather than shareholders should bear the costs of pressure testing or replacing the post-1961 pipeline segments.

3. Shareholder responsibility for bearing the cost of Phase 1 pressure testing or replacing pipelines constructed after July 1, 1961, should not be shifted to another proceeding.

Suspecting that they would be required to bear the burden of proof to show why ratepayers rather shareholders should bear the cost of pressure testing or replacing pipelines in Phase 1 which do not have sufficient documentation of a pressure test to 1.25 times MAOP, the Applicants attempt to defer consideration of the issue, claiming that shareholder responsibility

[31] Cal. Pub. Util. Code §463(b).

[32] Ex. SCG-04-, p. 50 (Applicants/Schneider).

[33] SCGC Opening Brief, pp. 14-18.

for any Phase 1 PSEP costs "should be considered part of another proceeding (or perhaps another phase of this proceeding)…."[34]

There is no need to defer the issue to another proceeding. The record in this proceeding shows that Commission regulations have been in effect continuously since July 1, 1961, requiring post-construction pressure of transmission pipelines and retention of records of the tests for the useful life of the pipeline.[35] Furthermore, the record is replete with the Applicants' admissions that they lack sufficient documentation showing that various pipeline segments that were constructed after July 1, 1961, in Class 3 and 4 areas and Class 1 and 2 High Consequence Areas were pressure tested to at least 1.25 times MAOP.[36]

Insofar as the record in this proceeding contains evidence of Commission regulations that imposed post-construction pressure testing and record retention obligations on the Applicants as of July 1, 1961, and the record contains the Applicants' admissions that they failed to comply with the explicit terms of the regulations, there should be no deferral of shareholder responsibility for pressure testing or replacing pipeline segments in Class 3 and 4 areas or Class 1 and 2 High Consequence Areas that lack sufficient documentation of post-construction pressure testing to 1.25 times MAOP.

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

The Applicants misstate some of the safety standards that applied to transmission pipelines in California after the Department of Transportation ("DOT") first issued the pipeline safety regulations in 49 CFR Part 192 in 1970.

[34] Applicants Opening Brief, p. 21.

[35] *See* SCGC Opening Brief, pp. 10-14.

[36] *See* Ex. SCG-18, p. 12 (Applicants/Schneider) (1961-70 pipelines); Ex. SCG-02, p. 18 (Applicants/Morrow) (post-1970 vintage pipelines).

1. The Applicants misstate the pressure test ratios that applied in California after Commission adoption, with strengthening, of DOT regulations.

The Applicants misstate the pressure test ratios that applied in California after the Commission adopted the DOT pipeline safety regulations in 1970. The Applicants state: "For pipe installed after November 11, 1970, test pressure ratios were 1.1, 1.25, and 1.5 in Classes 1, 2, and 3 or 4, respectively. For pipe installed and tested prior to November 12, 1970, the test ratio for Classes 3 and 4 was 1.4…."[37] The Applicants then state: "These pressure testing requirements were incorporated into GO 112."[38] This statement is false.

The pressure test requirements that were adopted by DOT in 1970 were not incorporated into California regulations without modification. When the Commission adopted 49 CFR Part 192 to supplement the then-applicable General Order No. 112-B, the Commission ordered that all standards in General Order No. 112-B that were additional to or more stringent than the new 49 CFR Part 192 standards would remain in effect.[39] Accordingly, strengthened provisions of 49 CFR Part 192 were incorporated into the Commission's regulations in General Order No. 112-C. The General Order No. 112-C pressure testing requirements were as follows:

	Factor	
Class Location	Segment Installed Before (July 1, 1961)	Segment Installed After (June 30, 1961)
1	1.1	1.25
2	1.25	1.25
3	1.4	1.5
4	1.4	1.5[40]

[37] Applicants Opening Brief, p. 28 (footnotes omitted).

[38] *Ibid* (footnote omitted).

[39] *See* D.78513, p. 3 (April 12, 1971).

[40] D.78513, p. 133 (April 2, 1971) (General Order No. 112-C).

Thus, for pipe installed after November 11, 1970, the test pressure factors required for pipeline segments in Class 1 locations continued to be 1.25 times MAOP in California instead of 1.1 times MAOP as allowed under the DOT regulation. For pipe installed after June 30, 1961, but before November 12, 1970, the pressure test factor that applied to pipeline segments in Class 3 and 4 areas continued to be 1.5 times MAOP in California rather than 1.4 times MAOP as allowed under the DOT regulations. California pipeline safety requirements were not weakened to conform to the Federal regulations until the Commission adopted General Order 112-E in 1995.[41]

2. The Applicants falsely claim that DOT regulations do not require retention of strength test records.

The Applicants argue that under 49 CFR 192.619 that were "four possible alternatives for establishing the MAOP that would not necessarily have required any documentation of a prior post-installation pressure test…."[42] The Applicants identify these "four possible alternatives for establishing the MAOP" as follows:

- Section 192.619(a)(1) recognized the design pressure of the weakest component in accordance with Subparts C and D. In this case the MAOP would be based on manufacturer's component pressure ratings or engineering calculations using specified material strength and wall thickness dimensions.

- Section 192.619(a)(3) recognized the highest pressure to which the pipeline had been subjected during the five years preceding July 1, 1970.

- Section 192.619(a)(4) recognized 85% of the highest test pressure to which the pipe had been subjected, either in the pipe mill or in the field. If no field test was documented, the mill test would govern. The operator could determine the pipe mill test pressure if he knew the pipe product specification and year of manufacture.

[41] D.95-08-053 (August 11, 1995).

[42] Applicants Opening Brief, p. 35.

- Section 192.619(a)(5) allowed the operator to determine the maximum safe pressure considering the history of the segment, known corrosion, and actual operating pressure. This might be used, for example, with an uncoated pipeline that had experienced general wall thinning due to corrosion.[43]

The Applicants then claim that the "four possible alternatives for establishing the MAOP" show that "regulators have accepted that not all records need necessarily be present."[44]

The Applicants' claim misleadingly implies that the DOT regulations do not require pressure test record retention. Nothing could be further from the truth. 49 CFR Part 192 specifically requires that no person may operate a pipeline segment before the pipeline segment has been tested[45] and that pipeline operators shall retain for the life of the pipeline a record of the tests that they performed for the life of the pipeline:"Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed…."[46]

The provisions from 49 CFR 192.619(a) subsections (1), (3), (4) and (5) that are quoted by the Applicants are not alternatives that relieve a pipeline operator of the obligation to pressure test a new transmission pipeline and to retain a record of the test for the life of the pipeline. Instead, they are alternatives that must be followed in establishing the MAOP for a pipeline if any of the alternatives would result in a MAOP that would be lower than the MAOP that is validated through the required pressure test.[47] All pipelines that are not grandfathered under 49

[43] The Applicants fail to identify the version of 49 CFR 192.619 that contains their claimed "four possible alternatives." The passage that the Applicants claim to be contained within 49 CFR 192.619(a)(4) was contained in 49 CFR 192.619(a)(5) in the 1970 version of the DOT regulation but it does not appear at all in the 2011 version. Ex. SCG-30 (1970 version); Ex. SCG-31 (2011 version). The text that the Applicants claim to be from 18 CFR 192.619(a)(5) appeared in 49 CFR 192.619(a)(6) in the 1970 version of the DOT regulation, but it appears as 49 CFR 192.619(a)(4) in the 2011 version. Ex. SCG-30 (1970 version); Ex. SCG-31 (2011 version).

[44] Applicants Opening Brief, p. 38.

[45] 49 CFR 192.503(a), Ex. SCG-30 (1970 version), Ex. SCG-31 (2011 version).

[46] 49 CFR 192.517, Ex. SCG-30 (1970 version), Ex. SCG-31 (2011 version).

[47] 40 CFR 192.619(a), Ex. SCG-30 (1970 version); Ex. SCG-31 (2011 version).

CFR 192.619(c) must be pressure tested, and records of the tests must be retained as required by 40 CFR 192.517.

C. Cost Responsibility.

The Applicants fail to offer any convincing arguments that shareholders should not be required to bear the Phase 1 costs of pressure testing or replacing pipeline segments constructed after July 1, 1961, in Class 3 and 4 areas and Class 1 and 2 High Consequence Areas for which the Applicants lack sufficient documentation of pressure testing to 1.25 times MAOP.

1. The Applicants misstate SCGC's position on bringing pre-1970 pipelines to "modern standards."

The Applicants claim that that SCGC argues "that compliance with pre-1970 regulations," meaning General Order No. 112 that has been effective since July 1, 1961, "would obviate the need to incur costs to pressure test or replace pipeline lacking documentation of a pressure test to Subpart J standards."[48] Likewise, the Applicants contend that SCGC "ignores the significance of the Commission's directive in Ordering Paragraph No. 4, which requires all in-service natural gas transmission pipelines to have documented pressure tests in accordance with Subpart J standards or to conduct such pressure tests or replace the pipeline."[49] Later the Applicants state that SCGC makes the "incorrect assumption that if SoCalGas and SDG&E can just locate pre-1970 pressure test records, the utilities will not be required to replace or pressure test their older pipelines in order to satisfy the new modern standards."[50]

The Applicants mischaracterize SCGC's position. SCGC recognizes that the Commission ordered in D.11-06-017 that "all natural gas transmission pipelines in service in

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[48] Applicants Opening Brief, p. 38.

[49] Applicants Opening Brief, p. 46.

[50] Applicants Opening Brief, p. 49.

California must be brought into compliance with modern standards for safety."[51] Likewise, SCGC recognizes the differences between the requirements established in 1961 in General Order No. 112 and the requirements established in 1970 in 49 CFR Part 192 regarding, particularly, the duration of a pressure test and the test records that must be retained.[52]

Rather than contending that pre-1970 pipelines that have records of pressure testing to 1.25 times MAOP would not need to be pressure tested or replaced to meet 49 CFR Part 192 "modern standards" under D.11-06-017, SCGC understands D.11-06-017 to require that pre-1970 pipelines that have documentation of testing but not testing to 49 CFR Part 192 standards shall be brought to "modern standards" as a second step after pipelines in populated areas which lack documentation of pressure testing are addressed.

Accordingly, SCGC does not contend that shareholders should be responsible for bearing the cost of pressure testing or replacing pre-1970 pipelines that were pressure tested in accordance with standards that were applicable at the time of testing with records being retained but which have to be retested to meet 49 CFR Part 192 standards. Instead, SCGC supports the Applicants' witness Schneider's four alternatives to pressure testing or replacing pre-1970 pipelines, particularly witness Schneider's first alternative under which a post-construction pressure test to at least 1.25 times MAOP with records showing test medium and test pressure would be sufficient so that testing to 49 CFR Part 192 standards would not be required in Phase 2.[53]

The costs for which shareholders should bear responsibility are the costs of Phase 1 pressure testing or replacing pipeline segments that were constructed after General Order No.

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[51] D.11-06-017, p. 18 (June 9, 2011).

[52] SCGC Opening Brief, pp. 10-14.

[53] Ex. SCG-04, p. 46 (Applicants/Schneider) *See* SCGC Opening Brief at 40-48.

112 became effective on July 1, 1961, that are in Class 3 and 4 areas or Class 1 and 2 High Consequence Areas, and for which the Applicants lack sufficient documentation of pressure testing to 1.25 times MAOP. Thus, shareholders should be responsible for pressure testing or replacing about nine miles of 1961-1970 vintage pipeline segments and eight miles of post-1970 pipeline segments for which the Applicants' lack sufficient documentation of pressure testing.[54] But for the failure of the Applicants to retain records of the testing of those miles of pipelines, the retesting or replacing of the pipelines would not have to be done in Phase 1.

2. Requiring 100 percent compliance with record retention regulations is reasonable.

The Applicants contend that they should not be responsible for "perfect maintenance of test records."[55] However, the record retention requirements in General Order No. 112[56] and 49 CFR 192.517 contain explicit requirements about maintaining test records for the useful life of a pipeline. Applicants presumably recovered the costs of post-construction pressure tests of post-1961 pipelines from ratepayers. In the absence of the records required by General Order No. 112 and 49 CFR Part 192 the Applicants must re-test or replace pipeline segments that have already been pressure tested with ratepayer funding. The retention of records is essential to assure that ratepayers will not be called upon to fund retesting or replacing pipelines that have already been pressure tested. Thus, it is reasonable to require pipeline operators to retain pressure test records for the useful life of a pipeline, and is reasonable to require shareholders to bear the cost of retesting or replacing pipeline segments of the pipeline operators fail to retain records as required by explicit regulation.

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[54] SCGC Opening Brief, pp. 16-18.

[55] Applicants Opening Brief, p. 50.

[56] General Order No. 112, Section 841.417, Records; Section 301.1.

In response, the Applicants argue that "the Commission has previously stated '100% compliance… at all times is not realistic,'"[57] citing D.04-04-065. However, D.04-04-065 does not support the Applicants' contention. D.04-04-065 addressed whether it was an "achievable standard" to insist that a utility maintain its system "in complete conformance" with all of the Commission's safety general orders. The Commission found that it is "impossible for a utility to keep a distribution system in full compliance with the safety GOs at all times."[58] Unlike the situation that was addressed in D.04-04-065, this proceeding involves specific and narrowly drawn regulatory requirements, namely, the record retention provisions of General Order No. 112 and 49 CFR Part 192. It is reasonable to expect 100 percent compliance with those provisions.

3. Ratepayer contributed funds should not be used for pressure testing or replacing post-1970 pipeline segments for which the Applicants lack sufficient documentation of post-construction pressure testing.

The Applicants contend that they "are not seeking cost recovery through our PSEP" for pressure testing or replacing pipeline segments that were constructed after 1970 but which lack sufficient documentation of a pressure test to 1.25 times MAOP.[59] That leaves them to argue that "there is no decision or directive needed from the Commission in this proceeding with respect to pipelines installed by SoCalGas and SDG&E after 1970."

Although the Applicants' PSEP does not include the cost of pressure testing or replacing pipelines constructed after 1970, that does *not* mean that shareholders would bear the cost of pressure testing or replacing post-1970 pipeline segments for which the Applicants lack sufficient documentation of pressure testing. The Applicants' witness Morrow clarified on

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[57] Applicants Opening Brief, p. 41 (footnote omitted).

[58] D.04-04-065, p. 62 (Finding of Fact 10).

[59] Applicants Opening Brief, p. 48.

cross-examination that the cost of pressure testing or replacing post-1970 pipelines that lack sufficient documentation of post-construction pressure testing will be "funded through our existing O&M and capital budget that's been established for the utility."[60] Witness Morrow explained further that "we are seeking the full recovery of our capital investments here, yes."[61]

Given witness Morrow's testimony that the Applicants intend to use ratepayer contributed funds to pressure test or replace post-1970 pipeline segments that lack sufficient documentation of post-construction pressure testing, there is a clear need for a decision from the Commission regarding funding for such segments. Given that the need to pressure test or replace post-1970 pipeline segments is the direct consequence of the Applicants' failure to comply with the explicit record retention requirements of 49 CFR 192.517, it is necessary for the Commission's decision in this proceeding to address cost responsibility for remediation of post-1970 pipeline segments and to find that the shareholders rather than ratepayers shall bear the cost responsibility for the remediation of those segments.

4. Imposing cost responsibility on shareholders for remediation of post-1961 pipelines would not be disproportionate.

The Applicants contend that SCGC's proposal to require shareholders to bear cost responsibility for remediation of post-1961 pipelines is "utterly lacking in proportionality…."[62] To the contrary, SCGC's proposal regarding shareholder cost responsibility is, if anything, disproportionately modest. Given the testimony of the Applicants' witnesses on cross-examination, it now appears that only about nine miles of 1961-1970 vintage pipeline segments

[60] Tr. 103 (Applicants/Morrow).

[61] Tr. 106 (Applicants/Morrow).

[62] Applicants Opening Brief, p. 51.

lack sufficient documentation of pressure testing.[63] Only seven[64] or eight miles of post-1970 pipelines were found by the Applicants to require remediation.

Applicants estimated that the total pressure testing O&M cost and direct capital replacement cost for *twenty* miles of 1961-1970 pipeline segments, which is more than the combined mileage for 1961-1970 pipeline segments and post-1970 segments, would be $73.4 million.[65] That is a small fraction of the $1.7 billion direct cost the Applicants propose for all Phase 1A work.[66]

Given the explicit record retention requirements of General Order No. 112 and Subpart J, and given that it should be presumed that ratepayers have already paid for post-construction pressure tests of the nine miles of 1961-1970 vintage pipeline segments and the seven or eight miles of post-1970 segments, it is entirely reasonable to require shareholders to bear whatever the ultimate cost of pressure testing or replacing these pipeline segments might be. Imposing cost responsibility for remediation of those pipeline segments will provide an incentive to the utilities to make every effort to contain the costs of retesting or replacing the pipeline segments.

5. Requiring shareholders to bear the costs of remediating post-1961 pipeline segments provides correct financial incentives.

The Applicants contend that "there must be a financial incentive to design and implement the desired safety improvements in a manner that avoids excessive costs…." That statement is not true. A key component of the regulatory compact is that a regulated utility will provide service that is safe and reliable and will avoid excessive costs in return for the opportunity to earn a reasonable return.

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[63] *See* SCGC Opening Brief, p. 16.

[64] Ex. SCG-02, p. 18, footnote 16 (Applicants/Morrow).

[65] Ex. SCGC-1. p 14 (SCGC/Yap).

[66] Ex. SCG-09, pp. 103-104 (Applicants/Reyes).

To the extent to which the Applicants require a financial incentive, requiring shareholders to bear the costs of remediating post-1961 pipeline segments that lack sufficient documentation of pressure testing provides the right financial incentive. If the Applicants pressure test pipelines but fail to comply with the record retention requirements that are applicable under General Order No. 112 or 49 CFR Part 192, making the shareholders responsible for retesting or replacing the involved pipeline segments will incentivize the Applicants to avoid future record retention lapses.

6. Requiring shareholders rather than ratepayers to bear the costs of remediating post-1961 pipeline segments that lack sufficient documentation of pressure testing would not result in retroactive application of a new and higher standard.

The Applicants contend that SCGC's proposal for shareholders rather than ratepayers to bear costs associated with remediating post-1961 pipeline segments in Class 3 and 4 and Class 1 and 2 High Consequence Areas that lack sufficient documentation of pressure testing to 1.25 times MAOP would result in retroactive application of a standard.[67] Under SCGC's proposal in this proceeding, there would be no retroactive application of any regulatory standards.

Under General Order No. 112, new pipeline segments were required to be pressure tested with retention of records of test medium and test pressure. If the Applicants complied prospectively with the regulations that became effective on July 1, 1961, there would be no post-1961 pipelines to remediate during Phase 1 of the PSEP, and shareholders would not be required to bear any costs of remediation. There is only a prospective application of standards that became effective in July 1, 1961.

Nor is there any "regulatory opportunism" under SCGC's proposal. The Applicants claim there would be "regulatory opportunism," which they define as being "a situation in which

[67] Applicants Opening Brief, p. 57

a regulator leaves open the possibility that it will not allow utilities to recover the cost of sunk capital."[68] Under SCGC's cost responsibility proposal in this proceeding, shareholders will be permitted to recover costs associated with sunk capital. They will only be precluded from recovering from ratepayers the cost of retesting or replacing pipeline segments for which ratepayers have already borne pressure testing costs.

7. Requiring shareholders to bear the cost for remediating post-1961 pipeline segments would not violate the taking clauses of the US and California Constitutions.

The Applicants contend that SCGC would require them "to conduct certain tests and install new pipelines yet *receive no compensation whatsoever* for that work or property."[69] They contend this "would surely violate…state and federal constitutional standards."[70] However, the Applicants also point out: "The taking is unconstitutional only if the property holder does not receive just compensation."[71]

The Applicants received just compensation for conducting post-construction pressure tests when they pressure tested pipeline segments the first time under General Order No. 112 or 49 CFR Part 192 and passed the pressure testing costs through to ratepayers. It would be unjust and unreasonable for the Applicants to recover costs for retesting or replacing post-1961 pipelines that require retesting or replacement only because the Applicants failed to comply with the explicit record keeping requirements of General Order No. 112 and 49 CFR Part 192. Under the Public Utilities Code, "all charges demanded or received by any public utility… for any product or commodity furnished or to be furnished or any service rendered or to be rendered

[68] Applicants Opening Brief, p. 55 (footnote omitted).

[69] Applicants Opening Brief, p. 63 (footnote omitted; emphasis in original).

[70] *Ibid*, p. 64.

[71] *Ibid*, p. 64 (footnote 249).

shall be just and reasonable."[72] Preventing a utility from unjustly charging twice for pressure testing would not be an unconstitutional taking.

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

As explained in SCGC's Opening Brief,[73] the Applicants propose to pressure test or replace pipeline segments in Class 3 and 4 and Class 1 and 2 High Consequence Areas which do not have sufficient documentation of a hydrostatic pressure test, a pressure test using the medium rather than water, or an in-service pressure test to at least 1.25 times MAOP.[74] Work on these segments that lack a pressure test of any sort to at least 1.25 times MAOP would be done during Phase 1A, which spans the years 2012 through 2015, except for "pipeline segments that would otherwise be addressed in Phase 1A, but which cannot be addressed in the near-term due to a need to construct new infrastructure to maintain service during pressure testing."[75] Work on those segments would be completed during Phase 1B which spans the years 2016 through 2021.[76] The only pipeline that contains segments that should be done during Phase 1 but which are assigned to Phase 1B is Line 1600 in the SDG&E service territory.[77]

The Applicants propose to pressure test or replace pipeline segments that are in Class 1 and 2 areas that do not have sufficient documentation of a post-construction pressure test to 1.25 times MAOP in Phase 2.[78] Also, all transmission lines that have documentation of a hydrostatic pressure test, a pressure test using a medium other than water, or an in-service pressure test to at

[72] Public Utilities Code §451.

[73] SCGC Opening Brief, pp. 18-21.

[74] Ex. SCG-18, p. 12 (Applicants/Schneider).

[75] Ex. SCG-4, p. 60 (Applicants/Schneider).

[76] Ex. SCG-2, p. 19 (Applicants/Morrow).

[77] Tr. 450 (Applicants/Schneider).

[78] Ex. SCG-04, p. 51 (Applicants/Schneider).

least 1.25 times MAOP will be pressure tested or replaced to bring the pipeline segments to "modern standards" in Phase 2, unless alternatives proposed by the Applicants' witness Schneider are approved.[79] The Applicants' Phase 2 starts in 2016 at the same time as Phase 1B and continues past 2021.[80]

A. Decision-Making Process (Test or Replace, Decision Tree).

As discussed in SCGC's Opening Brief,[81] the Applicants developed a decision tree to determine the treatment to be given to pipeline segments in Class 3 and 4 areas and Class 1 and 2 High Consequence Areas that do not have sufficient documentation of strength testing to at least 1.25 times MAOP.[82] In the decision tree, all Phase 1 pipeline segments fall into one of three categories: (1) pipeline segments that are 1,000 feet or less in length, (2) pipeline segments greater than 1,000 feet in length that can be removed from service for pressure testing, and (3) pipeline segments greater than 1,000 feet in length that cannot be removed from service for pressure testing.[83]

For pipeline segments that are 1,000 feet or less in length, Applicants believe that it would typically be more cost effective to abandon and replace the segments than to perform a pressure test.[84] Accordingly, all PSEP Phase 1 segments that are 1,000 or less in length are scheduled for replacement followed by abandonment[85] unless, as discussed below, the

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[79] *Ibid*.

[80] Ex. SCG-02, p. 20 (Applicants/Morrow).

[81] SCGC Opening Brief, pp. 21-24.

[82] Ex. SCG-04, p. 61, Figure IV-1 (Applicants/Schneider).

[83] *Ibid*, p. 52.

[84] *Ibid*, p. 53.

[85] *Ibid*, p. 54.

Commission approves non-destructive examination as an alternative to replacement of short segments.[86]

For Phase 1 pipeline segments that are greater than 1,000 feet, the decision to replace rather than pressure test a segment can have an enormous effect on direct costs and the revenue requirement that is recovered by ratepayers. As discussed in SCGC's Opening Brief, the direct cost of replacing transmission pipelines on average is eleven times greater than the direct cost of pressure testing.[87] The direct of replacing high pressure distribution lines, which are considered to be transmission lines for PSEP purposes, is sixteen times greater than the cost of pressure testing.[88] Capitalizing the direct costs of replacing pipelines increases the total cost to ratepayers over the life of the asset by about four times.[89]

Recognizing the substantial direct cost and revenue requirement implications of a decision to replace rather than pressure test a pipeline segment, the Commission directed that the Applicants PSEP "must set forth criteria on which pipeline segments were identified for replacement instead of pressure testing."[90]

The sole criteria that the Applicants offer in their direct testimony for determining whether a pipeline segment should be replaced instead of pressure tested was stated in the form of a question that would be asked about pipeline segments that area greater than 1,000 feet: "Can pipeline be taken out of service with manageable customer impact?"[91] In their rebuttal testimony, Applicants went further and presented a "Replacement Decision Tree" for Phase 1A pipeline segments greater than 1,000 feet in length. The Applicants would ask a series of

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[86] *Ibid*.

[87] SCGC Opening Brief, p. 25.

[88] *Ibid*.

[89] *Ibid*.

[90] D.11-06-017, p. 32 (Ordering Paragraph 6).

questions about mitigating customer impacts and cost comparisons.[92] Additionally, the Applicants identified five "principles" that would be followed in determining whether to replace rather than pressure test a Phase 1A pipeline segment that is greater than 1,000 feet in length.[93]

The Applicants admit that their proposed "Replacement Decision Tree" and the associated five "principles" are not clear-cut criteria that would mechanically drive a "yes/no" decision to replace rather than pressure test: "Applicants witness Phillips testified that 'we don't think that it is possible at this point to produce something that is yes/no on a Decision Tree.'"[94]

Given that the Applicants' proposed "Replacement Decision Tree" and associated "principles" for determining whether to replace or pressure test pipeline segments greater than 1,000 feet in length in Phase 1A leave substantial leeway for the Applicants to exercise judgment in deciding whether to replace or pressure pipeline segments, SCGC proposed an Expedited Application Docket ("EAD") process for obtaining expeditious Commission review for decisions to replace rather than pressure test Phase 1A pipeline segments that are greater than 1,000 feet in length on a case-by-case basis.[95]

1. Utilizing the Expedited Application Docket procedure to review decisions to replace segments greater than 1,000 feet in length would not result in "hundreds of new applications."

The primary objection of the Applicants to SCGC's proposal for Commission review of Phase 1A decisions to replace rather than replace pipeline segments greater than 1,000 feet in length is that requiring EAD review would add "hundreds of new applications to the

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[91] Ex. SCG-04, p. 61, Figure IV-1 (Applicants/Schneider).

[92] SCG-20, p. 8, Figure 1 (Applicants/Phillips).

[93] Ex. SCG-20, pp. 8-9 (Applicants/Phillips).

[94] Tr. 1147-1148 (Applicants/Phillips).

[95] SCGC Opening Brief, pp. 24-36.

Commission's already burdened docket…."[96] The Applicants' allegation is flatly false. Requiring EAD review of the Applicants' Phase 1A decisions to replace pipeline segments greater than 1,000 feet in length would not result in "hundreds of new applications."

a. Phase 1A includes 128 replacement projects.

The Applicants' witness Rivera identified the Applicants' Phase 1 replacement projects in his workpapers.[97] Witness Rivera identified 135 Phase 1A replacement projects, excluding the Line 1600 replacement which is deferred to Phase 1B.[98] However, as discussed in SCGC's Opening Brief,[99] five of the projects that witness Rivera identified as being replacement projects were subsequently identified by the Applicants as "scope no longer in Phase 1A"[100] Two SDG&E projects were identified as "scope being addressed independent of PSEP."[101] If the five SoCalGas pipeline segments that were subsequently identified as "scope no longer in Phase 1A" and the two SDG&E pipeline segments that were subsequently identified as "Scoping addressed independent of PSEP" are subtracted from witness Rivera's list of 135 replacement projects, the number of replacement projects that would be pursued in Phase 1A drops from 135 to 128 projects.

b. Only 74 of the Phase 1A replacement projects involve pipeline segments over 1,000 feet in length.

SCGC does not propose EAD review of replacements of pipeline segments that are less than 1,000 feet in length. Fifty four of the 128 projects that the Applicants continue to include in Phase 1A involve replacement of projects that are less than 1,000 feet (0.19 miles) in length.

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[96] Applicants Opening Brief, p. 104.

[97] Ex. SCG-32, pp. WP-IX-23 through WP-IX-1-37; Ex. SCG-04.

[98] *Ibid*.

[99] SCGC Opening Brief, p. 32.

[100] Comments in Response to Assigned Commissioner's Rulings' and Supplement to Request for Memorandum Account, R.11-02-019 and A.11-11-002 (unconsolidated, Attachment A).

Only one has a direct cost that exceeds $1 million.[102] Only five have a direct cost over $500,000.[103] The average direct cost of the remaining 49 Phase 1A replacements of pipeline segments that are less than 1,000 feet in length is only $217,000.[104]

Subtracting the 54 Phase 1A replacement projects that would involve pipeline segments less than 1,000 feet in length from the total 128 replacement projects projected by the Applicants for Phase 1A leaves only 74 replacement projects for EAD review.

c. **Only 44 of the replacements of pipeline segments over 1,000 feet in length cost more than $5 million, but they represent 85 percent of Phase 1A replacement costs.**

The Applicants project that only 44 projects would have a direct cost exceeding $5 million.[105] However, those 44 projects that have a projected direct cost over $5 million represent 85 percent of what the Applicants project to be the total Phase 1A direct cost of replacement projects, excluding the cost of projects that are no longer included in Phase 1A and excluding costs for Line 1600 which should be left for Phase 1B.[106]

The Applicants state that the EAD procedure that was adopted by the Commission in the 1990s for reviewing anti-bypass discounted contracts "dealt with dozens of proposed contracts,"[107] indicating that "dozens" of EAD proceedings may be acceptable to the Applicants while "hundreds" would not be acceptable. EAD review of only 44 projects would be well within the range of the "dozens" that may be acceptable to Applicants. Given that EAD review of the 44 Phase 1A replacement projects that the Applicants project to have a direct cost over $5

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[101] *Ibid.*

[102] Ex. SCGC-4 (Pipeline 33-121 $1,406,500).

[103] Ex. SCGC-4 (Pipelines 33-121, plus Pipelines 35-405, 35-6416, 36-8-01-C, and 43-1106).

[104] *Ibid.*

[105] Ex. SCGC-4.

[106] *Ibid.*

[107] Applicants Opening Brief, p. 104.

million would result in review of projects that represent approximately 85 percent of the Phase 1A replacement costs projected by witness Rivera, as adjusted to eliminate projects that are no longer included in Phase 1A PSEP and to eliminate all Line 1600 costs, SCGC believes it would be an acceptable compromise to limit EAD review to the 44 projects that are estimated to have a direct cost in excess of $5 million.

The number of Phase 1A replacement projects could decrease even further if, as recommended by SCGC, the Commission determines that the Applicants' shareholders rather than ratepayers should be responsible for the cost of remediating post-1961 pipeline segments that lack sufficient documentation of a pressure test. The number of replacement projects in Phase 1A may decrease even further as a result of the Applicants' continuing search for pressure test records and as a result of the Applicants deciding on their own to pressure test rather than replace pipeline segments.

2. EAD review of Phase 1A replacements of segments more than 1,000 feet in length and costing over $5 million would not unduly delay PSEP work.

The Applicants contend that requiring the Applicants to submit an EAD application would delay execution of the PSEP.[108] The Applicants fail to recognize that if the EAD process applied only to Phase 1A decisions to replace pipeline segments greater than 1,000 feet in length that cost more than $5 million, pressure testing work would be unaffected, work on short segments would be unaffected, and work on projects costing less than $5 million would be unaffected. Thus, the majority of Phase 1A remediation projects would be unaffected.

Second, the Applicants fail to recognize how expeditious the EAD process would be. As explained in SCGC's Opening Brief,[109] the process would be accelerated by requiring the

[108] Applicants Opening Brief, p. 105.

[109] SCGC Opening Brief, pp. 29-30.

Applicants to provide a complete response to a Master Data Request at the time they submit their EAD application. After that, as described in D.92-11-052, thirty days would be allowed for protests, ten days for responses to protests, and forty-eight days for a workshop.[110] If no hearings were required, a decision would be issued within seventy five days of the day of the filing.[111]

Third, the Applicants fail to recognize that it would be likely that the first projects that would be submitted to the EAD process would be scrutinized more closely, with subsequent applications being processed more routinely.

3. The Applicants fail to provide an adequate substitute for a Commission review of Phase 1A replacement projects.

The Applicants propose that replacement projects be reviewed by a "Engineering Advisory Board" as an alternative to EAD review.[112] The Engineering Advisory Board would be wholly inadequate to protect ratepayer interests.

First, the Board would consist of a company representative, a representative of the Commission's Consumer Protection and Safety Division ("CPSD"), a representative of the Commission's Energy Division, and a fourth member who would be agreed upon by the first three members. Thus, there would be no ratepayer advocates on the Board even though the primary objective of reviewing Phase 1A replacement decisions is driven by the fact that replacing pipeline segments is much more costly and has a much greater total revenue requirement impact than pressure testing.

Second, the Board would not be independent of the Applicants. To the contrary, the Board would be dominated by the Applicants.

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[110] D.92-11-052, 1992 Cal. PUC LEXIS 765, *9; 46 CPUC2d 444; 139 P.U.R.4th 530 (November 23, 1992).

[111] *Ibid*.

Third, the operation of the Board would be opaque to the public, and there would be no opportunity for public participation.[113]

Fourth, the Board would be powerless. Even if the Board failed to confirm a replacement decision, the Applicants could proceed with the replacement, overriding the Board.[114]

B. Base Case.

1. The Applicants should not be permitted to accelerate work on Phase 2 miles to Phase 1A unless the Applicants obtain Commission approval of the acceleration on a case-by-case basis.

The Applicants propose to "accelerate" testing or replacing pipeline segments that would otherwise be pressure tested or replaced to meet "modern standards" in Phase 2.[115] Work on the Phase 2 segment would be accelerated to Phase 1A if the Phase 2 segment were located between two Phase 1A segments or were immediately adjacent to a Phase 1A segment.[116] The Applicants argue that acceleration could reduce the overall direct cost of replacements by 3.5 to 8.0 percent and could reduce the overall direct cost of pressure testing by 30-200 percent.[117]

The acceleration of work on pipeline segments that would otherwise be left to Phase 2 would greatly expand work to be done during Phase 1A. The Applicants propose to accelerate pressure testing of 170 miles to Phase 1A and to accelerate 110 miles of replacements to Phase 1A.[118] About 45 percent of the miles that would be pressure tested or replaced in Phase 1A would be "accelerated" miles.[119]

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[112] Applicants Opening Brief, pp. 101-102.

[113] Tr. 151 (Applicants/Morrow).

[114] Tr. 1181 (Applicants/Phillips).

[115] Applicants Opening Brief, pp. 110-112.

[116] *Ibid*, p. 111.

[117] *Ibid*, p. 112.

[118] Ex. 34R (Applicants).

[119] Ex. 34R (Applicants).

As discussed in SCGC's Opening Brief[120] and below, much of the Phase 2 work to address pipelines that have records of pressure testing but not to the standards of 49 CFR Part 192 could be avoided if the Commission approved some or all of the four alternatives sponsored by the Applicants' witness Schneider particularly, witness Schneider's alternatives 1 and 4. Accordingly, as proposed by TURN, the Applicants should not be permitted to accelerate work on Phase 2 miles to Phase 1A unless the Applicants obtain Commission approval of the acceleration on a project-specific basis.[121]

V. REASONABLENESS OF COST ESTIMATES.

As discussed in SCGC's Opening Brief,[122] the Applicants' estimates of Phase 1A pressure testing and replacement costs are so wildly inaccurate that they cannot provide a reasonable basis for calculating rates.

VI. ALTERNATIVES TO RESPLACEMENT OR PRESSURE TESTING.

The Applicants' witness Schneider proposed four alternatives to pressure testing or replacing pipelines that, in the absence of the alternatives, would have to be pressure tested. Inexplicably, the Applicants fail to address witness Schneider's first alternative in their Opening Brief. The Applicants discuss witness Schneider's second alternative but say that do not seek adoption of the alternative at this time.[123] They address and support witness Schneider's third and fourth alternatives, as does SCCGC.

The Commission should consider the alternatives proposed by witness Schneider in spite of the light treatment given to the alternatives in the Applicants' Opening Brief.

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[120] SCGC Opening Brief, pp. 40-48.

[121] TURN Opening Brief, p.

[122] SCGC Opening Brief, pp. 38-40.

[123] Applicants Opening Brief, p. 153.

A. Alternative One: Record of a Post-Construction Strength Test to at Least 1.25 Times MAOP.

Under witness Schneider's first alternative, for pipelines that were pressure tested prior to November 12, 1970, if the Applicants have a record of a post-construction strength test to at least 1.25 times MAOP and the record shows the test medium and test pressure, the pipeline segment would not have to be retested or replaced to meet the "modern standards" in 49 CFR Part 192. Witness Schneider's proposal is consistent with D.11-09-017, which ordered: "A pressure test must include all elements required by the regulation in effect when the test was conducted."[124] As discussed in SCGC's Opening Brief, requiring pressure testing of pipelines to at least 1.25 times MAOP is appropriate insofar as 1.25 times MAOP is the "stability threshold" for long seams.[125]

Permitting the Applicants to use witness Schneider's first alternative to validate long seams could save hundreds of millions of dollars that would otherwise have to be spent in the absence of the alternative in Phase 2 to retest or replace pre-1970 pipelines that have been pressure tested with the test records being retained but which were not pressure tested to "modern" post-1970 standards.

Permitting the Applicants to use witness Schneider's first alternative could also save hundreds of millions of dollars in Phase 1A. About 45 percent of the miles that are to be pressure tested or replaced in Phase 1A are "accelerated" miles[126] that would be pressure tested

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[124] D.11-09-017, p. 31 (Ordering Paragraph 3).

[125] SCGC Opening Brief, pp. 19-20, 42-43. The alternative would impose a more stringent requirement in Class 1 areas for which the pressure test factor was reduced from 1.25 times MAOP to 1.1 times in General Order No. 112-E.[125] Until 1995, the Commission required testing to 1.25 times MAOP in Class 1 areas, but when the Commission adopted General Order No. 112-E in 1995 to automatically adopt 49 CFR Part 192 revisions as they became effective, the federal requirement of a test pressure of 1.1 times MAOP Class 1 areas was applied to California.

[126] Ex 34R (Applicants).

or replaced in Phase 2 but which the Applicants propose to pressure test or replace in Phase 1A in conjunction with Phase 1A projects because some overall savings could be realized by doing the projects together.[127] Although some of the Phase 2 miles are in Class 1 and 2 non-High Consequence areas, most if not all of the "accelerated" projects are likely to be in Class 3 and 4 areas or Class 1 and 2 High Consequence Areas insofar as they would be done in conjunction with Phase 1A projects that by definition are in Class 3 and 4 areas or Class 1 and 2 High Consequence Areas.

If the "accelerated" miles are in Class 3 and 4 areas or Class 1 and 2 High Consequence Areas that would be pressure tested or replaced in Phase 2 but for the "acceleration," they are miles which have been pressure tested with test records being retained but which were not tested to post-1970 "modern" standards. Applying witness Schneider's first alternative to these miles that the Applicants would "accelerate" to Phase 1A could mean that the miles would not have to be pressure tested or replaced at all, resulting in a major reduction in Phase 1A costs.

B. Alternative 2: Lowering the MAOP to Less than or Equal to 72 Percent of the Highest Documented Actual Operating Pressure.

Witness Schneider proposed that the Applicants be permitted to lower the pressure in pre-November 12, 1970 pipelines to less than or equal to the highest actual operating pressure documented during the five years preceding the pressure reduction as an alternative to pressure testing or replacing the pipelines.[128] Reduction of the MAOP to less than or equal to 72 percent of the highest actual operating pressure experienced during the preceding five years would be equivalent to a safety factor of 1.39 times MAOP, providing an extra measure of safety above

[127] Applicants Opening Brief, p. 112.

[128] Ex. SCG-04, p. 46 (Applicants/Schneider).

1.25 times MAOP to "account for the fact that operational pressure measurements are not static and portions of the pipeline may not have experienced the measured highest pressure."[129]

Witness Schneider proposed in his direct testimony that the Commission should consider the second alternative "in the next phase of this proceeding."[130] However, on cross-examination, he recognized that "if we could address it sooner, then it could be used as an alternative in this first phase."[131] In their Opening Brief, the Applicants revert to witness Schneider's original position, saying that they "do not seek adoption of such rules at this time, but rather, ask the Commission to establish a stakeholder process of considering and developing such rules in Rulemaking 11-02-019."[132]

SCGC recommends that the Commission consider witness Schneider's second alternative in this proceeding for application in Phase 1A as well as in Phase 2. Witness Schneider's proposed pressure reduction could be used to address pipeline segments in Class 3 and 4 areas and Class 1 and 2 High Consequence Areas that lack sufficient documentation of pressure testing without incurring the cost of retesting or replacing the pipelines in Phase 1A. Witness Schneider's second alternative could also be used to avoid pressure testing or replacing pipelines in Phase 2.

C. Alternatives 3 and 4: Non-Destructive Examination and TFI.

The Applicants support witness Schneider's third alternative, non-destructive examination of, particularly, pipeline segments less than 1,000 feet in length.[133] Non-destructive examination of short segments could reduce costs in Phase 1A and Phase 2.

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[129] Ex. SCG-04, p. 59 (Applicants/Schneider).

[130] Ex. SCG-04, p. 60 (Applicants/Schneider).

[131] Tr. 436 (Applicants/Schneider).

[132] Applicants Opening Brief, p. 153.

[133] Applicants Opening Brief, pp. 151-153.

The Applicants also support witness Schneider's fourth alternative,[134] using TFI as an alternative to pressure tests or replacements in Phase 2 if the Applicants can validate TFI in Phase 1A as being equivalent to pressure testing to demonstrate long seam stability[135] and the Commission subsequently approves TFI as an alternative to pressure testing or replacing pipelines.[136] Witness Schneider noted: "Particularly for Phase 2 pipelines that are already piggable, this may present an alternative to greatly reduce the costs of achieving compliance with the Commission's directives in this Rulemaking."[137]

SCGC joins the Applicants in supporting witness Schneider's third and fourth alternatives.

VII. REVENUE REQUIREMENTS.

A. Proposed Revenue Requirements.

The Applicants explain in their Opening Brief that their estimated annual PSEP revenue requirements are derived from their forecasts of incremental capital costs and O&M costs.[138] In developing their proposed PSEP revenue requirements, the Applicants adjust the forecast of direct costs to include applicable overhead loaders and escalation.[139] However, as SCGC explained in its Opening Brief, the Applicants' forecasts of direct capital and O&M costs are highly inaccurate, include the cost of projects that will not occur, include projects that should not be ratepayer funded, and are badly out of date.[140] As a result, the Applicants' proposed annual PSEP revenue requirements should not be used to calculate the PSEP Surcharge.

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[134] Applicants Opening Brief, p. 107.

[135] Ex. SCG-04, p. 57.

[136] Ex. SCG-04, p. 46.

[137] *Ibid*.

[138] Applicants Opening Brief, p. 155.

[139] *Ibid*.

[140] SCGC Opening Brief, pp. 48-52.

B. Intervenor Proposals Relating to Revenue Requirements.

The Applicants note that SCGC witness Yap recommended that if the Commission approves the use of non-destructive examination as an alternative to pressure testing and replacing pipeline segments less than 1,000 feet in Phase 1A, given the small size of the projects, non-destructive examination costs should be entirely expensed.[141] The Applicants propose instead that they "be authorized to expense and capitalize NDE costs in accordance with our existing capitalization policies."[142]

During the hearing in this proceeding, Administrative Law Judge Long directed the Applicants to provide a copy of the Applicants' Capitalization Policies and to make the Capitalization Policies available as an exhibit in this proceeding.[143] Upon review of the Applicants' Capitalization Policies,[144] SCGC agrees that non-destructive examination costs should be treated in accordance with the Capitalization Policies.

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

A. PSEP Cost Recovery Accounts.

The Applicants propose to establish interest bearing PSEP cost recovery accounts ("PSEPCRAs") that "will be two-way balancing accounts that record the difference between the authorized revenue requirements collected by the utilities and the actual O&M and capital-related revenue requirements associated with implementation of the PSEP."[145] The Applicants also propose on the basis of some cross-examination of their witness Reyes that their two-way

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[141] Applicants Opening Brief, p. 160.

[142] *Ibid*.

[143] Tr. 1588; Ex. SCG-35.

[144] Ex. SCG-35 (Applicants)

[145] Applicants Opening Brief, p. 166.

balancing accounts have a cap.[146] Instead of having a cap on a two-way PSEPCRA, amounts that are debited for individual EAD-approved replacement projects should be capped, and the Applicants should not be permitted to use annual forecasted revenue requirements to calculate the PSEP Surcharge.

1. Amounts that are debited to the PSEPCRA for individual approved Phase 1A replacement projects should be capped.

The Applicants do not explain precisely how the proposed cap will operate, but it appears that they intend that the forecasted PSEP revenue requirements for a year will cap the amounts that can be debited to the Applicants' PSEPCRAs during a year for balancing against the revenues that are credited to the PSEPCRA during the year. However, the Applicants propose that they be permitted to "continue recording expenditures in excess of a cap for potential future recovery after Commission authorization…."[147]

The Applicants apparently propose the cap in their Opening Brief in order to make more palatable their combined proposals for a two-way PSEPCRA balancing account and for basing the PSEP Surcharge on a forecast of the PSEP revenue requirement for the year in which the PSEP Surcharge will be billed. However, the Applicants' proposed cap fails to make the Applicants' proposal to base PSEP Surcharges on forecasted annual PSEP revenue requirements more palatable. The Applicants' proposal for a cap should be rejected along with their proposal to base the PSEP Surcharge on forecasted annual PSEP revenue requirements.

As discussed in SCGC's Opening Brief, the Applicants' proposed forecasts of annual revenue requirements are based on highly inaccurate and out-dated estimates of direct costs.[148] The Applicants' proposal to base the PSEP Surcharge on a forecast would turn ratepayers into

[146] Applicants Opening Brief, pp. 166-167; Tr. 1495-1498 (Applicants/Reyes).

[147] Applicants Opening Brief, p. 167.

[148] SCGC Opening Brief, pp. 49-51.

being a bank to provide the Applicants with interest free short-term loans.[149] Lastly, the Applicants' proposal to calculate the PSEP surcharge on a forecasted revenue requirement is unsupported by any of the precedents cited by the Applicants.[150] Thus, the Applicants' proposal to base the PSEP Surcharge on a forecast of the PSEP revenue requirement for the year in which the PSEP Surcharge will be collected should be rejected.

If the use of the forecasts of PSEP revenue requirements is rejected, there is no basis for the proposed caps. The Applicants should be subject to caps, but the caps should be on the amounts that may be debited to the PSEPCRA for individual replacement projects that are approved in EAD proceedings. As long as the Applicants' recorded replacement cost for an individual project does not exceed the cost cap established in the EAD proceeding for the project, the revenue requirement associated with the capital investment in the pipeline investment should be permitted to be debited in the PSEPCRA.[151]

2. The PSEPCRA should include separate subaccounts for O&M expense and capital-related costs.

The Applicants contend that they should not be required to maintain subaccounts in the PSEPCRA which segregate expensed O&M from capital-related costs. They say that their "financial systems already distinguished between O&M and capital expenditures so that we can properly capture these costs within the accounts…."[152]

The Applicants miss the point. There is an asymmetry of information between the Applicants and intervenors. The Applicants have all the information, and the intervenors have none besides what is made available to them by the Applicants. Having the subaccounts would

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[149] SCGC Opening Brief, pp. 59-60.

[150] SCGC Opening Brief, pp. 60-62.

[151] SCGC Opening Brief, p. 31.

[152] Applicants Opening Brief, p. 167.

facilitate intervenor monitoring of the costs associated with each type of activity.[153] The Applicants attempt to avoid maintaining subaccounts within the PSEPCRA is nothing more than an attempt to withhold readily usable information from intervenors.

B. Rate Recovery of Authorized Phase 1A Costs.

The Applicants propose to bill PSEP Surcharges to recover the PSEP revenue requirement that they forecast for the year during which the Surcharge would be billed plus an amount to amortize the balance accumulated in the PSEPCRA during the previous year.[154]

1. The Applicants should not be permitted to calculate the PSEP Surcharge to recover PSEP revenue requirements forecasted for the year in which the surcharges will be billed.

As discussed in SCGC's Opening Brief,[155] the Applicants should not be permitted to calculate PSEP Surcharges to recover Phase 1 PSEP revenue requirements that are forecasted for the year in which the surcharges will be billed. Forecasts of revenue requirements are based on forecasts of direct costs that are classified as, at best, "between 4 and 5."[156] Thus, the forecasts of revenue requirements are based upon estimates of direct costs that are so inaccurate that the forecasts of revenue requirements cannot be used for ratemaking.

The Applicants say that upon approval of the PSEP, they will file advice letters to include updated revenue requirements to reflect Commission-ordered changes to the PSEP and to take into account the timing of approval of the PSEP.[157] However, that does not provide any assurance that the quality of the forecasts that are the basis for the proposed revenue requirements would be at all improved. For the reasons set forth in SCGC's Opening Brief, the

[153] Ex. SCGC-1, pp. 30-31 (SCGC/Yap).

[154] Applicants Opening Brief, p. 168.

[155] SCGC Opening Brief, pp. 63-65.

[156] Ex. SCG-21, p. 2 (Applicants/Buczkowski); Tr. 881 (Applicants/Buczkowski).

[157] Applicants Opening Brief, p. 168.

proposal to base PSEP Surcharges on forecasts of revenue requirements for the year in which the PSEP Surcharges are to be billed should be rejected.[158]

2. The Commission should not allow recovery of the revenue requirement associated with a replacement project until the project is used and useful.

The Applicants contend that they should be permitted to recover the forecasted revenue requirement associated with a replacement project before the project is used and useful.[159] This contention appears to be tied to the Applicants' proposal to use their PSEP Surcharges to recover revenue requirements that are forecasted for the year in which the surcharges will be billed. For the reasons given in SCGC's Opening Brief, capital-related costs associated with a PSEP replacement project should be permitted to be debited to the PSEPCRA only after the project becomes used and useful, with Allowance for Funds Used During Construction ("AFUDC") being accrued until the project becomes used and useful.[160]

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

The Applicants propose that they be permitted to start recovering costs that they have recorded in their Pipeline Safety and Reliability Memorandum Accounts ("PSRMAs").[161] They propose to accomplish recovery of PSRMA balances by transferring costs recorded in the PSRMAs to their new PSEPCRAs. Presumably, they would add the unrecovered PSRMA balances to the forecasted annual PSEP revenue requirements that the Applicants' propose to recover through the proposed PSEP Surcharge.

Before commencing recovery of costs debited to the Applicants' PSRMAs, there must be an opportunity for the Commission to consider whether the recorded costs are reasonable so that

[158] SCGC Opening Brief, pp. 63-65.

[159] Applicants Opening Brief, p. 169.

[160] SCGC Opening Brief, p. 54.

[161] Applicants Opening Brief, p. 169.

they can legitimately be recovered from ratepayers. The Commission stated in D.12-04-021: "The Commission will consider whether such properly recorded costs are reasonable and incremental as well as which costs, if any, may be recovered from ratepayers in revenue requirement at a later time in the Triennial Cost Allocation Proceeding."[162]

The Applicants have failed to make any showing whatsoever to demonstrate the reasonableness of the costs recorded in their PSRMAs. They claim that "particular projects and related costs are spelled out in detail in the Utility's January 13, 2012, comments."[163] However, Attachment A to the Applicants' January 13, 2012 comments in R.11-02-019 only contain a listing of pipelines, a column indicating "PSEP Filing Priority," a capital cost estimate, an O&M estimate, and a note about how much the Applicants expect would be done on the pipeline during the first year of the PSEP.[164] At best, the Applicants' estimates are "between 4 and 5."[165] Thus, no reliance can be placed upon the estimates shown in Attachment A to the Applicants' January 13, 2012, comments in determining whether the costs recorded in the Applicants PSRMAs are "reasonable and incremental."

Furthermore, it is unknown how much work has actually been accomplished on the projects identified in Attachment A to the Applicants' January 13, 2012, comments. The Applicants' witness Buczkowski testified that the Applicants waited until their PSRMAs became effective to commence the initial twelve-month period of the PSEP. As a result, the initial twelve months was a "floating twelve month period" which would commence only when the

[162] D.12-04-021, p. 7 (April 19, 2012).

[163] Applicants Opening Brief, p. 70.

[164] Ex. SCGC-3, Comment of SoCalGas and SDG&E in Response to Assigned Commissioner's Rulings and Supplement to Request for Memorandum Account, Attachment A (January 13, 2012).

[165] Tr. 881 (Applicants/Buczkowski).

advice letters proposing the Applicants' PSRMAs were approved.[166] Given that the PSRMAs became effective on May 20, 2012, the twelve-month period will extend to May, 2013.[167] At the time of the hearing in this proceeding in August, 2012, SoCalGas had recorded no capital costs in its PSRMA and only approximately $10.5 million in O&M expenses.[168]

The Applicants have clearly not sustained their burden of proof to show with a preponderance of the evidence that the costs recorded in the PSRMAs are reasonable and incremental so the costs may be recovered through the Applicants' PSEP Surcharges.

If the Applicants bear their burden to show that the costs recorded in their PSRMAs are reasonable and incremental, then it would be appropriate to transfer the PSRMA balances to the Applicants' PSEPCRAs for recovery of the balances through the Applicants' PSEP Surcharges. As discussed in SCGC's Opening Brief, the balances accumulated in the Applicants' PSRMAs would then effectively become the "year one" revenue requirement that would provide a basis for calculating the Applicants' "year one" PSEP.[169]

The accumulated PSRMA balances, as transferred to the Applicants' PSEPCRAs, should be all that is recovered through the "year one" PSEP Surcharges. As discussed above and in SCGC's Opening Brief, the Applicants should not be permitted to recover forecasted annual PSEP revenue requirements through the PSEP Surcharges.[170]

[166] Tr. 889 (Applicants/Buczkowski).

[167] *Ibid*; Tr. 892 (Applicants/Buczkowski).

[168] Tr. 1546 (Applicants/Reyes).

[169] SCGC Opening Brief, p. 66.

[170] SCGC Opening Brief, pp. 58-62, 63-65.

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

The Applicants' proposal to file expedited advice letters to adjust the forecasted annual levels of PSEP funding should be rejected. As discussed in SCGC's Opening Brief,[171] there should be no need to adjust approved forecasted annual PSEP revenue requirements because there should be no approved forecasted annual PSEP revenue requirements.

Furthermore, even if there were approved forecasts of annual PSEP revenue requirements, the Applicants' expedited advice letter process would effectively deny stakeholders any meaningful opportunity to scrutinize the proposed adjustments insofar as stakeholders would have only ten days rather than the usual twenty days to protest the advice letters.

E. Annual PSEP Update Report.

The Applicants propose to submit an "annual PSEP status report" to the Commission on or before March 31 of each year.[172] The Applicants say that "these annual reports will provide transparency regarding our ongoing PSEP work…."[173] The Applicants say they will make the report available to "interested parties," but they do not say how that will happen.

As proposed in SCGC's Opening Brief, the annual reports should be submitted by an advice letter to assure broad circulation to interested parties and to provide an opportunity for interested parties to provide comments on the reports.[174]

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[171] SCGC Opening Brief, pp. 66-67.

[172] Applicants Opening Brief, p. 172.

[173] *Ibid*.

[174] SCGC Opening Brief, pp. 67-68.

IX. ADDITIONAL INTERVENOR PROPOSALS.

A. Proposed Notice Requirement.

B. Local Transmission Interruption Credit Proposal.

C. BTS Reservation Charge Credit Proposal.

In its opening testimony, SCIP recommended that the Commission direct the Applicants to provide a credit toward BTS reservation charges for any period during which customers have their BTS service disrupted by PSEP work.[175] SCIP further recommended that the cost of BTS reservation credits should be funded 50 percent by Sempra shareholders and 50 percent by ratepayers with the ratepayers' share being recovered from noncore customers through the Noncore Fixed Cost Balancing Account ("NFCA").[176]

SCGC did not take a position on whether SCIP's proposal for a BTS reservation charge credit should be adopted, but SCGC urged the Commission to reject SCIP's proposal to make shareholders responsible for 50 percent of the costs of the credits and to reject SCIP's proposal to recover 50 percent of the credits from noncore customers through the NFCA.[177] If there were to be BTS reservation charge credits, the full cost should be borne by BTS customers by recording the cost of the credits in the Backbone Transmission Balancing Account ("BTBA").[178]

In its Opening Brief, SCIP withdraws its proposal for shareholders to fund 50 percent of SCIP's proposed BTS reservation charge credit.[179] SCIP is silent, however, on how the cost of the credit should be recovered from customers. SCIP does not advocate recovering the cost of the credit from noncore customers through the NFCA, but SCIP does not endorse recovery of the

[175] Ex. SCIP-1, p. 23 (SCIP/Beach).

[176] *Ibid*, pp. 23-24, (Footnote 29) (SCIP/Beach).

[177] SCGC Opening Brief, pp. 69-70.

[178] *Ibid*, p. 71.

[179] SCIP Opening Brief, p. 47.

cost of earned credit through the BTBA. For the reasons set forth in SCGC's Opening Brief, if the Commission decides to adopt SCIP's proposed BTS reservation charge credit for BTS service interruption caused by PSEP activities, the costs of the credit should be recovered through the BTBA.[180]

D. UWUA O&M Proposals.

E. Treatment of Robotic Royalties.

X. PHASE 1B.

Phase 1B includes "pipeline segments that would otherwise be addressed in Phase 1A, but which cannot be addressed in the near-term due to the need to construct new infrastructure to maintain service during pressure testing."[181] Currently, the only Category 4 pipeline that is assigned to Phase 1B insofar it "cannot be addressed in the near-term due to the need to construct new infrastructure" is Line 1600 in the SDG&E service territory.[182]

A. Line 1600.

The Applicants propose to construct a replacement line for Line 1600 in Phase 1B to enable them to pressure test the existing 16 inch Line 1600.[183] They say they are not seeking approval of Phase 1B costs at this time, but they admit that their forecast of replacement costs for Phase 1A includes costs to "pre-engineer" the replacement line for Line 1600.[184] The replacement pipeline would be an entirely new 36-inch pipeline that would have a direct cost of

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[180] SCGC Opening Brief, p. 71.

[181] Ex. SCG-4, p. 60 (Applicants/Schneider).

[182] Tr. 450 (Applicants/Schneider).

[183] Applicants Opening Brief, p. 191.

[184] Applicants Opening Brief, p. 190.

approximately $325 million.[185] The "pre-engineering cost" that the Applicants seek to recover in Phase 1A is $14.3 million, about 4 percent of the cost of the replacement pipeline.[186]

As SCGC explained in their Opening Brief,[187] Applicants should not incur the "pre-engineering" costs for Line 1600 in Phase 1A. The Applicants are currently making Line 1600 piggable as part of their Transmission Integrity Management Plan ("TIMP") activities.[188] A piggable Line 1600 would be able to accept TFI technology to validate the long seam stability of Line 1600.

The Applicants are proposing to use the TFI technology prior to pressure testing pipelines in Phase 1A. If the TFI technology is validated in Phase 1A as an alternative to pressure testing, the Applicants plan to propose that the Commission should approve TFI as an alternative to pressure testing or replacing pipelines.[189] If approval were obtained, Line 1600 could be inspected with TFI at the comparably small expense of about $200,000 per run while the line remains in service.[190] The need for replacing Line 1600 with a $325 million 36-inch pipeline would be avoided, and the cost of pressure testing Line 1600 would be avoided as well.

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 "pre-engineering" costs should be incurred for Line 1600 in Phase 1A.

Additionally, it is inappropriate to incur $143 million in "pre-engineering" costs in Phase 1A insofar as the Applicants' proposal to construct a new 36-inch diameter pipeline appears to

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[185] Technical Report of CPSD regarding the SoCalGas and SDG&E Pipeline Safety Enhancement Plan, R.11-02-019, p. 12 (January 17, 2012).

[186] Ex. SCGC-4, WP-IX-1-34.

[187] SCGC Opening Brief, p. 72.

[188] Ex. SCGC-1, Att. S, SoCalGas/SDG&E Response to DRA-DAO-24-02.

[189] Ex. SGC-04, pp. 51-57 (Applicants/Schneider).

[190] Applicants Opening Brief, p. 108.

be a project that is aimed at increasing capacity rather than addressing the type of safety improvements ordered by D.11-06-017.[191] A 36-inch pipeline has five times the delivery volume of a 16-inch pipeline.[192] Such a dramatic expansion of Applicants' transmission capability in San Diego County seems particularly inappropriate at a time when California is implementing the AB 32 cap-and-trade program to reduce greenhouse gas emissions in California to 1990 levels by 2020 with an ultimate target of reducing greenhouse gas emissions by 80 percent by 2050. Attaining California's greenhouse gas emission reduction goals will reduce consumption of natural gas dramatically during the useful life of the new 36-inch pipeline, negating the need for the pipeline.

XI. PHASE II.

The Applicants state that in Phase II they will "address all remaining transmission pipeline segments that do not have sufficient documentation to validate post-construction pressure tests to 1.25 times the pipeline's MAOP (i.e., Category 3 and 4 pipelines located in less populated areas that have not yet been addressed) and all other remaining transmission pipelines that have not been strength tested to modern standards."[193]

The Applicants' reference to Category 3 pipelines is correct, but the reference to Category 4 pipelines is incorrect. The Applicants' Category 3 includes pipelines in Class 3 and Class 4 areas and Class 1 and Class 2 High Consequence Areas that have documentation of in-service testing that is sufficient to show that they had operated continuously at a pressure of at

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[191] DPSD Report, p. 13.

[192] SCGC-1, p. 20 (SCGC/Yap).

[193] Applicants Opening Brief, p. 66.

least 1.25 times MAOP.[194] Insofar as D.11-06-017 does not allow for an "in-service" gas pressure test, the Applicants include Category 3 pipelines in Phase 2.[195]

However, Category 4 pipelines are those pipelines in Class 3 and 4 areas and Class 1 and 2 High Consequence Areas that do not have sufficient documentation of any pressure test--a hydrostatic pressure test, a pressure test using a medium other than water, or an in-service pressure test--to at least 1.25 times MAOP.[196] All Category 4 pipelines will be either pressure tested or replaced during Phase 1. They should not be identified as being addressed in Phase 2.

XII. CONCLUSION.

For the reasons set forth above and in SCGC's Opening Brief, SCGC respectfully requests that the Commission adopt the recommendations as set forth in the Summary of Recommendations that precedes this reply brief.

Respectfully submitted,

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[194] Ex. SCG-18, p. 12, footnote 16 (Applicants/Schneider).

[195] *Ibid*.

[196] Ex. SCG-18, p. 12 (Applicants/Schneider).