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

318175

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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

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[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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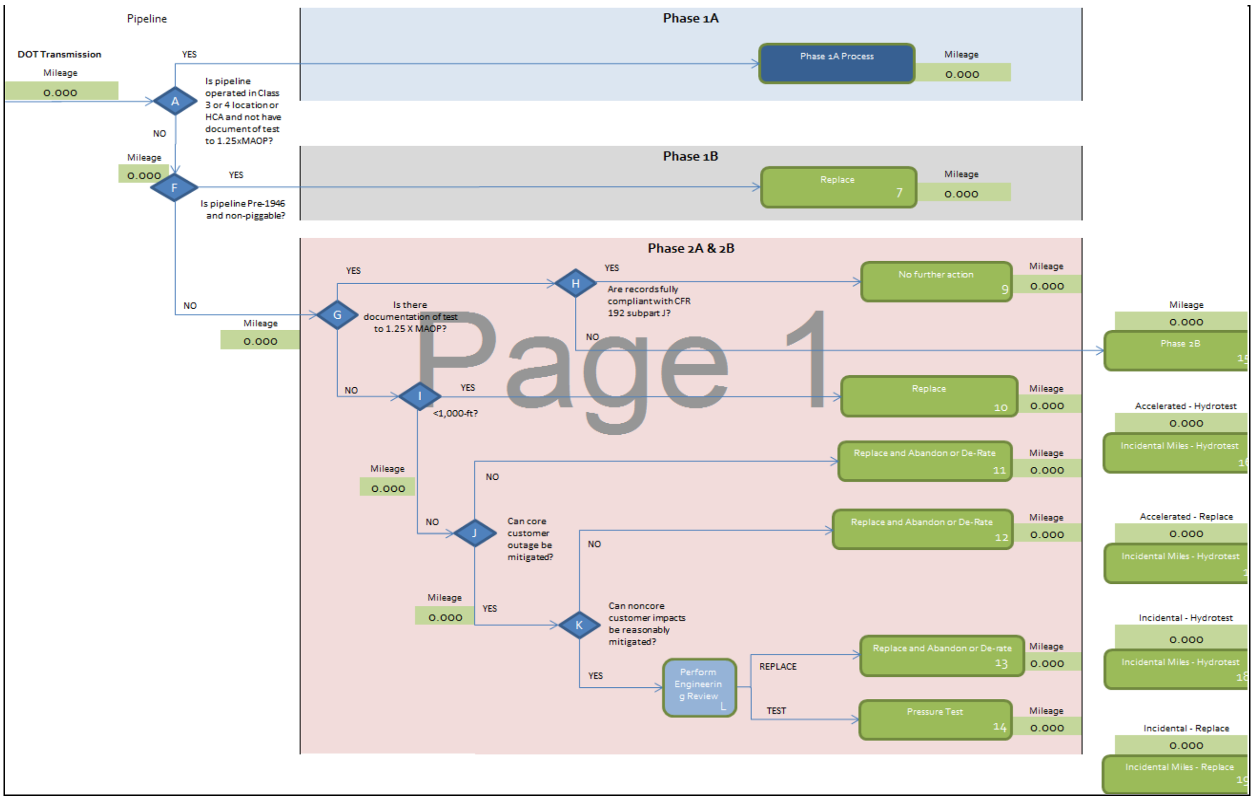
[23] As part of a seven stage review process, SoCalGas carefully reviews pipeline records and operational needs before initiating construction activity on a pipeline project. Through this process, SoCalGas anticipates some portion of remaining Phase 2A miles may be descoped from PSEP through the identification 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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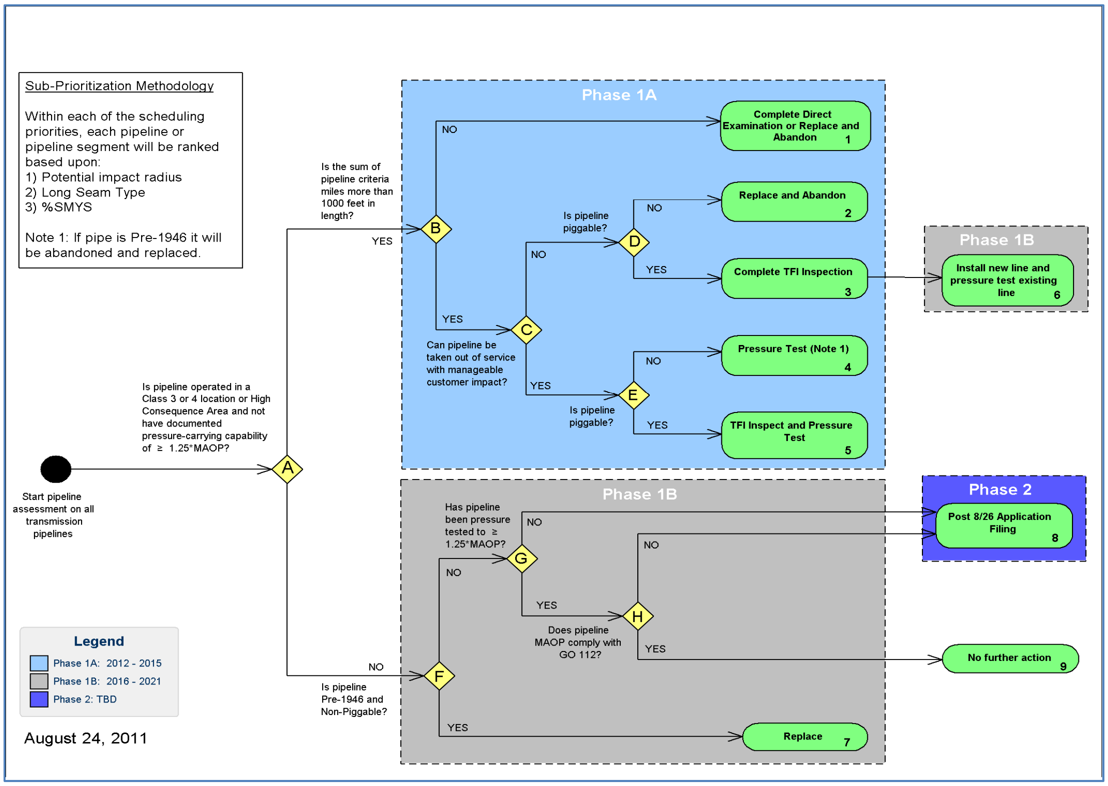
[25] D.14-06-007 at 59 (Ordering Paragraph 1).

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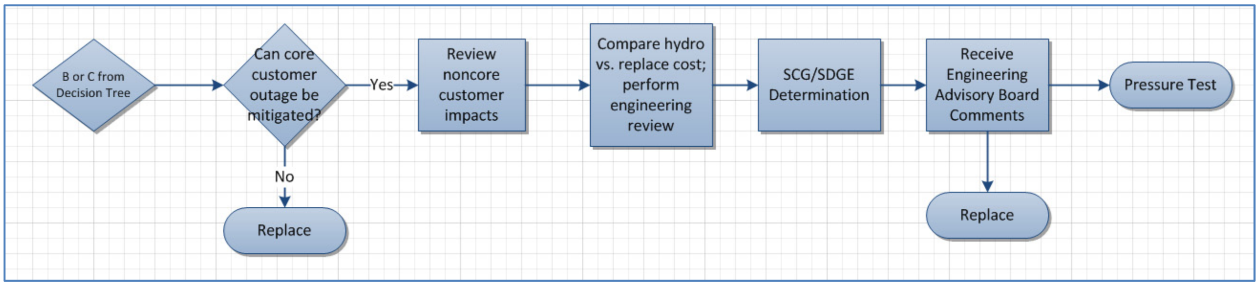
[26] As presented in A.11-11-002 (Rebuttal Testimony of Rick Phillips) at 8.
[27] *Supra* note 10.
[28] In rebuttal testimony (and as seen in the Replacement Decision Tree), SoCalGas and SDG&E proposed the formation of an Engineering Advisory Board to provide an extra level of comfort that SoCalGas and

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,

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

[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-

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[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;

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[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.

[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

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[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.

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[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

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[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.

[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-

[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.