Application No: A.18-11-010
Exhibit No:
Witness: R. Phillips

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for Review of Costs Incurred in Executing Pipeline Safety Enhancement Plan	Application A.18-11-010

CHAPTER III

AMENDED DIRECT TESTIMONY OF RICK PHILLIPS

(PIPELINE PROJECTS AND OTHER COSTS)

ON BEHALF OF

SOUTHERN CALIFORNIA GAS COMPANY

AND

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

November 13, 2018
(Amended October 21, 2019)

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I. PURPOSE AND OVERVIEW OF TESTIMONY

The purpose of my testimony is to demonstrate Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company's (SDG&E) prudent execution of the 44 Pipeline Safety Enhancement Plan (PSEP) pipeline projects presented in this Application and the reasonableness of the $716.6 million in capital expenditures and $76.6 million in operations and maintenance (O&M) expenditures incurred in executing the projects presented for review and rate recovery in this testimony; and the reasonableness of $8.5 million in expenditures for other costs incurred to execute PSEP. As part of this demonstration, as authorized by Decision (D.) 14-06-007, I will explain the project cost components, application of the Commission-approved Decision Tree for PSEP pipeline projects, the calculation of disallowed project costs, and provide a reconciliation of the "as filed" mileage as compared to the actual mileage.

The costs in this chapter provide the basis for determining the revenue requirements recorded in SoCalGas and SDG&E's Safety Enhancement Capital Cost Balancing Accounts (SECCBAs) and Safety Enhancement Expense Balancing Accounts (SEEBAs) and Pipeline Safety and Reliability Memorandum Accounts (PSRMAs). As demonstrated in my testimony and workpapers, these PSEP costs were reasonably incurred and the associated revenue requirements are justified for rate recovery.

To facilitate the review process and ease of reference, detailed information for each project is included in the supporting project workpapers, which are voluminous and available upon request. The information contained in this chapter is designed to provide a summary of the projects and associated costs.

II. PROJECT COST COMPONENTS

The costs presented in this chapter are those incurred through April 2018. Accounting adjustments made between May 2018 and the date of this Application are addressed in Chapter IX (Reyes). The project costs included in this chapter include costs incurred in direct support of individual hydrotest, replacement, or abandonment projects; project support costs not directly tied to a specific project, and incurred to support overall implementation of PSEP;[1] and indirect costs.[2] Project costs may include both capital and O&M expenditures, depending on the specifics of the project. For example, the majority of work associated with pressure testing is considered O&M. As part of the normal pressure testing process, however, a section of the existing pipeline is removed to accommodate the temporary test heads that are used to conduct the pressure test. After the line is tested and the temporary test heads are removed, a new section of pipe is installed to "tie-in" the just-tested segment to the pipeline on either end of the segment. The tie-in pipe is new pipe and is capitalized in accordance with SoCalGas and SDG&E's accounting policy. Similarly, replacement projects are typically treated as capital; however there can be O&M costs associated with a replacement or abandonment project executed on a distribution line, if the segment that is replaced is 40 feet or less in length.[3]

[1] PSEP organizational costs not attributable to a specific project (i.e., PSEP General Management and Administration costs) are allocated to hydrotest, replacement, abandonment, and valve projects as discussed in Chapters V (Mejia) and VI (Tran).

[2] Certain company overhead costs are deemed incremental to PSEP and subject to recovery as they are associated with incremental PSEP activities. The applicable incremental overheads are included in the costs presented for review in this Application, as further discussed in Chapter VII (Moersen).

[3] This is in accordance with SoCalGas and SDG&E's accounting policy.

III. SUMMARY OF PROJECT COSTS[4]

A. Replacement Projects

Table 1 – Replacement Projects
Summary of Capital and O&M Costs (in $000s)

Project	Company	Capital		O&M		Total	
30-18 Sections 1 and 3	SCG	$	28,281		-	$	28,281
33-120 Section 3	SCG	$	7,320	$	120	$	7,440
36-1002	SCG	$	2,035	$	0	$	2,035
36-9-09 North Section 1	SCG	$	53,835	$	2	$	53,837
36-9-09 North Section 3	SCG	$	27,244	$	4	$	27,248
36-9-09 North Section 4A and 4B	SCG	$	15,145		-	$	15,145
36-9-09 North Section 7A and 7B	SCG	$	37,729	$	15	$	37,744
37-07	SCG	$	31,283	$	5	$	31,288
37-18 Sections 1,2,3,4,5	SCG	$	58,054		-	$	58,054
38-200	SCG	$	8,539	$	23	$	8,562
38-501	SCG	$	22,339	$	7	$	22,346
38-504	SCG	$	5,714	$	7	$	5,721
38-512 Sections 1, 2, 3	SCG	$	30,889	$	1,245[5]	$	32,134
38-514	SCG	$	14,751	$	23	$	14,774
38-931	SCG	$	7,467		-	$	7,467
41-17	SCG	$	2,744	$	0	$	2,744
41-116	SCG	$	227		-	$	227
41-6000-2[6]	SCG	$	84,857		-	$	84,857
43-121 North Section 1	SCG	$	15,991		-	$	15,991
43-121 South	SCG	$	35,844		-	$	35,844
44-137	SCG	$	27,605	$	16	$	27,621
44-687	SCG	$	5,892	$	10	$	5,902
44-720	SCG	$	10,981	$	9	$	10,990
49-28	SDG&E	$	46,990		-	$	46,990
49-15	SDG&E	$	43,489	$	0	$	43,489
85 South Newhall	SCG	$	9,880		-	$	9,880
2000-West Santa Fe Springs Station	SCG	$	9,416		-	$	9,416
Total		**$**	**644,541**	**$**	**1,486**	**$**	**646,027**

[4] Note that "-" indicates a zero value, whereas "0" indicates a value less than $500 that is rounded down to zero.
[5] Supply Line 38-512 O&M costs reflect the costs incurred for a short 20-foot segment of pipe. The proper accounting treatment for replacement costs for distribution pipe that is less than 40 feet is to record the cost as O&M. *See* the supporting workpaper narrative for the Supply Line 38-512 project for additional information.
[6] This project is identified as 6914 Installation in the Monthly PSEP Status Report submitted to the CPUC.

B. Pressure Test Projects

Table 2 – Pressure Test Projects
Summary of Capital and O&M Costs (in $000s)

Project	Company	Capital	O&M	Total
31-09	SCG	-	$ 3,651	$ 3,651
32-21 Section 1	SCG	$ 1,083	$ 9,289	$ 10,372
32-21 Section 2	SCG	$ 761	$ 4,740	$ 5,501
32-21 Section 3	SCG	$ 683	$ 3,175	$ 3,858
37-18-F	SCG	$ 83	$ 7,473	$ 7,556
49-11	SDG&E	$ 4,762	$ 2,613	$ 7,375
406 Section 3	SCG	$ 390	$ 2,222	$ 2,612
2000-C	SCG	$ 3,086	$ 10,867	$ 13,953
2001 West-B	SCG	$ 686	$ 4,430	$ 5,116
2003 Section 2	SCG	$ 488	$ 2,439	$ 2,927
Total		**$ 12,022**	**$ 50,899**	**$ 62,921**

C. Combination Replacement and Pressure Tests Projects

Table 3 – Combination of Replacement and Pressure Test Projects
Summary of Capital and O&M Costs (in $000s)

Project	Company	Capital	O&M	Total
36-9-09 North Section 5A	SCG	$ 14,197	$ 2	$ 14,199
49-13	SDG&E	$ 19,010	$ 4,569	$ 23,579
404 Sections 1, 2, 2A, 3, 3A, 4&5, 8A, and 9	SCG	$ 13,848	$ 12,484	$ 26,332
1004	SCG	$ 6,899	$ 7,121	$ 14,020
Total		**$ 53,954**	**$ 24,176**	**$ 78,130**

D. Abandonment Projects

Table 4 – Abandonment Projects
Summary of Capital and O&M Costs (in $000s)

Project	Company	Capital	O&M	Total
36-9-09 South	SCG	$ 2,339	$ 2	$ 2,341
36-9-09 JJ	SCG	$ 1,905	$ 2	$ 1,907
Kern Wildlife Bundle	SCG	$ 1,888	$ 4	$ 1,892
Total		**$ 6,132**	**$ 8**	**$ 6,140**

IV. MISCELLANEOUS COSTS

SoCalGas and SDG&E have also incurred various miscellaneous costs that were necessary to execute PSEP. Table 5 includes a summary of these costs:

Table 5 – Miscellaneous Costs
Summary of SoCalGas and SDG&E Costs (in $000s)

Cost Type	SoCalGas	SDG&E	Total
Facilities Lease Expense	$ 6,112	$ 363	$ 6,475
Descoped Projects	$ 746	-	$ 746
Post-Completion Adjustments	$ 1,404	$ (115)	$ 1,289
Total	**$ 8,262**	**$ 248**	**$ 8,510**

A. Facilities Lease Costs

The costs included in Facilities Lease Expense consist of: (1) lease expense associated with the 22nd and 23rd floors at the Gas Company Tower in Los Angeles, (2) a portion of classroom space[7] leased by SoCalGas and SDG&E to conduct training of PSEP field personnel, and (3) the lease of office space[8] to house SDG&E PSEP personnel.

As described in Chapter II (Phillips), because PSEP is a large incremental project and there were insufficient company personnel available to undertake such a program, SoCalGas and SDG&E retained additional internal and external personnel and leased two additional floors at the Gas Company Tower to house the personnel to manage PSEP. In addition, SoCalGas and SDG&E leased office space in the San Diego area to house a smaller group of PSEP employees working on projects in the SDG&E service territory. As the amount of personnel required to execute the SDG&E PSEP projects began to diminish, the additional office space was no longer needed and the lease for the San Diego office terminated on December 31, 2016. The remaining SDG&E PSEP personnel have moved into other offices at SDG&E's existing facilities.

[7] The lease for classroom space terminated on December 31, 2015.
[8] The lease for San Diego office space terminated on December 31, 2016.

B. Descoped Projects

During the course of Phase 1A, planning work began on a number of projects that were later descoped or cancelled through either scope validation activities or the reduction of the Maximum Allowable Operating Pressure (MAOP) to a level sufficient to bring the line outside the scope of PSEP. SoCalGas and SDG&E seek recovery of $745,885 for the cost of descoped projects. The amount included for recovery is associated with pipelines installed prior to 1956.

Table 6 – Descoped Projects
Summary of Record Search Disallowance Costs (in $000s)

Project	Vintage	Total Cost	Records Search[9]	Net Total	Reason
2001 East	1946-1955	$ 14	-	$ 14	Scope validation
36-1006	1946-1955	$ 1	-	$ 1	Pipe operating below 20% SMYS
44-719	1946-1955	$ 1	-	$ 1	Pipe operating below 20% SMYS
MLV GT-NG 247	NA	$ 63	-	$ 63	Scope validation
Valve 115	NA	$ 157	-	$ 157	Scope validation
Valve Goleta	NA	$ 250	-	$ 250	Scope validation
Valve Los Alamitos	NA	$ 134	-	$ 134	Scope validation
Valve Lampson	NA	$ 18	-	$ 18	Scope validation
Valve Quigley Station	NA	$ 108	-	$ 108	Scope validation
Total		**$ 746**	**$ -**	**$ 746**	

C. Post-Completion Cost Adjustments

Post-completion cost adjustments in the amount of $1,289,471 associated with lines that were presented for review (including descoped projects) in A.16-09-005 are included for recovery in this Application. Post-completion adjustments occur when invoices or accounting adjustments are processed after the filing of an Application for an after-the-fact reasonableness review. Despite the best efforts of SoCalGas and SDG&E to capture all items during the close-out process, post-completion adjustments occur that may result in increased or decreased costs.

[9] D.14-06-007 at 39.

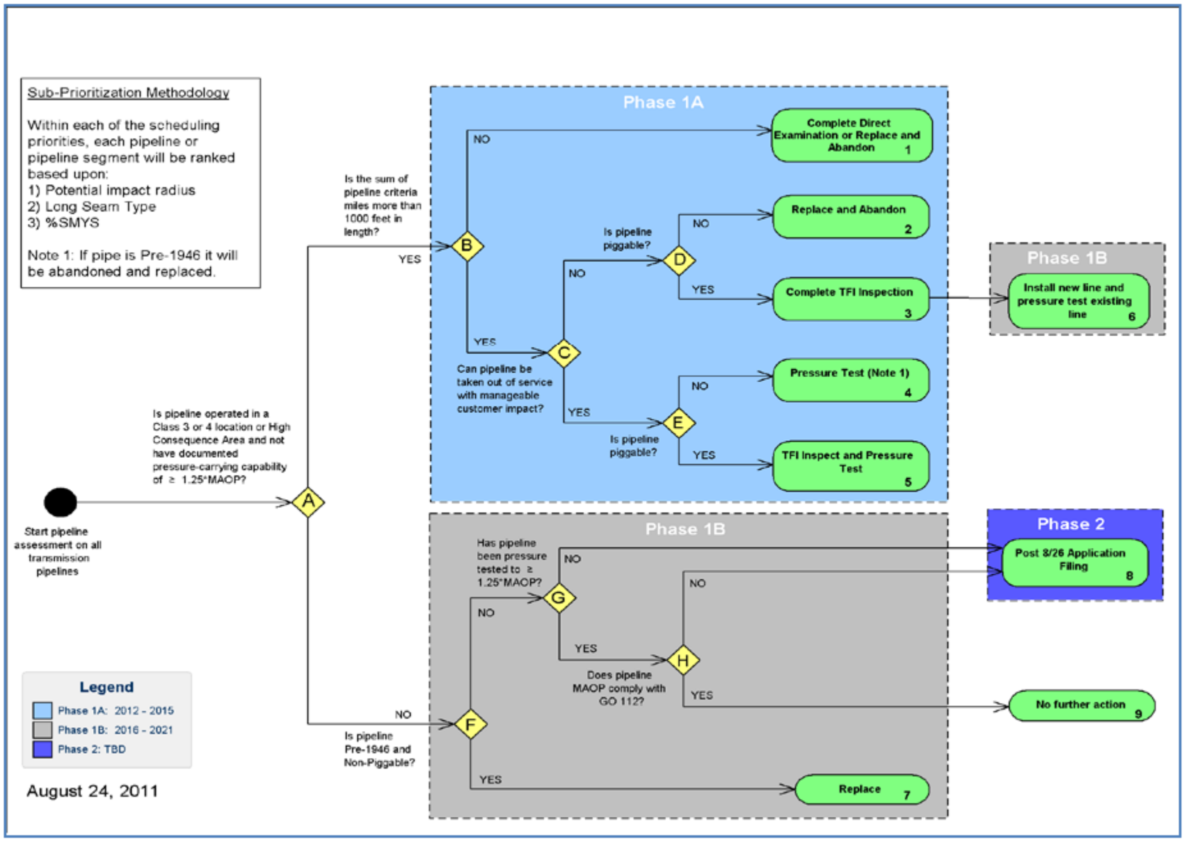
For the costs presented herein, the primary categories of post-completion adjustments are contractor invoices, accrual reversals, company labor, and journal entry adjustments.

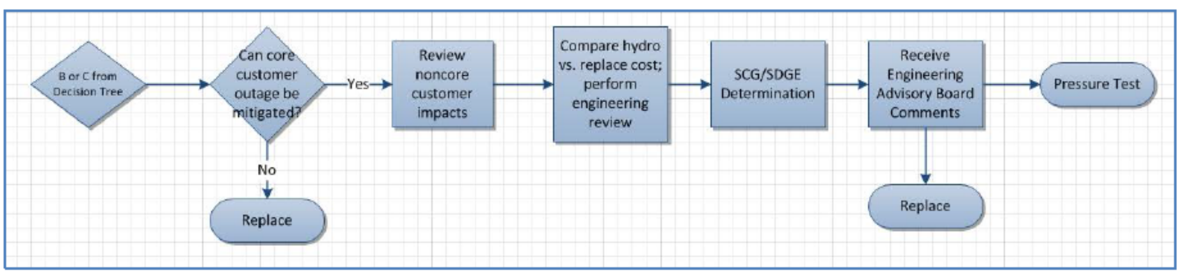
V. APPLICATION OF THE COMMISSION-APPROVED DECISION TREE FOR PSEP PIPELINE PROJECTS

In addressing pipelines set to be tested or replaced through SoCalGas and SDG&E's PSEP, a foundational decision is whether to pressure test or replace that pipeline segment.[10] SoCalGas and SDG&E's Commission-approved Decision Tree methodology guides the pressure test-versus-replace decision-making process and is illustrated below:

[10] When SoCalGas and SDG&E submitted their proposed PSEP (and Decision Tree) to the Commission for review and approval in 2011, SoCalGas and SDG&E proposed to conduct in-line inspections using transverse field inspection (TFI) technology prior to performing pressure tests to validate the effectiveness of TFI in identifying long seam flaws or anomalies in pipelines. The results of pressure testing were to be compared with the results of the TFI to determine whether TFI provides an equivalent alternative to pressure testing – potentially reducing Phase 2 PSEP costs by allowing Phase 2 pipelines that cannot be pressure tested with manageable customer impacts to be addressed using TFI rather than through replacement. The State subsequently enacted Public Utilities Code section 958(c)), which expressly requires pressure testing or replacement of pipelines thereby precluding SoCalGas and SDG&E from implementing equivalent assessment methods to validate long seam integrity. SoCalGas and SDG&E nevertheless conducted TFI assessments on some pipelines as an additional safety enhancement measure and to validate the effectiveness of the TFI technology. The costs for those TFI assessments are not included in this Application.

Figure 1: SoCalGas and SDG&E PSEP Decision Tree Matrix[11]





The Decision Tree depicts 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

[11] D.14-06-007 at 22, 59 (Ordering Paragraph 1) approved the Decision Tree proposed in SoCalGas and SDG&E's Amended Pipeline Safety Enhancement Plan A.11-11-002/R.11-02-019 at 19.

removed from service for pressure testing without significantly impacting customers. These pipeline categories are then further analyzed to determine other factors that may impact whether to pressure test or replace the segment. These steps are depicted in the Replacement Decision Tree.[12] The Replacement Decision Tree concepts were similarly adopted in D.14-06-007.[13]

The additional analysis is based on certain principles used to guide the test-versus-replace decision: (1) SoCalGas and SDG&E will not interrupt service to 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 hearings in A.11-11-002. It is important to note that there is no industry-wide standard that balances the risk of a pipeline failure with the cost of testing or replacing. Because of SoCalGas and SDG&E's engineering expertise and knowledge of the pipelines they operate, they are in the best position to make this determination on a project-by-project basis.

A. <u>Segments Less Than 1,000 Feet</u>

Generally, pipeline segments that are less than 1,000 feet in length are set to be replaced. As embodied in the Decision Tree, SoCalGas and SDG&E anticipate replacing and abandoning these short segments because, as described in the original 2011 PSEP application, it is usually

[12] As presented in A.11-11-002 (Rebuttal Testimony of Rick Phillips) at 8.
[13] D.14-06-007 at 2, 59 (Ordering Paragraph 1).

more cost effective to replace these short segments. SoCalGas and SDG&E may, however, engage in further review during the early planning stage to determine the most appropriate action, consistent with Commission and State mandates. Costs and other engineering and constructability factors are considered depending on the situation of each unique pipeline segment. An important additional consideration is that installing new pipe, manufactured to modern standards, further enhances the safety and reliability of the pipeline system.

B. Segments Greater Than 1,000 Feet

Per the Decision Tree, pipeline segments greater than 1,000 feet are further segregated based on whether the pipeline can be taken out of service. Pipeline segments that are greater than 1,000 feet in length that can be removed from service for pressure testing are generally pressure tested (unless the segment was installed prior to 1946 and is unpiggable, or other factors indicate replacement should occur). Pipeline segments that are greater than 1,000 feet in length that cannot be removed from service per the Decision Tree are replaced. Ultimately, the pressure test-or-replace decision is determined to achieve the PSEP objectives to enhance public safety, minimize customer and community impacts, and maximize the cost-effectiveness of safety investments for the benefit of customers.

VI. 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,"[14] and that address "all

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

natural gas transmission pipeline … even low priority segments,"[15] while also "[o]btaining the greatest amount of safety value, i.e., reducing safety risk, for ratepayer expenditures."[16] 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 would otherwise be addressed in a later phase of PSEP under the approved prioritization process, but are advanced to Phase 1A to realize operating and cost efficiencies. Accelerated miles may be Phase 1B or Phase 2. Phase 1B addresses pipelines installed before 1946 that are unpiggable. Phase 2A includes 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 (HCAs). Phase 2B segments are those segments that have records of a pressure test that do not meet all the requirements of modern pressure testing standards in 1970 (49 Code of Federal Regulations (CFR) Part 192, Subpart J).[17]

Addressing Phase 2B segments as accelerated mileage is consistent with the Commission's directive in D.11-06-017 that all California pipeline operators "must file and serve a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)."[18] The Commission issued this order after

[15] D.11-06-017 at 20.
[16] D.11-06-017 at 22.
[17] Current pressure test standards were developed and issued as part of Part 192, 49 CFR Subpart J – recognized as the modern standard for pressure testing. D.11-06-017 requires in-service natural gas transmission pipeline in California to have been pressure tested in accordance with modern standards for safety (*see* D.11-06-017 at 18). These requirements will require SoCalGas and SDG&E to locate records of pressure testing in accordance with Subpart J standards or conduct such pressure tests or replace the pipeline.
[18] D.11-06-017 at 29 (Conclusion of Law 4) and at 31 (Ordering Paragraph 4).

concluding 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-conscience implementation plan."[19] All Phase 2B accelerated mileage addressed in the projects presented in this proceeding were included for constructability and cost savings purposes.

Incidental miles are pipeline miles that do not fall within the scope of the Commission's directives in D.11-06-017 or California Public Utilities Code section 958, but are addressed as part of a PSEP project, where their inclusion is determined to improve cost and program efficiency, address constructability, or facilitate continuity of testing.[20] Both incidental and accelerated miles are included to minimize customer impacts, in response to operational constraints, or because of the cost and operational efficiencies gained by incorporating them into the project scope rather than circumventing them.[21]

VII. DISALLOWED COSTS

In D.14-06-007, the Commission approved SoCalGas and SDG&E's proposed PSEP, with some limited exceptions. D.14-06-007 (as modified by D.15-12-020) ordered that certain specified costs discussed below would be disallowed from recovery in rates. Table 7 summarizes the disallowed costs as relevant to the projects presented for review in this Application.

[19] *Id.* at 18.

[20] An additional benefit of addressing incidental mileage is to further confirm the integrity of the pipeline.

[21] Incidental and accelerated miles may be included in a pressure test or replacement project but are significantly more likely to be addressed in connection with a pressure test project because of the efficiencies realized by pressure testing longer segments of pipeline.

Table 7 – Disallowed Costs[22]
Summary of SoCalGas and SDG&E Costs (in $000s)

Disallowance Type	SoCalGas	SDG&E	Total
Post-1955 PSEP Costs[23]	$ 1,415	$ 491	$ 1,906
Undepreciated Book Balances[24]	$ 225	$ 1	$ 226
Executive Incentive Compensation[25], [26]	$ 1	0	$ 1
Records Search[27]	-	-	-
Total	**$ 1,641**	**$ 492**	**$ 2,133**

The post-1955 costs have been included in the total project costs for review but have not been included for recovery in rates. In other words, the costs presented for review for each project in this proceeding include the amount of the (post-55) disallowances calculated by Applicants but are excluded from the revenue requirement and rate calculations.

On a combined basis (i.e., in A.14-12-016, A.16-09-005, and this proceeding), SoCalGas and SDG&E have recognized PSEP disallowances totaling approximately $26.7 million to date.

A. Post-1955 Disallowed Costs

For the projects in this Application, SoCalGas and SDG&E have acknowledged disallowances totaling approximately $1.9 million. Table 8 below reflects the Post-1955 PSEP disallowances. The disallowance costs are not sought for recovery in rates and have not been included in Applicants' requests in this Application.

[22] The costs were removed from the utilities' applicable regulatory accounts in the balances presented in Chapter IX (Reyes).
[23] D.14-06-007 at 56-57 (Conclusions of Law 13 and 14); *see also* D.15-12-020 at 23 (Ordering Paragraph 1).
[24] D.14-06-007 at 57 (Conclusion of Law 15); *see also* D.15-12-020 at 24 (Conclusion of Law 10).
[25] D.14-06-007 at 38.
[26] SoCalGas and SDG&E included $4,422 of executive compensation for review and recovery in this Application. To comply with D.14-06-007, SoCalGas and SDG&E have acknowledged a disallowance of the Executive ICP component of $1,030. This figure rounds in Table 7 to $1 and "0", i.e., too negligible to be reflected in the table.
[27] D.14-06-007 at 39.

Table 8 – Disallowed Post-1955 PSEP Costs
Summary of SoCalGas and SDG&E Costs (in $000s)

Project	Capital	O&M	Total
2001 West-B Sections 17, 18, 19	-	$ 5	$ 5
2003 Section 2	-	$ 311	$ 311
31-09 Section 1	-	$ 821	$ 821
36-9-09 North Section 3	$ 265	-	$ 265
49-11 Section 1		$ 491	$ 491
404 Sections 2A, 4A, 4&5, 8A	$ 7	$ 3	$ 10
2000 West Santa Fe Springs	$ 3		$ 3
Total	**$ 275**	**$ 1,631**	**$ 1,906**

The project workpapers supporting this Application each provide project-specific disallowance calculations. Included below is a brief overview of how SoCalGas and SDG&E calculated the above disallowances.

i. Post-1955 Hydrotest Projects without Sufficient Record[28] of a Pressure Test

For the hydrotest projects presented in this Application, SoCalGas and SDG&E identified the pipeline mileage associated with post-1955 pipe without sufficient record of a pressure test. Based on this mileage, SoCalGas and SDG&E deducted a disallowance from total project costs in accordance with the Commission's directives. Where applicable, SoCalGas and SDG&E calculated the percentage of pipe that does not have sufficient record of a pressure test, and used this percentage to determine the portion of project costs subject to disallowance (i.e., the percent of length of disallowed pipe is the same percent used to calculate the cost disallowance). When incidental mileage is included to facilitate the constructability of post-1955 vintage pipeline hydrotest projects, SoCalGas and SDG&E include this mileage in calculating the disallowance.

[28] For the purpose of determining a disallowance, "sufficient" means record that provides the minimum information to demonstrate consistency with then applicable industry standards on strength testing and recordkeeping or compliance with then applicable regulatory strength testing and recordkeeping requirements.

When accelerated mileage is included in a post-1955 vintage pipeline hydrotest project, that mileage is included for review and cost recovery because it otherwise would be addressed at a later stage in PSEP and would be subject to cost recovery at that time.

ii. Post-1955 Replacement Projects without Sufficient Record of a Pressure Test

For the replacement projects presented in this Application, SoCalGas and SDG&E have identified the pipeline mileage associated with post-1955 mileage without sufficient record of a pressure test. Based on the mileage of post-1955 pipe without sufficient record of a pressure test, SoCalGas and SDG&E calculate a disallowance based on SoCalGas and SDG&E's average cost of pressure testing.[29] For the projects presented for review in this Application, SoCalGas and SDG&E calculated a system average pressure test cost of $2.1 million per mile[30] and multiplied that cost by the length of pipe subject to disallowance. The resulting amount is acknowledged as a disallowance. In this way, consistent with the Commission's directives, a disallowance is assessed, but customers bear the revenue requirement of the net replacement costs, as they "benefit from having a new safe and reliable pipeline."[31]

For replacement projects, SoCalGas and SDG&E do not include incidental and accelerated mileage in determining the capital disallowance. This is because the accelerated mileage would need to be addressed as part of a later phase of PSEP, and the incidental mileage has record of a pressure test and thus, is not subject to disallowance. Moreover, unlike the

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[29] D.14-06-007 at 34-35 ("Where replacement of the pipeline is planned rather than test existing pipelines, the system average cost of actual pressure testing should be an offset against the replacement costs of the pipelines for revenue requirement purposes."), 57 (Conclusion of Law 14); D.15-12-020 at 23 (Ordering Paragraph 1) ("where such pipeline segment is replaced rather than pressure tested, the utility must absorb an amount equal to the average cost of pressure testing a similar segment").

[30] As of April 30, 2018, when projects presented herein had completed financial closeout and recorded the majority of costs.

[31] D.14-06-007 at 36.

pressure test disallowance, SoCalGas and SDG&E absorb the undepreciated book value for replacement and abandonment projects. In other words, customers receive the benefit of a brand-new pipe, and the remaining book value of the replaced or abandoned pipe is absorbed by shareholders.

B. Undepreciated Book Value for Post-1955 Replacement or Abandonment Projects without Sufficient Record of a Pressure Test Costs

For replacement and abandonment projects without sufficient record of a pressure test and with remaining book value, SoCalGas and SDG&E acknowledge the reduction to rate base in an amount equal to the undepreciated book value of the entire replacement or abandonment project.

C. PSEP Executive Incentive Compensation Costs

SoCalGas and SDG&E do not seek to recover in rates any executive incentive compensation costs, in compliance with the Commission's directive in D.14-06-007. SoCalGas and SDG&E do not seek review or recovery of costs associated with executive incentive compensation in this proceeding.

D. Pressure Test Records Search Costs

SoCalGas and SDG&E tracked costs associated with their search for pressure test records. These record search costs were deducted as disallowances in SoCalGas and SDG&E's prior PSEP after-the-fact reasonableness reviews – A.14-12-016 and A.16-09-005. SoCalGas and SDG&E have not incurred records search costs since March 2016, the date through which costs were incurred and presented for review in A.16-09-005; thus, this Application does not include disallowances related to searching for pressure test records.

VIII. PSEP MILEAGE RECONCILIATION

As required by D.14-06-007, a reconciliation of the "as filed" mileage with the actual mileage that was pressure tested, replaced or abandoned is included in Tables 9 and 10 below for the projects presented in this Application.[32]

Table 9 – SoCalGas Pipeline Projects
Mileage Summary

Line	As Filed (Miles)	Included in this Filing (Miles)	Included in this Filing (Feet)
1004	19.70	9.032	47,685
2000 West Sec (1,2,3)[33]	117.60		
2000-C		7.585	40,047
2000-West Santa Fe Spring Sta.		0.200	1,054
2001 West[34]	64.1		
2001 West-B		1.800	9,505
2003[35]	26.5		
2003 Section 2		0.094	494
30-18[36]	2.58		
30-18 Section 1 and 3		2.011	10,619
31-09	12.81	0.212	1,120
32-21[37]	10.23		
32-21 Section 1		1.561	8,241
32-21 Section 2		1.602	8,459
32-21 Section 3		2.391	12,626
33-120[38]	1.25		
33-120 Section 3		0.516	2,725
36-1002	0.21	0.034	178

[32] The "as filed" mileage is consistent with that contained in the workpapers included with the SoCalGas and SDG&E Amended PSEP Application filed in December of 2011.
[33] Line 2000, because of its length and the unique characteristics of its non-contiguous sections, is being remediated and managed in phases: 2000-A, 2000-B, 2000-C, 2000-D, 2000-E and 2000-West.
[34] Line 2001-West, because of its length and the unique characteristics of its non-contiguous sections, is being remediated and managed in phases: 2001 West-A, 2001 West-B and 2001 West-C.
[35] Line 2003 was divided into four separate projects for planning and remediation due to location, permitting and constructability issues: Sections 1, 2, 3, and 4.
[36] Line 30-18 was divided into three projects for separate planning and execution, due to location, permitting and constructability issues: Sections 1, 2, and 3.
[37] Line 32-21 was divided into three projects for separate planning and execution, due to permitting and constructability issues: Sections 1, 2, and 3.
[38] Line 33-120 was divided into three projects for separate planning and execution, due to permitting and constructability issues: Sections 1, 2, and 3.

Line	As Filed (Miles)	Included in this Filing (Miles)	(Feet)
36-9-09 North[39]	16.02		
36-9-09 North Section 1		5.975	31,549
36-9-09 North Section 3		2.956	15,607
36-9-09 North Section 4A and 4B		1.034	5,461
36-9-09 North Section 5A		1.493	7,883
36-9-09 North Section 7A and 7B		4.260	22,492
36-9-09 South	NA	1.239	6,544
36-9-09 JJ	NA	0.461	2,434
37-07	2.68	3.222	17,010
37-18[40]	4.16		
37-18 Sections 1,2,3,4,5		4.291	22,658
37-18-F		2.084	11,002
38-200	0.23	0.369	1,950
38-501	1.98	2.442	12,889
38-504	NA	0.377	1,992
38-512	4.78		
38-512 Sections 1,2,3		4.960	26,191
38-514	NA	2.930	15,472
38-931	NA	2.406	12,702
38-KWB-P1B-01 (Kern Wildlife Bundle)	NA	15.225	80,389
404[41]	37.8		
404 Secs 1,2,2A,3,3A,4&5,8A, and 9		12.655	66,820
406	20.7		
406 Section 3		0.433	2,286
41-17	3.58	2.620	13,831
41-116	0.001	0.009	49
41-6000-2	39.95		
6914 Extension		11.741	61,993
43-121[42]	4.41		
43-121 North Section 1		1.009	5,325
43-121 South		1.477	7,799
44-137	1	1.039	5,486
44-687	0.23	0.303	1,600
44-720	1.17	1.493	7,884
85 South Newhall	NA	0.174	920
Total	**393.67**	**115.71**	**610,978**

[39] Line 36-9-09 North, because of its length and non-contiguous sections, was divided into 8 projects for separate planning and execution. Sections 4, 5 and 7 were further bifurcated due to permitting and constructability issues.
[40] Line 37-18 was divided into 3 projects for separate planning and execution, due to either location, permitting or constructability.
[41] Line 404, because of its length and non-contiguous sections, was divided into 9 projects for separate planning and execution, due to either location, permitting or constructability.
[42] Line 43-121 was divided into two separate projects for separate planning and execution, due to either location, permitting or constructability.

Table 10 – SDG&E Pipeline Projects
Mileage Summary

Line	As Filed (Miles)	Included in this Filing	
		(Miles)	(Feet)
49-11	6.30	0.960	5,068
49-13	3.46	3.175	16,761
49-15	6.60	2.790	14,732
49-28	4.89	2.600	13,729
Total	**21.25**	**9.525**	**50,290**

The scope reduction depicted above is primarily the result of scope validation activities or reductions in pipeline MAOP. Additionally, as indicated, some of the projects were divided into sections and some project sections may have either been included in a previous reasonableness review,[43] or will be included in a future reasonableness review.

IX. CONCLUSION

My testimony describes the pipeline project costs, disallowances, and other miscellaneous costs presented for review for reasonableness in this Application. These costs were incurred to accomplish Commission, State, and SoCalGas and SDG&E pipeline safety objectives. Extensive details providing additional supporting information documenting the reasonableness of the costs incurred are contained in the supporting workpapers and serve to demonstrate the prudent project execution and reasonableness of incurred costs. Based on the

[43] A.14-02-016, *Application of SoCalGas and SDG&E to Recover Costs Recorded in Their Pipeline Safety and Reliability Memorandum Accounts*, and A.16-09-005, *Application of SoCalGas and SDG&E to Recover Costs Recorded in the Pipeline Safety and Reliability Memorandum Account, the Safety Enhancement Expense Balancing Accounts and the Safety Enhancement Capital Cost Balancing Accounts*.

information contained in my testimony and supporting workpapers, the Commission should find reasonable the costs incurred in executing PSEP (which have already been reduced by disallowances) and approve full rate recovery of the project and miscellaneous costs presented for review in this Application.

This concludes my prepared Direct Testimony.