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

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

CHAPTER III

DIRECT TESTIMONY OF

RICK PHILLIPS

ON BEHALF OF

SOUTHERN CALIFORNIA GAS COMPANY

AND

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

September 2, 2016

TABLE OF CONTENTS

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 26 Pipeline Safety Enhancement Plan (PSEP) pipeline projects presented in this application and the reasonableness of (1) the $101.97 million in capital expenditures and $54.49 million in operating and maintenance (O&M) expenditures for the 26 pipeline projects included for review and rate recovery in this testimony; and (2) the $48 thousand capital credit[1] and $6.81 million in O&M expenditures associated with miscellaneous other costs incurred to execute PSEP. As part of this demonstration, I will explain the project cost components, Decision Tree, and other concepts approved in D.14-06-007.

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

Please note: For efficiency purposes and to facilitate the review process, detailed information for each project is contained in the associated project workpapers. The information contained in this chapter is designed to provide a summary of the projects and associated costs. Detailed information is provided in this chapter for the non-project specific costs.

[1] The capital credit is the net total of post-completion cost adjustments described in Section XI of my testimony.

II. PSEP MILEAGE RECONCILIATION

As required by D.14-06-007, a reconciliation of the "as filed" mileage with the actual mileage pressure tested or replaced is included in Tables 1 and 2 below for the projects addressed in this application:[2]

Table 1 - SoCalGas Pipeline Projects

Line	As Filed (Miles)	Included In This Filing (Miles)
1005	3.5	0.029 (151 ft.)
1011	5.14	0.077 (405 ft.)
1013	3.5	0.027 (140 ft.)
1014	0.003	0.003 (16 ft.)
1015 (North & South)	7.85	0.409 (2,161 ft.)
2000 West Sec (1,2,3)[3]	117.6	14.571
2001 West[4]	64.1	
2001 West A Sec (15,16)		0.006 (31 ft.)
2001 West B Sec (10,11,14)		2.939
2003 Sec (1,3,4)[5]	26.5	0.249 (1,315 ft.)
235 West Sawtooth Canyon	-[6]	0.324 (1,710 ft.)
235 West/44-654/235-335 Palmdale[7]		
235 West	3.1	0.031 (164 ft.)
44-654	0.01	0.047 (246 ft.)
235-335 Palmdale	-	-
33-120 Section 2[8]	1.25	0.279
35-20-N	0.01	0.013 (69 ft.)
36-37	0.02	0.012 (62 ft.)

[2] 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.
[3] Line 2000, because of its length, will be remediated in four phases: 2000-A, 2000-Bridge, 2000-C, and 2000 West. 2000-C has been regrouped with 2001-West-C and will be executed as one project under "2000-C/2001W-C Desert Bundle."
[4] Line 2001-West will be remediated as three projects: 2001 West-A, 2001 West-B, and 2001 West-C. This pipeline has been broken up into section to report schedule progress. 2001 West-C has been regrouped with 2000-C and will be executed as one project under "2000-C/2001W-C Desert Bundle."
[5] Line 2003 has been broken up into two separate projects for reporting schedule progress, Line 2003 Section 1, 3, 4 and Line 2003 Section 2.
[6] Filing mileage included in the 3.1 miles indicated for 235 West below.
[7] The 235 West/44-654/235-335 Palmdale Project is addressed in Chapter V (Mejia).
[8] Line 33-120 is being addressed under three separate projects.

36-9-09 North[9]	16.02	
36-9-09 North Section 2B		2.155
36-9-09 North Section 6A		0.916
36-1032 Sec (1,2,3)	1.54	0.653 (3,449 ft.)
38-539	12.08	2.613
406 Sec (1,2,2A,4,5)[10]	20.7	1.166
407 (North & South)	6.3	2.997
41-30-A	0.26	0.020 (107 ft.)
45-120 Section 1[11]	4.30	0.553
45-120X01	0.01	0.011 (57 ft.)
PDR Storage Phase 4 and 5[12]	1.92	0.269 (1,418 ft.)
TOTAL	**295.713**	**30.369 miles[13]**

Table 2 - SDG&E Pipeline Projects

Line	As Filed (Miles)	Included in This Filing (Miles)
49-14	2.45	0.032 (167 ft.)
49-22[14]	4.04	4.046
49-32	0.06	0.063 (332 ft.)
TOTAL	**6.55**	**4.141**

The scope reduction seen above is primarily the result of the scope validation of records or reductions in Maximum Allowable Operating Pressure (MAOP). Additionally, as indicated, some of the projects have been split into sections and were either included in A.14-12-016 or will be included in future applications.

III. DISALLOWED COSTS

In D.14-06-007, the Commission approved the proposed PSEP, with some limited exceptions, but did not authorize the pre-approval of PSEP implementation costs. D.14-06-007 (as modified by D.15-12-020) did, however, disallow certain specified costs discussed below.

[9] At the time of filing, the scope of the Line 36-9-09 North project was 16.01 miles, covering several non-contiguous segments crossing different jurisdictional boundaries. Therefore, Line 36-9-09 North is being addressed in ten different sections, two of which (2B and 6A) are included in this Application.
[10] Line 406 is being addressed under two separate projects.
[11] Line 45-120 is being addressed under two separate projects.
[12] Playa del Rey is being addressed under two separate projects.
[13] Values may not add to total due to rounding.
[14] Line 49-22 includes Section 1, National City and Section 2, Chula Vista.

Table 3 summarizes the disallowed costs as relevant to the projects presented for review in this application.

Table 3 - Disallowed Cost Summary ($000's)[15]

Disallowance Type	SoCalGas Costs	SDG&E Costs	Total Costs
Records Search[16]	$187	-	$187
Post-1955 PSEP Costs[17]	$6,411	$31	$6,442
Executive Incentive Compensation[18] [19]	$0	-	$0
Undepreciated Book Balances[20]	$231	-	$231
Total Disallowances	**$6,829**	**$31**	**$6,860**

Including the projects presented for review and recovery in A.14-12-016,[21] SoCalGas and SDG&E have acknowledged disallowances totaling approximately $25 Million. Table 4 below reflects the Post-1955 PSEP disallowances that have been removed from the project's cost included in this application.

[15] The costs were removed from the utilities' applicable regulatory accounts in the balances presented in Chapter XI (Austria).
[16] D.14-06-007, mimeo., at 39.
[17] D.14-06-007, mimeo., at 56-57 (Conclusions of Law 13 and 14); *see also* D.15-12-020, mimeo., at 23 (Ordering Paragraph 1).
[18] D.14-06-007, mimeo., at 38.
[19] SoCalGas and SDG&E included $773 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 incentive compensation component of that amount or $189. This figure, however, rounds to $0 in Table 3.
[20] D.14-06-007, mimeo., at 57 (Conclusion of Law 15); *see also* D.15-12-020, mimeo., at 24 (Conclusion of Law 10).
[21] Adjusted to reflect additional disallowances per D.15-12-020.

Table 4 - Disallowed Post-1955 PSEP Costs by Project ($000's)

Line	Capital Costs	O&M Costs	Total Costs
1005	$4	-	$4
1011	-	-	-
1013	$ 31	-	$31
1014	$ 3	-	$3
1015 (North & South)	$ 8	$3,071	$3,079
2000 West Sec (1,2,3)	$1	$68	$69
2001 West A Sec (15,16)	-	-	-
2001 West B Sec (10,11,14)	-	-	-
2003 Sec (1,3,4)	$40	-	$40
235 West Sawtooth Canyon	-	-	-
235 West/44-654/235-335 Palmdale[22]	$96	-	$96
33-120 Section 2	-	-	-
35-20-N	$17	-	$17
36-1032 Sec (1,2,3)	-	-	-
36-37	$2	-	$2
36-9-09 North Section 2B	-	-	-
36-9-09 North Section 6A	-	-	-
38-539	-	-	-
406 Sec (1,2,2A,4,5)	-	-	-
407 (North & South)	-	$3	$3
41-30-A	-	-	-
45-120 Section 1	-	-	-
45-120X01	-	-	-
49-14	$31	-	$31
49-22	-	-	-
49-32	-	-	-
PDR Storage Phase 4 and 5	-	$3,067	$3,067
Total	**$233**	**$6,209**	**$6,442**

The project workpapers contain project-specific disallowance discussion. Included below is a brief overview of how SoCalGas and SDG&E have calculated the above disallowances.

[22] The disallowance for this project bundle is addressed in Chapter V (Mejia).

A. Post-1955 Hydrotest Projects without Sufficient[23] Record of a Pressure Test

For the hydrotest projects presented in this application, SoCalGas and SDG&E have indicated the pipeline mileage associated with post-1955 pipe without sufficient record of a pressure test. Based on the mileage associated with post-1955 mileage without sufficient record of a pressure test, SoCalGas and SDG&E have acknowledged a disallowance to the total project costs. Specifically, SoCalGas and SDG&E calculate the percentage of pipe in the project without sufficient record of a pressure test. That percentage is then used to determine the costs subject to disallowance.

Where incidental mileage has been included only to facilitate the constructability of post-1955 hydrotest projects without sufficient record of a pressure test, SoCalGas and SDG&E have included that mileage in calculating the disallowance. Where accelerated mileage was included with a post-1955 hydrotest project without sufficient record of a pressure test, the accelerated mileage has been included for review and recovery because it would otherwise need to be addressed as part of a later phase of PSEP. Accelerated mileage includes Phase 1B mileage (pre-1946, non-piggable pipe) and Phase 2 mileage. PSEP Phase 2 includes pipelines without record of a pressure test or with record of a pressure test but not to 1.25 MAOP in less populated areas (Phase 2A); and pipelines with record of a pressure test, but without record of a pressure test to modern (49 Code of Federal Regulations Part 192, Subpart J) standards (Phase 2B).[24]

[23] 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.

[24] 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, mimeo., at 18). The Commission's new requirements will require SoCalGas and SDG&E to locate records of pressure testing in accordance with Subpart J standards or conduct such pressure tests or replace the pipeline.

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

For the replacement projects presented in this application, SoCalGas and SDG&E have indicated 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 have calculated a disallowance based on SoCalGas and SDG&E's average cost of pressure testing.[25] Specifically, SoCalGas and SDG&E have calculated a system average cost to pressure test (as of June 2015, the time period when these projects completed construction, that amount was $1.7 million per mile) and multiplied that number by the length of pipe subject to a disallowance. The resultant amount is acknowledged as a disallowance. In this way, 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."[26]

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 otherwise need to be addressed as part of a later phase of PSEP, and the incidental mileage has record of a pressure test – and, unlike the pressure test disallowance, SoCalGas and SDG&E are absorbing undepreciated book value for the entirety of the project. In other words, customers have the benefit of a brand new pipe, and the remaining book value of the incidental and accelerated pipe is absorbed by shareholders.

Although SoCalGas and SDG&E have calculated the disallowances consistent with D.14-06-007, in preparing this application SoCalGas and SDG&E have noted that the method results in unexpectedly small disallowances for short replacement segments. SoCalGas and SDG&E

---

[25] D.14-06-007, mimeo., 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.") D.14-06-007, mimeo., at 57 (Conclusion of Law 14); D.15-12-020, mimeo., 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").

[26] D.14-06-007, mimeo., at 36.

respectfully request the Commission confirm that the above calculation method is correct or provide guidance on alternative approaches.

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

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

D. PSEP Executive Incentive Compensation

As explained in the chapters that follow, SoCalGas and SDG&E management maintains oversight of PSEP. In order to comply with the Commission's direction to exclude executive incentive compensation costs, however, SoCalGas and SDG&E generally do not include any executive compensation costs for recovery. In so doing, SoCalGas and SDG&E alleviate the need to separately track executive incentive compensation. In the event executive compensation is included for recovery, SoCalGas and SDG&E manually remove the component of the executive compensation associated with incentive compensation.

E. Costs Associated with Searching for Test Records of Pipeline Testing

SoCalGas and SDG&E have tracked costs associated with their search for pressure test records. The initial record search costs were included as a disallowance in SoCalGas and SDG&E first PSEP after-the-fact reasonableness review – A.14-12-016. Additional disallowances are acknowledged in this application.

IV. PROJECT COST COMPONENTS

The costs presented in this chapter are those incurred through March of 2016. Accounting adjustments made between March 2016 and the date of this application are addressed in Chapter XI (Austria). The project costs included in this chapter include costs incurred in direct support of an individual hydrotest, replacement, or abandonment project;

project support costs not attributable to a specific project, but incurred to support PSEP projects;[27] and indirect costs.[28] The project costs include both capital and operations and maintenance (O&M). Depending on the specifics of the projects, a project may include O&M, or capital, or both. For example, there is a capital cost component to certain pressure test projects. As part of the normal pressure testing process, a section of the existing pipeline is removed to accommodate temporary test heads which are used to conduct the pressure test. After the line is tested and the temporary test head is 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 is new pipe and is capitalized in accordance with SoCalGas and SDG&E's accounting policy.

V. DECISION TREE

In addressing pipelines set to be tested or replaced through SoCalGas and SDG&E's PSEP, a foundational decision point is whether to pressure test or replace that pipeline segment.[29, 30] SoCalGas and SDG&E's Decision Tree methodology provides SoCalGas and SDG&E's pressure test versus replace decision-making process and is illustrated below:

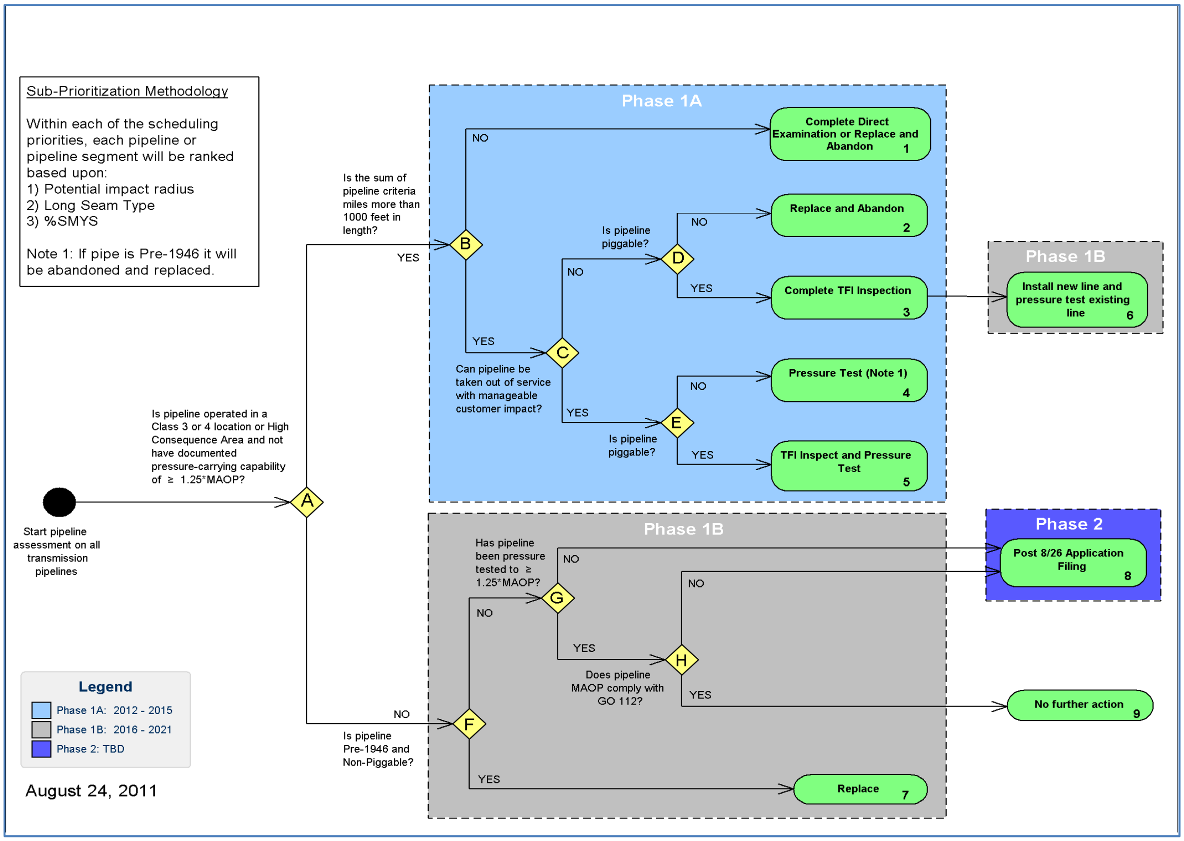
---

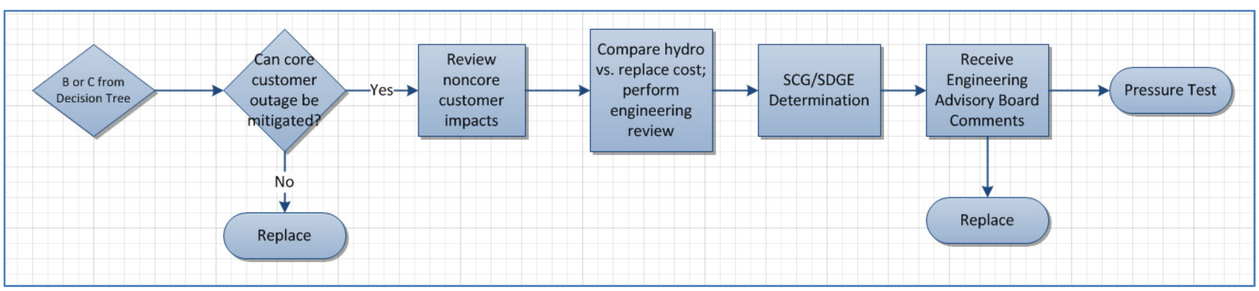
[27] PSEP organizational costs not attributable to a specific project (PSEP GMA costs) are allocated to hydrotest, replacement, abandonment, and valve projects and discussed in Chapters VII (Mejia) and VIII (Tran).

[28] 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 recovery in this Application and further discussed in Chapter IX (Huleis).

[29] The Decision Tree also includes Direct Examination instead of replacing or abandoning. However, subsequent to this filing, a state law went into effect that requires pipelines be pressure tested or replaced (*see* California Public Utilities Code Section 958(c)). This law eliminates the option for SoCalGas and SDG&E to utilize direct examination in lieu of pressure testing or replacing.

[30] The Decision Tree also proposed to conduct in-line inspections using transverse field inspection (TFI) technology prior to pressure tests in order to determine the effectiveness of TFI in discovering pipeline flaws and anomalies. 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 costs by allowing some Phase 2 lines that cannot be pressure tested with manageable customer impacts to be addressed using TFI rather than replacement. Subsequent to the filing of our PSEP, however, a state law went into effect that requires all transmission pipelines to either be pressure tested or replaced (*see* California Public Utilities Code Section 958(c)). As such, validating TFI as an equivalent assessment method to pressure testing is no longer projected to potentially reduce Phase 2 PSEP costs. SoCalGas and SDG&E have nevertheless conducted some TFI assessments as an additional safety enhancement measure





The Decision Tree uses a step-by-step analysis of pipeline segments to allocate pipeline 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 determine other factors that may impact whether

---

and to validate the effectiveness of the TFI technology. The costs for those TFI assessments are not included in this application.

to pressure test or replace the segment. These steps are depicted in the Replacement Decision Tree.[31] The Replacement Decision Tree concepts were similarly adopted in D.14-06-007.[32, 33]

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 its 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 at 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 their engineering expertise and knowledge of the pipelines they operate, Utilities are in the best position to 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 set to be replaced. As embodied in the Decision Tree, SoCalGas and SDG&E anticipate replacing and abandoning these short segments. As described in the original application, it will usually be more cost effective to replace these short segments. SoCalGas and SDG&E may, however, engage in

[31] As presented in A.11-11-002 (Rebuttal Testimony of Rick Phillips) at 8.
[32] D.14-06-007, mimeo., at 2 and 59 (Ordering Paragraph 1).
[33] 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 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 (D.14-06-007, mimeo., at 28).

further review during the early planning stage to determine the most appropriate action. For example, costs and other engineering factors may be 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 of the pipeline system.

B. Segments Greater than 1,000 Feet

Pipeline segments greater than 1,000 feet are further separated based on whether the pipeline can be taken out of service per the Decision Trees. Pipeline segments that are greater than 1,000 feet in length that can be removed from service for pressure testing per the Decision Trees 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 appropriate pressure test or replace decision is based on customer impact and engineering and cost analysis; analysis aimed at minimizing customer impacts and maximizing safety and cost-effectiveness.

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"[34] and that address "all natural gas transmission pipeline…even low priority segments,"[35] while also "[o]btaining the greatest amount of safety value, i.e., reducing safety risk, for ratepayer expenditures."[36] 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.

---

[34] D.11-06-017, mimeo., at 19.
[35] D.11-06-017, mimeo., at 20.
[36] D.11-06-017, mimeo., at 22.

Accelerated miles are miles that would otherwise be addressed in a later phase of PSEP under the approved prioritization process, but are being advanced to Phase 1A to realize operating and cost efficiencies. Accelerated miles may include Phase 1B or Phase 2. Phase 1B includes pipelines installed before 1946 that are unpiggable. Phase 2 includes pipelines without sufficient record of a pressure test in less populated areas (Phase 2A) or pipelines with record of a pressure test, but without record of a pressure test to modern – Subpart J – standards (Phase 2B). Incidental miles are miles not scheduled to be addressed in PSEP, but are included where their inclusion is determined to improve cost and program efficiency, address implementation constraints, or facilitate continuity of testing.[37] 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 executing a project around them.[38]

VII. SUMMARY OF PROJECT COSTS

For efficiency purposes and to facilitate the review process, detailed information for each project is contained in the associated project workpapers. The information below is designed to provide a summary of the projects and associated costs.

[37] An additional benefit of incidental mileage is to further confirm the integrity of the pipeline.
[38] 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.

A. Replacement Projects

Table 5 – Replacement Project Costs (000's)

Line	SoCalGas Cost	SDG&E Cost	Total Cost
1005	$6,476	-	$6,476
1011	$2,657	-	$2,657
1013	$2,738	-	$2,738
1014	$928	-	$928
2001 West A Sec (15,16)	$822	-	$822
235 West Sawtooth Canyon	$2,050	-	$2,050
33-120 Section 2	$7,634	-	$7,634
35-20-N	$285	-	$285
36-1032 Sec (1,2,3)	$10,953	-	$10,953
36-37	$1,202	-	$1,202
38-539	$16,916	-	$16,916
41-30-A	$484	-	$484
45-120X01	$857		$857
45-120 Section 1	$6,418	-	$6,418
49-14	-	$4,702	$4,702
49-32	-	$4,393	$4,393
Total Cost	**$60,420**	**$9,095**	**$69,515**

B. Pressure Test Projects

Table 6 – Pressure Test Project Costs (000's)

Line	SoCalGas O&M Cost	SoCalGas Capital Cost	Total Cost
PDR Storage Phase 4 and 5	$5,336	-	$5,336
1015 (North & South)	$5,241	$481	$5,722
2000 West Sec (1,2,3)	$16,403	$8,436	$24,839
36-9-09 North Section 2B	$3,146	-	$3,146
36-9-09 North Section 6A	$2,785	-	$2,785
407 (North & South)	$6,431	$537	$6,968
Total Cost	**$39,342**	**$9,454**	**$48,796**

C. Combination Replacement and Pressure Test Projects

Table 7 – Combination Replacement and Pressure Test Project Costs (000's)

Line	SoCalGas Capital Cost	SoCalGas O&M Cost	Total Cost
2001 West B Sec (10,11,14)	$4,553	$8,472	$13,025
2003 Sec (1,3,4)	$7,019	$2,592	$ 9,611
406 Sec (1,2,2A,4,5)	$7,255	$3,220	$10,475
Total Cost	**$18,827**	**$14,284**	**$33,111**

D. Abandonment Project

Table 8 – Abandonment Project Costs (000's)

Line	SoCalGas Capital Cost	SDG&E Capital Cost	Total Cost
49-22	-	$5,034	$5,034
Total Cost	**-**	**$5,034**	**$5,034**

VIII. MISCELLANEOUS COSTS

SoCalGas and SDG&E have also incurred various miscellaneous costs necessary to execute PSEP. Table 9 includes a summary of these costs:

Table 9 – Summary of Miscellaneous Costs ($000'S)

	SoCalGas Costs	SDG&E Costs	Grand Total
Facilities Lease Expense	$5,553	$685	$6,238
Descoped Projects	$199	-	$199
Post-Completion Adjustments	$320	-	$320
TOTAL	**$6,072**	**$685**	**$6,757**

IX. FACILITIES LEASE COSTS

Table 10 – Facilities Lease Costs ($000'S)

	SoCalGas Costs	SDG&E Costs	Grand Total
Facilities Lease Expense (O&M)	$5,553	$685	$6,238

The costs included in Facilities Lease Expense consist of: (1) lease expense associated with the 22nd and 23rd floor at the Gas Company Tower, (2) a short-term lease at the Gas Company Tower to house PSEP personnel prior to the availability of the 22nd and 23rd Floor, (3) PSEP's portion of leased classroom space to conduct training of PSEP field personnel, and (4) the lease of office space to house SDG&E PSEP personnel.

As described in Chapter II (Phillips), because PSEP is an incremental project and there were insufficient company personnel available to undertake a program the size of PSEP, additional internal and external personnel were hired. Similarly, there were also no existing facilities available to house these personnel. Therefore, additional office space was required. SoCalGas and SDG&E leased two additional floors at the Gas Company Tower to house the personnel to run PSEP. In addition, office space was leased in the San Diego area to house a smaller group of PSEP employees working on projects in the SDG&E service territory. Also included in the lease costs was a short term lease for part of a floor at the Gas Company Tower to accommodate the PSEP team prior to the availability of the permanent space and a portion of a leased classroom to accommodate technical training for field personnel.

In acquiring additional space, SoCalGas has consistently worked to co-locate certain departments and personnel to maximize communication and collaboration. These efforts are reasonable and responsive to the myriad of interactions that occur with and within PSEP. For example, design engineers and project engineers work closely together as the project planning and scope evolve into a detailed design document in order for materials to be ordered. Besides regularly-scheduled project update meetings, informal interaction occur daily as issues arise which are more effectively addressed in person. Indeed, in developing the PSEP organization, the space planning strategy undertaken for the placement of specific groups on the two floors took into consideration which groups interact more frequently and placed those resources in close proximity to each other. Some groups (*e.g.*, Project Engineering, Cost and Schedule

Specialists) are integrated by project portfolio to further facilitate collaboration. The PSEP groups occupying the two floors include:

- Project Managers/Project Engineers
- Design Engineers
- Survey personnel
- Material acquisition and tracking personnel
- Contract Specialists
- Land rights personnel
- Environmental personnel
- Non-Environmental Permits personnel
- Construction Specialists
- Scheduling and Cost Specialists
- Stakeholder outreach personnel
- PSEP Engineering
- PMO

In contrast to the centralized approach taken by SoCalGas and SDG&E, locating PSEP personnel on different floors and/or locations would negate the co-location benefits described.

Further, a concerted effort was also made to maximize the seating capacity of the 22nd and 23rd Floor through the use of smaller touchdown workstations and shared offices and workstations. Table 11 depicts the seating capacity of these floors.

Table 11 - Seating Capacity of Gas Company Tower Floors 22 and 23

Date	**Seating Capacity 22nd Floor**	**Seating Capacity 23rd Floor**	**Total**
June 2014	180	142	322
December 2015	198	186	384

For the office space leased in order to house the team working on SDG&E PSEP projects, a third party commercial brokerage firm was retained to provide alternatives given the space and related requirements to house approximately 50 employees/contractors and provide 5 hoteling spaces. Eleven alternative locations were provided to SoCalGas and SDG&E for their review. After an initial review, the 11 locations were narrowed to three for further evaluation. The location selected (Viewridge Business Park) was immediately available for occupancy, did not require any tenant improvements prior to occupancy, and was of the required size. Further, on a cost per square foot basis, the Viewridge location was the second lowest of the 11 alternatives (the lowest was five cents per square foot less).

X. DESCOPED PROJECTS

During the course of Phase 1A, planning began on a number of projects that were later descoped or cancelled because of either scope validation or the Maximum Allowable Operating Pressure (MAOP) was lowered to a level sufficient to bring the line outside the scope of PSEP. SoCalGas and SDG&E include for recovery $199,000 for the cost of descoped projects. The amount included for recovery is associated with pipelines installed prior to 1956 and excludes as indicated in Table 12 record search costs associated with these lines.

Table 12 -Descoped Projects Costs (000's)

Line	Vintage	Total Cost	Records Search Disallowance	Net Total	Reason
35-20-A	Pre-1946	$30	($2)	$28	Scope Validation
38-523	1946-1955	$74	($5)	$69	Scope Validation
41-6045	1946-1955	$56	-	$56	Scope Validation
41-80	1946-1955	$46	-	$46	Scope Validation
TOTAL		**$206**	**($7)**	**$199**	

The descoped project costs directly contributed towards the implementation of the projects prior to cancellation and were prudently and reasonably incurred.

XI. POST-COMPLETION COST ADJUSTMENTS

Post-completion cost adjustments in the amount of $320,000 associated with lines that were presented for review (including descoped projects) in A.14-12-016 are included for recovery in this application. Table 13 summarizes the costs by line:

Table 13 - Post-Completion Adjustment Costs ($000's)

Line	O&M Costs	Capital Costs	Total Costs
Line 2000-A	$282	($167)	$115
42-66-1/42-66-2	-	$17	$17
Playa Del Rey Storage (Phases 1-3)[39]	$67	-	$67
SL 38-528	$2	-	$2
Line 41-04-I	$4	-	$4
Line 2001 East	$13	-	$13
Facilities Build-Out Costs	-	$102	$102
TOTAL	**$368**	**($48)**	**$320**

Post-completion adjustments occur when invoices or accounting adjustments are received after the filing of 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 and may result in increased or decreased costs. For the above projects, the primary categories of post-completion adjustments are contractor invoices, accrual reversals, and Company labor hour/journal entry adjustments.

Processes have been put in place to validate invoices are received and paid prior to the completion of Stage 7 (Closeout). This minimizes cost adjustments, although it is not anticipated that all adjustments will be eliminated.

XII. CONCLUSION

My testimony describes the pipeline project costs, disallowances, and other miscellaneous costs presented for reasonableness review in this application. These costs were

[39] $67K is the net cost submitted for recovery after deducting Post-1961 footage without sufficient record of a pressure test to 1.25 MAOP (23% of total PSEP footage and costs) consistent with the original submittal for cost recovery in A.14-12-016 (See Chapter III, Amended Prepared Testimony of Rick Phillips, A.14-12-016, pg. 9)

incurred to accomplish the Commission's, Legislature's, and SoCalGas and SDG&E's pipeline safety objectives. Extensive detail providing additional supporting information documenting the reasonableness of the costs incurred are contained in the workpapers and serves to demonstrate the prudent project execution and reasonableness of incurred costs. Based on the information contained in my testimony and supporting workpapers, the Commission should find the costs reasonable and approve full rate recovery – minus acknowledged disallowances – for the projects and miscellaneous costs presented for recovery in this chapter.

This concludes my prepared direct testimony.