BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Investigation Into the November 2016 Submission of San Diego Gas & Electric Company's Risk Assessment and Mitigation Phase.	Investigation 16-10-015 (Filed October 27, 2016)
And Related Matter.	Investigation 16-10-016 (Filed October 27, 2016)

COMPLIANCE FILING OF THE SECOND INTERIM SPENDING ACCOUNTABILITY REPORT OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) AND SOUTHERN CALIFORNIA GAS COMPANY (U 904 G)

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October 6, 2017

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Pursuant to Ordering Paragraph (OP) 11 of decision (D.) 16-06-054 and in accordance with D.17-01-012, San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (jointly, the Utilities) hereby submit their Second Interim Spending Accountability Report (Second Interim Report) attached hereto as Appendix A. This Second Interim Report is timely filed and served in accordance with OP 11(b) of D.16-06-054, OP 2 of D.17-01-012, and Executive Director Timothy Sullivan's letter granting the Utilities' extension request on August 22, 2017.[1]

OP 11 required SDG&E and SoCalGas to compare Test Year 2016 authorized spending to actual 2014 and 2015 spending on a limited set of risk mitigation projects in a first interim accountability report and to propose a methodology for reporting and comparing the projected versus actual benefits of its risk mitigation activities (First Interim Report). A subsequent

[1] The Utilities submitted a letter to on August 15, 2017 requesting an extension of time to file their Test Year (TY) 2019 General Rate Case (GRC) applications from September 1, 2017 to October 6, 2017. Because D.17-01-012 requires the Utilities to file the Second Interim Report in their TY 2019 GRC, this extension also impacted the submission date of this report. The extension request was granted on August 22, 2017.

Commission decision, D.17-01-012, which closed the above-captioned proceeding, Application (A.) 14-11-003/-004, (cons.), required SDG&E and SoCalGas to file their First Interim Report in their Risk Assessment Mitigation Plan (RAMP) proceeding, Investigation (I.) 16-10-015/-016 (cons.), which was filed on June 30, 2017. Further, D.17-01-012 requires that the Second Interim Report, which adds actual 2016 spending, shall now be filed in the TY 2019 GRC Applications of SDG&E and SoCalGas.[2] Accordingly, the compliance filing herein attaching the Second Interim Report is being concurrently filed in the Utilities' TY 2019 GRC Applications.

Further, OP 11 directed SDG&E and SoCalGas to discuss the format of these reports with the Safety and Enforcement Division (SED) and the Energy Division (ED) before the due dates of these reports. SDG&E and SoCalGas met on March 6 and May 25, 2017 with SED and ED representatives, and communicated in the interim, "to determine the exact format and content of these reports."[3] The format and content of the Second Interim Report attached hereto has been prepared in accordance with those discussions and with the requirements set forth in D.16-06-054, OP 11. The Utilities have also updated the first accountability report to (1) include figures for 2016 in this second report; (2) correct any identified errors; and (3) incorporate relevant feedback received to date based on follow-up meetings with SED, ED, and Office of Safety Advocates (OSA).

Respectfully submitted,

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October 6, 2017

[2] D.17-01-012 at OP 2.
[3] D.16-06-054 at 41.

APPENDIX A

SECOND INTERIM SPENDING ACCOUNTABILITY REPORT

Southern California Gas Company and San Diego Gas & Electric Company

Second Interim Spending Accountability Report

October 6, 2017

1. Introduction

The California Public Utilities Commission (Commission) adopted Decision (D.) 16-06-054, issued on July 1, 2016, addressing the Test Year (TY) 2016 General Rate Case (GRC) of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (collectively, the Utilities). D.16-06-054 orders the following:

a. SDG&E and SoCalGas shall each file a Spending Accountability Report within one year from the issuance date of D.16-06-054.

   i. The Spending Accountability Report shall compare Test Year 2016 authorized spending to actual 2014 and 2015 spending on a limited set of risk mitigation projects, and to propose a methodology for reporting and comparing the projected versus actual benefits of its risk mitigation activities.[1] The proposed methodology with respect to benefits should include relevant performance metrics.[2]

b. A second Spending Accountability Report shall be filed and served within two years from the issuance of D.16-06-054, which is to include actual 2016 spending.[3]

c. SDG&E and SoCalGas are directed to discuss the format of these reports with the Safety and Enforcement Division (SED) and the Energy Division (ED) before the due dates of these reports.[4]

In accordance with D.16-06-054, the limited set of risk mitigation projects within the scope of these reports includes:[5]

> For SDG&E's electric operations – the report shall include wildfire risk projects, activities and costs, and specific spending associated with mitigation projects SDG&E had identified as part of the wildfire mitigation program.[[6]] For example, specific Fire Risk Management (FiRM) projects identified in testimony and in the SED report[7] include, replace live front equipment; weather instrumentation; Powerworkz; C1215 Fire

[1] D.16-06-054, Ordering Paragraph (OP) 11.

[2] *Id*. at 39.

[3] *Id*. at OP 11.

[4] *Id*. at 41 and OP 11.

[5] *Id*. at 39-41 (internal citations omitted).

[6] Although this excerpt from D.16-06-054 identifies the listed projects as being part of SDG&E's wildfire mitigation program, SDG&E notes that not all of these programs are wildfire-related, or were identified as such in testimony, as described in Section 2.

[7] SED prepared a safety report, which evaluated selected safety and risk program areas of the TY 2016 GRC applications of SDG&E and SoCalGas in Applications (A.) 14-11-003 and A.14-11-004.

> Mitigation; FiRM Phases 1, 2 & 3, C441 Pole Loadings; Aerial marking; CNF Brakes; and SF6 [Sulfur Hexafluoride] switch replacement.
>
> Among the metrics the utility might include in the report are the following: data on vegetation inspections, data on hardware failures, equipment failures, and wire failures.
>
> Additionally, the report should cover the specific component replacement/maintenance programs that were identified in CCUE's [Coalition of California Utility Employees] direct testimony including: circuit breakers, capacitors, SF6 Switches, underground switches, and associated overhead.
>
> Maintenance and repair/replacement of these components are considered mitigation for SDG&E's identified priority risk of electric service disruptions. Associated metrics should include a comparison of proposed versus actual replacement rates, as well as changes in relevant reliability index statistics. The level of spending the Commission has approved for these activities, as well as actual spending, should both be tracked.
>
> For SDG&E's gas operations – The report should focus on the risks associated with gas safety incidents, especially third-party dig-ins, and elements of the Distribution Integrity Management Program (DIMP). In addition to DIMP, the report should include projects associated with replacing aging infrastructure, especially Aldyl-A pipe.
>
> For SoCalGas – the report should include projects associated with reducing gas safety risks, including projects, activities, and costs associated with DIMP, Transmission Integrity Management Program (TIMP), and the Storage Integrity Management Program (SIMP).

With respect to proposing a methodology to "report and compare projected versus actual benefits of their risk mitigation activities"[8] for the reported years, in these reports, the Utilities put forth metrics as a means to measure benefits. The metrics will serve two purposes: (1) explain variances in spending; and (2) provide insight into where improvements towards mitigating risks can be made. The proposed metrics are discussed in more detail in Section 1d.

A subsequent Commission decision, D.17-01-012, advised that SDG&E and SoCalGas should file their interim report in their Risk Assessment Mitigation Phase (RAMP) proceeding. After receiving email guidance on June 30, 2016 from Administrative Law Judge (ALJ) John Wong, the Utilities concurrently filed their first interim spending accountability report (referred to herein as the "First Interim Report") both in Application (A.) 14-11-003/-004 (cons.) and in their pending RAMP proceeding, Investigation (I.) 16-10-015/-016 (cons.), and served the report upon the official service lists for those two proceedings. Further, D.17-01-012 requires that the second report (referred to herein as the "Second Interim Report"), which adds actual 2016 spending, shall now be filed in the TY 2019 GRC Applications of SDG&E and SoCalGas.[9] The Utilities

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[8] D.16-06-054 at 39.

[9] D.17-01-012 at OP 2.

submitted a letter to Executive Director Timothy Sullivan on August 15, 2017 requesting an extension of time to file their TY 2019 GRC applications from September 1, 2017 to October 6, 2017. Because D.17-01-012 requires the Utilities to file the Second Interim Report in their TY 2019 GRC, this extension will also impact the submission date of the accountability report. The extension request was granted on August 22, 2017.

Beginning with the information outlined in D.16-06-054, the Utilities met on March 6 and May 25, 2017 with SED and ED, and communicated in the interim, "to determine the exact format and content of these reports."[10] The format and content provided herein is a product of those discussions.

In this Second Interim Report, the Utilities have updated the First Interim Report to (1) include figures for 2016; (2) correct any identified errors; and (3) incorporate relevant feedback received to date based on follow-up meetings with SED, ED, and Office of Safety Advocates (OSA). The subsequent sections below (Sections 2, 3 and 4) provide a comparison of authorized spending to actual spending,[11] variance explanations and metrics for SDG&E's Electric Operations, SDG&E's Gas Operations and SoCalGas' Gas Operations. This Second Interim Report is timely filed in accordance with D.16-06-054, D.17-01-012, and the Executive Director's grant of the Utilities' extension letter request.

a. Background

In D.14-12-025, the Commission adopted a risk-based decision-making framework into the Rate Case Plan (RCP) for the energy utilities' GRCs. This risk-based decision-making framework was developed as a result of Senate Bill (SB) 705 (Statutes of 2011, Chapter 522), which declared in Public Utilities Code Section 963(b)(3):

> It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.

In 2014, the California Legislature amended the Public Utilities Code by adding Section 750, which directed the Commission to "develop formal procedures to consider safety in a rate case application by an electrical corporation or gas corporation."[12] As a result of these directives, D.14-12-025 adopted a risk-based decision-making framework for the large energy utilities, including SDG&E and SoCalGas. This framework consists of the following:

> For the large energy utilities, this will take place through two new procedures, which feed into the GRC applications in which the utilities request funding for such safety-related

[10] D.16-06-054 at 41.

[11] SoCalGas and SDG&E's Second Interim Report reports regulatory account balances as recorded through December 31 of the applicable year. Any adjustments that may be necessary are recorded in the year the adjustment is discovered, which corrects the cumulative balance recorded at that point in time.

[12] SB 900 (Statutes of 2014, Chapter 552).

> activities. These two procedures are: (1) filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, which are to be consolidated; and (2) a subsequent Risk Assessment Mitigation Phase (RAMP) filing in an Order Instituting Investigation for the upcoming GRC wherein the large energy utility files its RAMP in the S-MAP reporting format describing how it plans to assess its risks, and to mitigate and minimize such risks. The RAMP submission, as clarified or modified in the RAMP proceeding, will then be incorporated into the large energy utility's GRC filing. In addition, the large energy utilities will be required to file annual reports following their GRC decisions.
>
> It is our intent that the adoption of these additional procedures will result in additional transparency and participation on how the safety risks for energy utilities are prioritized by the Commission and the energy utilities, and provide accountability for how these safety risks are managed, mitigated and minimized.[13]

Although the Utilities filed their TY 2016 GRC prior to the issuance of D.14-12-025, D.16-06-054 ordered these interim accountability reports "[i]n order for the Commission and the Applicants to gain some familiarity and understanding with these reporting requirements during the TY 2016 GRC cycle, and to obtain the necessary data and metrics on safety, risk mitigation and accountability established by the framework in D.14-12-025."[14] Thus, the Commission focused on a limited set of risk mitigation projects for the TY 2016 GRC cycle, recognizing that future work would occur in Phase 2 of the S-MAP to refine future reporting requirements.

Thus, it is important to recognize that the First and Second Interim Reports cover years during the TY 2012 and TY 2016 GRC cycles, for which the Utilities filed applications before the risk-informed GRC framework was adopted, and during which the Utilities have undertaken the transitional process of implementing this framework. Accordingly, the reports reflect a transitional time period, and the risk mitigation projects in the reports predate the Utilities' November 30, 2016 RAMP Report under the new framework. Reports on risk mitigation projects here thus do not reflect the Utilities' comprehensive safety risk showing presented in their RAMP Report, nor the framework under which the Utilities developed that showing. Accountability reporting for the Utilities' first RAMP showing will not occur until 2020.[15]

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[13] D.14-12-025 at 2-3. These directives are also consistent with the Commission's Safety Action Plan and Regulatory Strategy, as updated in February 2016. The Commission's Safety Action Plan includes action items, such as Energy Division staff reports on safety-related expenditures, and safety review and activity reporting in GRCs by SED.

[14] D.16-06-054 at 39.

[15] D.14-12-025 states on p. 46 that the accountability reports "shall report on the activities and spending the utility undertook during the GRC test year, and during each attrition year." D.14-12-025 on page 47 also sets a timeline for submitting the annual accountability reports: "SoCalGas' [accountability] reports to be filed by July 31 after the applicable reporting period; and SDG&E's reports to be filed by September 30 after the applicable reporting period." Accordingly, the Utilities' first post-RAMP accountability reports will be submitted in 2020, after their 2019 GRC test years.

Furthermore, as explained in Sections 1b and 1c, the authorized and actual non-balanced spending in 2014 and 2015 was determined by the authorized revenue requirement established over two different GRC cycles (*i.e.*, TY 2012 GRC for Operations and Maintenance (O&M) and TY 2016 GRC for capital).

b. General Rate Case Cycles of the Utilities

The Utilities file GRC Applications with the Commission seeking authorization of a revenue requirement to recover the reasonable costs forecasted to incur in the test year,[16] and a mechanism for adjusting the revenue requirement annually during the post-test years,[17] for a total GRC period that typically spans three years. A revenue requirement is the amount of money the Utilities are allowed to collect, or recover, from their customers through rates.[18]

The final outcome of a GRC is a Commission-approved test year revenue requirement comprising of O&M and capital funding for the forecast years that compound annually up to the test-year. Additionally, a post-test year mechanism is approved generally for escalation on the test year revenue requirement. These approvals may or may not be the same as originally presented by the Utilities.

To illustrate the GRC cycles, the diagram below demonstrates the Utilities' last two GRC cycles as well as this TY 2019 GRC filed on October 6, 2017.

[16] A GRC follows the Commission's approved Rate Case Plan, which outlines the required submittals, procedures, and deadlines associated with a GRC. The Rate Case Plan utilizes a "base-year/test-year" approach to GRC ratemaking. Pursuant to the Rate Case Plan, the GRC typically consists of testimony and workpapers justifying forecasted O&M and capital costs in a future period. The last recorded year available forms the "Base Year." The year for which the Commission is formally approving the revenue requirement, and when new rates are to take effect, is called the "Test Year." The Utilities' showing provides recorded amounts for the base year and annual forecasts as a means to get to the test year. The annual forecasts provided between the base year and test year are referred to as "Forecast Years."

[17] For years 2 and 3 of the GRC cycle (and an additional year 4 proposed in this TY 2019 GRC filing), referred to as post-test years or attrition years, the Utilities also propose a post-test year mechanism. Ultimately, the GRC decision will prescribe how to adjust the test year revenue requirement for inflation and other factors that may affect costs, such as additional capital projects between test years.

[18] Generally, the Utilities' GRCs are presented in direct, base year dollars and converted into a test year revenue requirement using a ratemaking model, the Results of Operation (RO) model. The process by which the RO model converts the direct, base year dollars into a test year revenue requirement includes the escalation of costs (converting base year dollars into test year nominal dollars), intercompany billings between the Utilities, applying overheads (such as benefits) to capital projects, and converting the capital forecasts into capital-related costs (depreciation, taxes, and return).

Diagram 1: GRC Cycles of SoCalGas and SDG&E[19]

2012 GRC Proceeding	
Base Year	2009
Forecast Year	2010
Forecast Year	2011
Test Year	**2012**
Post-Test Year	2013
Post-Test Year	2014
Post-Test Year	2015

2016 GRC Proceeding	
Base Year	2013
Forecast Year	2014
Forecast Year	2015
Test Year	**2016**
Post-Test Year	2017
Post-Test Year	2018

2019 GRC Proceeding	
Base Year	2016
Forecast Year	2017
Forecast Year	2018
Test Year	**2019**
Post-Test Year	2020
Post-Test Year	2021

The Utilities provided the requested information, as discussed in Sections 1 and 1a herein, for the years 2014 through 2015, in the First Interim Report. The Utilities "shall compare Test Year 2016 authorized spending to actual 2014 and 2015 spending."[20] As noted in Sections 1a and 1c, years 2014 and 2015 were authorized by the Commission during the TY 2012 GRC proceeding in D.13-05-010.[21] However, the 2016 amounts for authorized were approved by the Commission in the 2016 GRC proceeding in D.16-06-054.[22] Accordingly, as explained in Section 1c, the non-balanced capital projects were authorized over two different GRC cycles, causing the "authorized" three-year period (2014-2016) reported herein to not be an ideal comparison against "actual" capital spending over the same three-year period.

[19] The Utilities are proposing a four-year term (2019-2022) for the TY 2019 GRC cycle, which would result in the next test year to be 2023. See the direct testimony of Post-Test Year Ratemaking witnesses Jawaad Malik (Ex. SCG-44) and Kenneth Deremer (Ex. SDG&E-43).

[20] D.16-06-054 at OP 11.

[21] The applications of SDG&E and SoCalGas for the 2012 GRC cycle were A.10-12-005 and A.10-12-006, respectively.

[22] The applications of SDG&E and SoCalGas for the 2016 GRC cycle were A.14-11-003 and A.14-11-004, respectively.

Further, the Utilities are presenting the non-balanced projects and metrics herein on a direct basis, which is the input into the revenue requirement, but not the revenue requirement itself, which is authorized in a GRC decision. By contrast, the balanced programs in this report (*i.e.*, TIMP, DIMP and SIMP) are presented on a revenue requirement basis, because the Utilities report on and manage to the authorized revenue requirement levels, not the direct spending.

c. Derivation of Authorized Dollars

For the majority of the "risk mitigation" projects covered in this report, the "authorized" amounts are discrete authorized funding values for those projects.[23] However, the Commission did not provide an authorized amount for SDG&E Dig-In-related activities. Therefore, the Utilities imputed the authorized values by using the amounts authorized in the Locate and Mark workpaper and adding Dig-In-related Public Awareness costs (*e.g.*, 811 Dig Alert Campaign).

For non-balanced spending in this report, O&M expenditures in 2014 and 2015 were authorized in the TY 2012 GRC, whereas the 2016 O&M spending was authorized in the TY 2016 GRC. However, the non-balanced capital spending for 2014, 2015, and 2016 was derived from the TY 2016 GRC, which includes approved capital projects in the forecast years (2014-2016) in the 2016 revenue requirement. The reason the Utilities used the "authorized" capital projects and activities from the TY 2016 GRC rather than the amounts from the TY 2012 GRC is because the projects required in this report in accordance with the TY 2016 GRC decision were not necessarily included in the TY 2012 GRC. For purposes of this report, the Utilities have presented the non-balanced information in direct nominal dollars (*i.e.*, the 2014, 2015, and 2016 authorized are in the 2014, 2015, and 2016 dollars, respectively).

To better illustrate this, consider the following example. In the TY 2012 GRC, specific capital forecasts were approved for years 2010-2012 to establish the revenue requirement for TY 2012. After the test year revenue requirement has been established, the revenue requirement going forward into the post-test years is based on an approved post-test year mechanism (usually an escalation factor), which gets applied to the total revenue requirement from the test year. Because the post-test year increase is based on a total revenue requirement instead of specific projects, the specific capital details in the post-test years for the TY 2012 GRC cycle are not available. In order to get specific capital details for 2014, 2015, and 2016, the Utilities had to use the forecast years from the TY 2016 GRC.

For the balanced programs, this report presents O&M and capital in revenue requirement terms because the programs are tracked on a revenue requirement basis, as required by the annual advice letter filings. Reviewing balanced programs in these terms, rather than in nominal direct dollars, reflects more accurately how the Utilities manage these programs and track costs. The purpose of managing to a revenue requirement is so that the Utilities stay within the authorized revenue requirement for the entire GRC cycle. While capital spend and the timing of capital becoming rate base are building blocks in creating an authorized revenue requirement, it is the authorized revenue requirement itself that utilities are measured against financially. Further,

[23] The Commission-approved final GRC decisions do not always provide authorized figures by project or activity, which may be needed for accountability reporting.

GRCs establish and authorize test year revenue requirements and apply an attrition year mechanism or escalator to build test year revenue requirements (please see Table 1, which illustrates this concept).

Table 1: Illustrative Example Timing of Capital

	Test year	Attrition Year 1***	Attrition Year 2***
Authorized Revenue Requirement	$21	$22	$23
Authorized Capital Costs			
a. Depreciation at 10 years (10%)	$10	$11	$11
b. Return (8%)	$8	$8	$9
c. Taxes (apprx. 40% of Return)	$3	$3	$4
Total Capital Costs	$21	$22	$23
Forecast Capital Spend	$100		
Implied Attrition allowed spend*		$15	$16
Forecasted Ratebase**	$100	$105	$110

* In attrition years, a utility can spend what has been depreciated in prior years plus a small amount equal to what would add up to the capital costs equal to the increase in revenue due to attrition.

**Assumes 100% weighting, January 1 close date. Reduces each year by depreciation and increases by capital spend.

*** For simplicity, assumes 5% attrition

Based on the foregoing, this report shows the balanced programs on a revenue requirements basis.

In summary, Tables 2 and 3 below present the projects in the scope of this report, whether the projects include O&M and/or capital, and how this information is presented herein.

Table 2: Derivation of 2014 and 2015 Authorized[24]

		Data Source		
	Projects	O&M	Capital	Presentation
	SDG&E Electric Operations	n/a	TY 2016 GRC	Nominal, Direct Dollars
	SDG&E Dig-Ins	TY 2012 GRC	TY 2016 GRC	Nominal, Direct Dollars
Balanced Programs	SoCalGas & SDG&E DIMP	TY 2012 GRC	TY 2012 GRC	Revenue Requirement
Balanced Programs	SoCalGas TIMP	TY 2012 GRC	TY 2012 GRC	Revenue Requirement
Balanced Programs	SoCalGas SIMP	n/a	n/a	Revenue Requirement

Table 3: Derivation of 2016 Authorized[25]

		Data Source		
	Projects	O&M	Capital	Presentation
	SDG&E Electric Operations	n/a	TY 2016 GRC	Nominal, Direct Dollars
	SDG&E Dig-Ins	TY 2016 GRC	TY 2016 GRC	Nominal, Direct Dollars
Balanced Programs	SoCalGas & SDG&E DIMP	TY 2016 GRC	TY 2016 GRC	Revenue Requirement
Balanced Programs	SoCalGas TIMP	TY 2016 GRC	TY 2016 GRC	Revenue Requirement
Balanced Programs	SoCalGas SIMP	TY 2016 GRC	TY 2016 GRC	Revenue Requirement

24 Authorized amounts for SDG&E Associated Overhead and SDG&E Dig-In Damage Prevention Program were imputed using a portion of the applicable workpaper group based on subject matter expert judgment.

25 Authorized amounts for SDG&E Associated Overhead and SDG&E Dig-In Damage Prevention Program were imputed using a portion of the applicable workpaper group based on subject matter expert judgment.

d. Derivation of Safety Performance Metrics for Risk Mitigation Benefits

Pursuant to D.16-06-054, the Utilities are proposing a methodology herein to satisfy the requirement of "how SDG&E and SoCalGas can report and compare projected versus actual benefits of their risk mitigation activities. The methodology should include relevant performance metrics…"[26] The Utilities' proposed methodology for risk mitigation benefits is based on performance metrics discussed in the S-MAP as well as the metrics referenced in D.16-06-054. D.16-08-016 supports using metrics to evaluate performance/benefits stating "[o]ne method for analyzing the risk mitigation accountability report may be to track the performance metrics developed by the working group to assess the safety performance of the utilities over time."[27]

For metrics mentioned in D.16-06-054, this report presents actual and planned activity levels. Generally, the planned levels represent what the Utilities put forth, or "proposed," in their direct testimony and workpapers from the TY 2016 GRC, which may be the underlying methodology or assumptions used to derive the Utilities' GRC forecasts. In other words, the "planned" metrics are the planning or forecasting assumptions of SoCalGas and SDG&E. This means that the planned metrics are not reflective of either the final GRC decision or the adopted settlement. The basis for using planned rather than "authorized" metrics is that the final GRC decisions and applicable settlement did not necessarily provide authorized metrics. Further, if no "planned" column is included in the metrics table, this indicates that the Utilities did not propose or include a metric when deriving their original GRC forecasts. For example, the Utilities do not forecast that dig-ins or fire ignitions will occur in a given year.

For metrics discussed in the S-MAP, the Utilities have been actively participating in the working group on reporting metrics established in Phase 1 of the S-MAP. The purpose of the S-MAP metrics working group is "to develop a set of performance metrics to use as a baseline in the proceeding."[28] The Utilities utilized the thought processes and work accomplished during Phase 1 of the S-MAP for these interim accountability reports by incorporating some of the performance metrics herein. Examples of these metrics include Transmission and Distribution Wires Down (Electric Operations), Total Damages (Third Party Dig-Ins) and In-Line Inspections (TIMP).

According to SED, "the working group has made strong progress and has reached the stage of refining a comprehensive and detailed set of performance metrics to offer in Phase Two of the first S-MAP."[29] Because Phase 2 of the S-MAP is currently underway, the metrics presented herein should be considered preliminary and subject to change. While the Utilities have discussed the presented metrics with Commission staff, open discussions with parties and SED continue in the metrics working group. Further, a final decision in the S-MAP Phase 2 proceeding may affect final metrics reported and tracked. As such, it is premature at this time to

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[26] D.16-06-054 at 39.

[27] D.16-06-018 at 159.

[28] *Id*. at 159-160.

[29] *Id.* at 158.

include all the metrics being discussed in the on-going S-MAP proceeding in these reports. Nonetheless, the Utilities have included in this report certain metrics in each of the sections below to measure safety performance over time.

The table below summarizes the metrics being provided in this report:

Projects	Metric	Origin
SDG&E Electric Operations	Component Replacement/Maintenance Programs – circuit breakers, capacitors, SF6 switches, underground switches, associated overhead	Metric and associated dollars ordered for inclusion in D.16-06-054 The planned metrics are the original planning assumptions for the associated forecasts.
	Metrics – vegetation inspections, data on hardware failures, equipment failures and wire failures	Included as described in D.16-06-054
	Fire ignitions, transmission & distribution wires down	Proposed metric in the S-MAP
	All other metrics	Included for measurement purposes
SDG&E Dig-Ins	Damages per 1,000 tickets	Proposed metric in the S-MAP
	All other data	Included for measurement purposes
SDG&E/SoCalGas DIMP	Aldyl-A replacements (SDG&E only)	Ordered for inclusion in D.16-06-054. The planned metrics are the original planning assumptions for the associated forecasts.
	All other metrics	Included for measurement purposes
SoCalGas TIMP	Total miles of high-pressure pipe inspected by in-line inspection	Proposed metric in the S-MAP
	All other metrics	Included for measurement purposes
SoCalGas SIMP	Wells inspected using an enhanced inspection protocol	Proposed metric in the S-MAP
	All other metrics	Included for measurement purposes

2. SDG&E Electric Operations – Wildfire Risk Projects and Electric Service Disruptions

In the TY 2016 GRC, SDG&E proposed various capital projects in the direct testimony of its Electric Distribution Capital witness that were categorized under "Safety and Risk Management."[30] Although these projects were characterized as safety and risk management projects in testimony, it should be noted that the testimony was written prior to issuance of D.14-12-025, which established the RAMP process, and prior to development of SDG&E's RAMP Report. Thus, only some of these projects are consistent with mitigation activities identified in SDG&E's RAMP Report. The TY 2016 GRC testimony's "Safety and Risk Management" categorization, which predated the now-established RAMP process, should not be mistaken as implying that all of these projects address SDG&E's top risks.

Similarly, these "Safety and Risk Management" projects were identified in the SED Staff Report (presented as Exhibit 23 in A.14-11-003/-004) and in the final decision, D.16-06-054 (p. 39), as "part of [SDG&E's] wildfire mitigation program." However, this assertion is incorrect, as not all of the projects address the wildfire risk. Projects that do not address wildfire risk are included separately below, in compliance with D.16-06-054.

The identified projects that are a part of SDG&E's wildfire mitigation program were described in testimony as follows:

> <u>SDG&E Weather Instrumentation Install (Budget Code 11243)</u>: This project is described as a collaborative effort with the National Weather Service, CAL FIRE [California Department of Forestry and Fire Protection], UCLA [University of California, Los Angeles], and the U.S. Forest Service included the procurement of two Atmospheric Profilers intended to increase SDG&E's understanding of Santa Ana winds. This project supports the goals of safety and reliability by developing a tool to mitigate risks associated with extreme fire potential during Santa Ana Winds with a vision to provide a decision support tool to fire agencies and the general public to increase public safety and overall preparedness.
>
> <u>Circuit 1215 Fire Risk Mitigation Project (Budget Code 12265):</u> This project replaces aged overhead conductor with new conductor, and replace wood poles with steel poles to enhance circuit reliability. The new facilities are designed using known local conditions as the basis for design; which, in the case of this circuit, includes extreme wind conditions. Re-conductoring wood to steel is intended to greatly reduce the risk of brush fires during high wind events in areas on Circuit 1215 known to have past wire-down events, and improve circuit reliability with the re-conductor.

[30] A.14-11-003, Ex. 134 SDG&E/Jenkins at 118-132.

Fire Risk Mitigation (FiRM) Phases 1 & 2 (Budget Code 13247) and FiRM Phase 3 (Budget Code 14247): FiRM is described as a program designed to aggressively address "fire risk by hardening critical areas by replacing antiquated line elements, utilizing advanced technology, and safeguarding facilities from known local weather conditions. FiRM is being broken into multiple phases, with the scope of work varying within each phase."[31] As FiRM began to ramp up and become a part of SDG&E's day-to-day operations, the phased approach of the program evolved into a single comprehensive program. The phased approach prioritized work based on location. SDG&E now prioritizes work based on information from the Reliability Improvements in Rural Areas Team (RIRAT)[32] and a probabilistic model, the Wildfire Risk Reduction Model (WRRM). SDG&E uses these "smarter" tools to replace its high-risk assets (*i.e.*, those that are likely more prone to failure and ignition) first rather than using location as the main criteria. This development is reflected in the descriptions and cost report tables below.

As presented in the TY 2016 GRC, FiRM consisted of three location-based phases with work planned through 2018. Phase 1 planned to address 7,200 poles that fall in the highest risk areas and was anticipated to take place between 2014 and 2015. Phase 2 of FiRM was planned to address the remaining 30,000 poles in the High-Risk Area and was planned to take place between 2014 and 2018. The activities for Phase 2 included targeted re-conductoring and hardening, based on history, known local conditions, and pole load information. Phase 3 of FiRM was planned to address the remaining poles in the Fire Threat Zone (approximately 40,000 poles). For this phase, the distribution facilities were intended to be LiDAR surveyed (Light Detection and Ranging) and PLS-CADD models will be developed for analysis.

Circuit 441 Pole Loading Study/Fire Risk Mitigation (Budget Code 13255): This project replaces 1.5 miles of aged overhead conductor with new conductor, and replaces wood poles with steel poles to enhance circuit reliability. The new facilities are designed using known local conditions as the basis for design, which for this circuit includes extreme wind conditions. This particular circuit is located in mountainous areas vulnerable to extreme winds and other storm events, which have resulted in outages related to fallen trees/branches, debris blowing into the energized conductors, wire-to-wire contact, and equipment failure.

Distribution Aerial Marking and Lighting (Budget Code 13266): The primary objective of this budget is to comply with FAA [Federal Aviation Administration] requirements, California State Aeronautics Code Title 21, and local Airport Land Use Commissions, in addition to increasing public and employee safety by installing aerial marking and

[31] *Id*. at 123:21-23.

[32] RIRAT is a multi-disciplinary technical team of subject matter experts within SDG&E that "focuses its attention on facilities and activities in these areas so as to assure that all prudent and cost-effective fire-prevention measures are promptly evaluated and implemented." *Id*. at 7:11-13.

lighting. The alternative to this project is just merely complying with FAA regulations, but that does not address all areas where there is a risk of aviation collision with overhead electric facilities.

Cleveland National Forest (CNF) (Budget Code 13282): This budget is required as part of a legal agreement with the CNF to replace aging overhead infrastructure with new overhead and underground facilities. As part of the renewal of our Master Special Use Permit with CNF, SDG&E agreed to rebuild overhead power lines by replacing them with new overhead and underground facilities.

The projects described below were not specifically intended to address SDG&E's fire risk, but were identified as "Safety and Risk Management" projects in SDG&E's TY 2016 GRC testimony. Reporting on these projects is provided in compliance with D.16-06-054.

Replace for Live Front Equipment (Budget Code 6247): Live front replacement is an ongoing secondary capital project that replaces live front equipment with dead front pad-mounted equipment[33] in conjunction with other SDG&E work (*e.g.*, cable replacement, circuit upgrades, etc.). Live front equipment was primarily installed on SDG&E's electric distribution system during the 1960's and 1970's, and has since become obsolete, being replaced by 'dead-front' equipment, which has additional safety barriers such as removable fiberglass or composite plates, protective covers or additional compartmentalization.

PowerworkZ (Budget Code 12256): The Powerworkz project is a one-time acquisition of three off-the-shelf software systems used for customized vegetation management purposes: a widely used Geographical Information System (GIS) platform, a mobile GIS solution, and asset management program.

Sulfur Hexafluoride (SF6) Switch Replacement (Budget Code 14249): The SF6 Switch Replacement is a project to remove or replace SF6 gas insulated distribution switchgear, to reduce environmental risks associated with the potential for SF6 emissions. Because SF6 emissions are known to have a global warming potential, leaking SF6 switches are subject to the federal Climate Action Plan goal (Environmental Protection Agency) and state (California Air Resources Board) AB 32 California Global Warming Solutions Act of 2006. AB 32 mandated efforts are expected to reduce greenhouse gas emissions to 1990 levels by 2020. The costs of the project were allocated over five years and projected to remove or replace switches beginning in 2016.

For the electric distribution capital projects identified for reporting in D.16-06-054, pages 39-40, the tables below show cost comparisons between actual and authorized amounts for the years 2014, 2015, and 2016, with explanations for the variances provided below each table.

[33] Live front electric distribution equipment is defined by having their primary connections exposed with no insulated covering. Thus, when the equipment is opened, there are energized, or "live," conductors present. By contrast, dead front equipment is where the energized primary conductors are insulated from contact.

Comparison of 2014 and 2015 Authorized Spending to 2014 and 2015 Actual Spending[34]

Capital Project	2014 Actuals	2014 Authorized	2014 Variance
	Nominal Dollars ($000)		
SDG&E Weather Instrumentation Install (BC 11243)	$494	$426	$68
Circuit 1215 Fire Risk Mitigation Project (BC 12265)	$59	$61	($2)
FiRM Phases 1, 2, & 3 (BC 13247 & 14247)	$16,729	$18,209	($1,480)
Circuit 441 Pole Loading Study/Fire Risk Mitigation (BC 13255)	$83	$83	($0)
Distribution Aerial Marking and Lighting (BC 13266)	$0	$0	$0
Cleveland National Forest (CNF) (BC 13282 & 081650)	$88	$112	($24)
Sub-Total Fire Specific	**$17,453**	**$18,891**	**($1,438)**
Replace for Live Front Equipment (BC 6247)	$389	$394	($5)
Powerworkz (BC 12256)	$605	$610	($5)
SF6 Switch Replacement (BC 14249)	$0	$0	$0
Sub-Total Other TY2016 Elect Dist Safety & Risk Projects	**$994**	**$1,004**	**($10)**
Total TY2016 GRC Elect Dist Safety & Risk Projects	**$18,447**	**$19,895**	**($1,448)**

2014 Variance Explanation:

In SDG&E's TY 2016 GRC Settlement Comparison Exhibit, the 2014 authorized amounts were based upon the 2014 actual expenditures represented in 2013 constant dollars, with the exception of FiRM Phases 1 & 2. For FiRM Phases 1 & 2, the settlement was $1.2M higher than actual incurred expenses. All other variances between 2014 actuals and 2014 authorized are due to escalation calculation differences.

	2014				
	Metrics		Nominal Dollars ($000)		
Component Replacement & Maintenance Programs:	Actual Replacement Rate	Planned Replacement Rate	Actual Expense	Authorized Expense	Variance
Circuit Breakers (BC 992820)	34	4	$282	$284	($2)
Capacitors (BC 112490, 002090, 082530)	39	17	($980)	($1,771)	$791
SF6 Switches (BC 14249A & 142490)	0	0	$0	$0	$0
Underground Switches (BC 002890)	38	40	$5,416	$5,476	($60)
Associated Overhead (portions of BC 009010, 009040, 009050, 00906A, & 009060)	n/a	n/a	$2,702	$1,256	$1,446

[34] The Cleveland National Forest project has been updated for years 2014 and 2015 to also include Actuals and Authorized from budget code 081650 that were previously omitted in error. BC 13282 was included in the TY 2016 GRC for the Cleveland National Forecast project under the Safety and Risk group of budget codes; however, when the Cleveland National Forecast project was implemented, all segments of the project are recorded to BC 081650. BC 081650 was originally authorized in the TY 2016 GRC as the CPUC jurisdiction portion of the Transmission/FERC Line Replacement.

2014 Variance Explanations:

Circuit Breakers – For purposes of clarifying the information being provided, SDG&E notes that it is reporting a higher replacement rate here than was provided in response to a data request from CCUE during the TY 2016 GRC. In that data request response, SDG&E only included planned replacements for circuit breakers on blanket substation reliability and capacity budgets. The replacement rate reported here also includes breakers being replaced on specific capital budgets such as the Cannon, Sunnyside, and Los Coches Rebuilds. Additionally, SDG&E reports that there are circuit breaker replacement costs contained within other budget codes that cannot be separated from new installations and are not included in the actual dollars being reported on this line.

Capacitors[35] – Capacitors are recorded to multiple budget codes. The actual type of capacitors installed differed from what was forecasted in the TY 2016 GRC and the average cost to install the capacitors varied accordingly. As an example, the forecasted level of Supervisory Control and Data Acquisition (SCADA) capacitors in the TY 2016 GRC was lower than actually installed in 2014. The credit in the actual spend was due to materials reconciliation between projects from previous years.

Overhead - variances associated with component replacement and maintenance programs are primarily driven by changes in capital expenditure results.

Capital Project	2015 Actuals	2015 Authorized	2015 Variance
	Nominal Dollars ($000)		
SDG&E Weather Instrumentation Install (BC 11243)	($29)		($29)
Circuit 1215 Fire Risk Mitigation Project (BC 12265)			$0
FiRM Phases 1, 2, & 3 (BC 13247 & 14247)	$52,170	$38,950	$13,220
Circuit 441 Pole Loading Study/Fire Risk Mitigation (BC 13255)			$0
Distribution Aerial Marking and Lighting (BC 13266)	$0	$147	($147)
Cleveland National Forest (CNF) (BC 13282 & 081650)	$929	$7,221	($6,292)
Sub-Total Fire Specific	**$53,070**	**$46,318**	**$6,752**
Replace for Live Front Equipment (BC 6247)	$414	$885	($471)
Powerworkz (BC 12256)	($1)		($1)
SF6 Switch Replacement (BC 14249)			$0
Sub-Total Other TY2016 Elect Dist Safety & Risk Projects	**$414**	**$885**	**($471)**
Total TY2016 GRC Elect Dist Safety & Risk Projects	**$53,483**	**$47,203**	**$6,280**

35 At the request of OSA, at the conclusion of our meeting on August 29, 2017, we have updated the Component Replacement & Maintenance Program tables to include the applicable budget codes that are being included. Additionally, the Proposed Capacitor numbers have been updated to include the capacitors that were requested by BC 082530 at 11 per year. Actual capacitors have also been updated.

2015 Variance Explanations:

FiRM Phases 1, 2 & 3 - variance totals $13.2M and is mainly driven by a ramp-up in construction activities during 2015.

Cleveland National Forest - variance is due to delayed approval of Permit to Construct (PTC). SDG&E received the PTC from the Commission in D.16-05-038, dated May 26, 2016, which resulted in subsequent construction starting in September 2016.

Replace for Live Front Equipment - this a secondary project is used when live front equipment is replaced in conjunction with other capital work (*e.g.*, cable replacement, circuit upgrades, etc.). The variance in completion of live front replacement is dependent on circumstances, such as where projects are being completed and whether those areas have live front equipment that needs to be replaced).

	2015				
	Metrics		Nominal Dollars ($000)		
Component Replacement & Maintenance Programs:	Actual Replacement Rate	Planned Replacement Rate	Actual Expense	Authorized Expense	Variance
Circuit Breakers (BC 992820)	18	7	$0	$685	($685)
Capacitors (BC 112490, 002090, 082530)	18	17	($106)	$4,049	($4,155)
SF6 Switches (BC 14249A & 142490)	0	0	$0	$0	$0
Underground Switches (BC 002890)	48	60	$5,519	$7,874	($2,355)
Associated Overhead (portions of BC 009010, 009040, 009050, 00906A, & 009060)	n/a	n/a	$1,967	$7,455	($5,488)

2015 Variance Explanations:

Circuit Breakers – For purposes of clarifying the information being provided, SDG&E notes that this budget code is intended for Replacement of Obsolete Substation Equipment work of which Circuit Breakers are only a small portion. The actual replacement rate reported here also includes breakers being replaced on specific capital budgets such as the Cannon, Sunnyside, and Los Coches Rebuilds. Additionally, SDG&E reports that there are circuit breaker replacement costs contained within other budget codes that cannot be separated from new installations, and are not included in the actual dollars being reported on this line. *Note: The authorized and actual dollar values for circuit breaker replacements have been updated since the First Interim Report, which reported on all costs in the Replacement of Obsolete Equipment budget code, instead of reporting only on the circuit breaker component. The authorized dollars in the Second Interim Report include only the circuit breaker component. In addition, the actual expenses recorded on this budget code did not include any circuit breaker work, so that value has been changed to zero.*

Capacitors[36] – Capacitors are recorded to multiple budget codes. The actual type of capacitors installed differed from what was forecasted in the TY 2016 GRC and the average cost to install

[36] At the request of OSA at the conclusion of our meeting on August 29, 2017 we have updated the Component Replacement & Maintenance Program tables to include the applicable budget codes that are

the capacitors varied accordingly. As an example, the forecasted level of SCADA capacitors in the TY 2016 GRC was lower than actually installed in 2015. The credit in the actual spend was due to materials reconciliation between projects from previous years.

Underground Switches – The Do Not Operate Energized (DOE) switch replacement variance was due to a number of issues. Each switch replacement job is unique and will have different variables with land rights, environmental impacts and customer impacts. Some jobs had permit delays with the cities or municipalities, some had outage coordination issues with customers, and others were delayed by equipment availability from the manufacturer. Additionally, the original estimate for underground switches was based on two types of replacements, replacements with manual switches and replacements with SCADA switches. SCADA switches provide data for improved operator situational awareness, system planning load studies, and provide for remote and automated control operation, allowing for improved restoration response and reliability, but are more costly than manual switches for both materials and labor. The reality was that many of the DOE switch locations were not good fits for SCADA, so manual switches were designed and replaced at a proportionately higher rate than was assumed in the estimate. SDG&E is continuously improving strategies to work through the issues noted, to have more consistent switch replacement schedules from job to job. The lower cost of manual switch replacement leads to a portion of the overall budget underrun. *Note: The authorized and actual dollar values for DOE switch replacement have been updated since the First Interim Report. The First Interim Report reported on all costs contained in the CMP UG Switch Replacement and Manhole Repair budget code, of which underground switch replacement is only one component. Authorized dollars in this report include only the underground switch component. In addition, the actual expenses recorded on this budget code have also been updated to remove other work (such as overhead switch replacement and underground structures work) that is also included in this budget code.*

Overhead – variances associated with component replacement & maintenance programs are primarily driven by changes in capital expenditure.

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being included. Additionally, the Proposed Capacitor numbers have been updated to include the capacitors that were requested by BC 082530 at 11 per year. Actual capacitors have also been updated.

Comparison of 2016 Authorized Spending to 2016 Actual Spending

Capital Project	2016 Actuals	2016 Authorized	2016 Variance
	Nominal Dollars ($000)		
SDG&E Weather Instrumentation Install (BC 11243)			$0
Circuit 1215 Fire Risk Mitigation Project (BC 12265)			$0
FiRM Phases 1, 2, & 3 (BC 13247 & 14247)	$54,134	$61,714	($7,580)
Circuit 441 Pole Loading Study/Fire Risk Mitigation (BC 13255)			$0
Distribution Aerial Marking and Lighting (BC 13266)	$6	$150	($144)
Cleveland National Forest (CNF) (BC 13282 & 081650)	$8,976	$11,451	($2,475)
Sub-Total Fire Specific	**$63,116**	**$73,315**	**($10,199)**
Replace for Live Front Equipment (BC 6247)	$515	$906	($391)
Powerworkz (BC 12256)	($1)		($1)
SF6 Switch Replacement (BC 14249)	$459	$10,623	($10,164)
Sub-Total Other TY2016 Elect Dist Safety & Risk Projects	**$973**	**$11,529**	**($10,556)**
Total TY2016 GRC Elect Dist Safety & Risk Projects	**$64,089**	**$84,844**	**($20,755)**

2016 Variance Explanations:

FiRM Phases 1, 2 & 3 - The 2016 FiRM variance is primarily related to phasing of construction activities; the GRC filing assumed steep increases between 2014-2016, while actual work activities peaked in mid-2015 and remained stable thereafter.

Distribution Aerial Marking and Lighting – This project has a similar version on the transmission side, Transmission Aerial Marking and Lighting. The majority of marking and lighting work will be completed on the transmission side as their structures are more likely to exceed the criteria for their need. The cost to install the aviation obstruction marking and lighting varies, ranging from five thousand up to seventy-five thousand dollars. Costs vary depending on whether lights or markers are used, the number of lights or markers and the complexity of the work. The number of jobs to be done per year is indeterminate, as SDG&E cannot foresee where the FAA or local Airports will determine installation of markers or lighting is required. The original forecast was based on four projects per year whereas only one project was needed in 2016.

Cleveland National Forest – The variance is due to delayed approval of PTC. SDG&E received the PTC from the Commission in D.16-05-038, dated May 26, 2016, which resulted in subsequent construction started in September 2016.

Replace for Live Front Equipment – as explained above, the Replace for Live Front Equipment project is a secondary project, which is used when live front equipment is replaced in conjunction with other capital work (*e.g.*, cable replacement, circuit upgrades, etc.). The variance in completion of live front replacement is dependent on circumstances, such as where projects are being completed and whether those areas have live front equipment that needs to be replaced.

SF6 Switch Replacement – To avoid duplication, since this project shows up in two places, please see the complete explanation below.

	2016				
	Metrics		Nominal Dollars ($000)		
Component Replacement & Maintenance Programs:	Actual Replacement Rate	Planned Replacement Rate	Actual Expense	Authorized Expense	Variance
Circuit Breakers (BC 992820)	31	8	$0	$755	($755)
Capacitors (BC 112490, 002090, 082530, 13288A)	11	18	$652	$4,166	($3,514)
SF6 Switches (BC 14249A & 142490)	4	200	$459	$10,623	($10,164)
Underground Switches (BC 002890)	53	60	$5,527	$8,057	($2,530)
Associated Overhead (portions of BC 009010, 009040, 009050, 00906A, & 009060)	n/a	n/a	$2,515	$10,251	($7,736)

2016 Variance Explanations:

The "planned" replacement rates were planning or forecasting assumptions SDG&E used to derive the TY 2016 GRC forecasts. The "planned" values were not intended to be used as metrics for accountability reporting purposes. SDG&E is providing these replacement rates and the associated dollars in accordance with D.16-06-054.

Circuit Breakers – For purposes of clarifying the information being provided, SDG&E notes that this budget code is intended for Replacement of Obsolete Substation Equipment work, of which Circuit Breakers are only a small portion. For the replacement rate levels listed under "Metrics" in the table above, the Actual Replacement Rate includes both planned replacements for circuit breakers on blanket substation reliability and capacity budgets (*i.e.*, a routine circuit breaker replacement project) as well as circuit breakers being replaced on specific capital budgets or projects (*e.g.*, substation rebuilds such as the Los Coches Rebuild). Conversely, the Planned Replacement Rates as well as the Authorized Expense represent only the blanket or routine circuit breaker portion of this budget code. SDG&E wanted to show all the circuit breakers that were indeed replaced in 2016. However, for specific capital projects, SDG&E cannot isolate circuit breakers contained within specific capital projects or other budget codes. For example, if SDG&E has a project for a substation rebuild, it does not separately forecast or financially track the circuit breaker within the larger substation rebuild. Rather, SDG&E forecasts and tracks the entire capital project costs. As such, the actual dollars being reported in this report is not inclusive of all circuit breaker costs. No circuit breakers were replaced under this budget code during 2016; the dollar variance is a result of actual circuit breakers being replaced on other budget codes, however, and are not included in the Actual Expense column.

Capacitors – Capacitors are recorded to multiple budget codes. The actual type of capacitors installed differed from what was forecasted in the TY 2016 GRC and the average cost to install the capacitors varied accordingly. As an example, the forecasted level of SCADA capacitors in the TY 2016 GRC was lower than actually installed in 2016. The actual spend was lower than authorized due to materials reconciliation where capacitor expenses recorded in prior years were transferred to the jobs that actually utilized them.

SF6 Switch Replacement – This project was forecasted in the TY 2016 GRC to begin replacing 200 switches per year beginning in 2016. Only 4 switch replacements were completed in 2016. The SF6 program encountered several difficulties in ramping up to the forecasted high-volume replacements of 200 per year. First, SDG&E's engineering team decided that a full system assessment was required to truly understand how many SF6 units were in service, the actual locations of the equipment, and the condition of these devices prior to commencing SF6 replacements. With that information, a true analytical approach could be applied to first remove all known "leakers," followed by units that would have the greatest benefit to system operations, reliability, and overall worker safety. Second, during 2016, there were also several issues with SDG&E's main manufacturer. These issues ranged from internal management conflicts to labor issues with their sheet metal workers. These issues greatly impacted their ability to fulfill their standard switch orders for all their utility customers for nearly a 2-year period. Engineering worked with a new organization, that was just beginning operations, to duplicate similar products for the entire product line (~ 20 different switches and associated form factors). Now, SDG&E has two manufacturers to fulfill the materials orders. Third, the replacement switches are very complicated and customized designs; off the shelf products are not readily available for purchase without going to larger footprint units that would impact design/construction/permitting due requiring more space, since they have a larger physical footprint. Fourth, these switches are often in very challenging environments when located underground where facilities may routinely be submerged in water after storms. Fifth, the existing manufacturers' production lines typically run at 100%+ capacity due to the expertise and time required to construct these units, which have several long lead time components. Manufacturers are required to expand their existing operations to meet projected order quantities. Other technologies such as oil, air, and solid-dielectric medium switches have a larger foot print and usually require an increase in easement and franchise, resulting in approval delays in permitting due to right of way issues. One of the main benefits of a SF6 switch is the small physical foot print that allows maintaining designs within current franchise and easements. Additionally, the Americans with Disabilities Act's (ADA) increased requirements of 48" for sidewalks brought additional challenges to SF6 equipment replacements that were already installed according to the previous 36" requirement. Lastly, these additional sources as well as getting the initial manufacturer back to normal operations were critical in order to match the expected volumes required to meet the objectives of this project. With a full system assessment now completed, a prioritization list identified, and with existing vendors ramping production schedules, SDG&E expects that all known units that are exhibiting pressure losses will be eliminated before the 2020 mandate. This project will require five years or more to truly achieve the goal to eliminate all SF6 products from the distribution network. Nonetheless, SDG&E is committed to removing or replacing the SF6 switches and its focus is working, over the following few years, to eliminate/replace all remaining facilities.

Underground Switches – SDG&E forecasted that it would replace 60 DOE switches in 2016. The DOE switch replacement variance was due to a number of issues. Each switch replacement job is unique and will have different variables with land rights, environmental impacts and customer impacts. Some jobs had permit delays with the cities or municipalities, some had outage coordination issues with customers, and others were delayed by equipment availability from the manufacturer. Additionally, the original estimate for underground switches was based on two types of replacements, replacements with manual switches and replacements with SCADA switches. SCADA switches provide data for improved operator situational awareness, system planning load studies, and provide for remote and automated control operation, allowing for improved restoration response and reliability, but are more costly than manual switches for both materials and labor. The reality was that many of the DOE switch locations were not good fits for SCADA, so manual switches were designed and replaced at a proportionately higher rate than was assumed in the estimate. SDG&E is continuously improving strategies to work through the issues noted, to have more consistent switch replacement schedules from job to job. The lower cost of manual switch replacement leads to a portion of the overall budget underrun. The authorized dollars only include the underground switch component replacement. In addition, the actual expenses recorded exclude the overhead switch replacement and underground structures work that are also included in this budget code.

Overhead – Overheads are dependent on the amount of capital work performed. As such, the variances associated with component replacement & maintenance programs identified herein are primarily driven by changes in capital expenditure.

SDG&E Electric Operations Metrics Levels[37]

SDG&E provides the proposed metrics below. Some of these metrics (such as Hardware and Equipment Failures) are being included pursuant to D.16-06-054, while others (such as Number of Fire Ignitions) are being provided for measurement purposes in these areas over time.

SDG&E Electric Operations Metrics	2014 Actuals	2015 Actuals	2016 Actuals
Completed Vegetation Inspections	484,293	480,240	478,927
Vegetation Related Outages	48	37	55
Hardware Failures	49	58	53
Other Equipment Failures	183	181	269
Total Equipment Failures	**232**	**239**	**322**
Wire Down due to Equipment Failure	17	10	15
Wire Down due to Other Causes	49	52	91
Total Wire Down (Transmission & Distribution)	**66**	**62**	**106**
Number of Fire Ignitions	30	32	30
Reliability Index - SAIDI (minutes of sustained outages per customer per year)	64.59	57.92	72.74
Reliability Index - SAIFI (number of sustained outages per customer per year)	0.603	0.526	0.620

[37] The Electric Operations Metrics, with the exception of the completed vegetation inspections and number of fire ignitions, excludes events related to outages excluded through the major event day (MED) criteria defined by IEEE 1366. This reporting is consistent with other reliability metrics such as SAIDI and SAIFI. The format and numbers have been updated since the First Interim Report accordingly.

Explanations for Year over Year Changes:

2016 Weather Overview – Following the drought-stricken winters of 2014 and 2015, strong El Nino conditions developed in 2015, which resulted in the return of significant winter storms to the SDG&E service territory during 2016 and impacted 2016 actuals. Overall, 2014 was a warm and dry year with well below normal rainfall and storm activity. By the end of 2014, San Diego had experienced three winter storm systems over a five-day period, which generated rainfall and wind gusts exceeding 30 mph across highly populated areas. The warm and dry conditions intensified into 2015, when SDG&E experienced the warmest and fourth-driest start to the year in history. There were no significant winter storm events through the first half of 2015. The development of strong El Nino conditions caused a return to near-normal storm events, with four storm events spanning six days in November and December. The increasing number of coastal storm events continued into 2016, and for the first time since the winter of 2010-2011, SDG&E experienced near-average winter storm activity. During 2016, SDG&E experienced five significant winter storm events spanning thirteen days.

Completed Vegetation Inspections – Inspection numbers do not include off-cycle inspections (*e.g.*, post-storm, post-fire, pre-fire season in highest risk fire areas and species-specific inspections). SDG&E physically inspects all spans of overhead line documenting and updating tree/vegetation that is contained within the PowerworkZ database on an annual basis. The SDG&E tree inventory is fluid, meaning that each year trees are removed, pruned, and added to the inventory. For these reasons, the number of trees in inventory will vary from year to year from 460,000 to 480,000. The SDG&E program removes incompatible trees and replaces them with trees that will not grow tall enough to become an inventory issue at its maturity. San Diego has a very diverse landscape where trees are continuously planted and removed by home owners and landscape businesses; therefore, this varying annual inventory is the main driver of the number of vegetation inspections completed each year.

Vegetation Related Outages – Vegetation Related Outages are outages of any duration that were caused by vegetation excluding vegetation caused outages on major event days. In 2016, SDG&E experienced an increase in vegetation caused outages due to severe coastal storms. These storms delivered high winds with heavy rain, and saturated soil. This resulted in several downed whole trees and large branch failures throughout the coastal areas of San Diego and Orange Counties. SDG&E also saw an increase in tree-caused outages from the private sector. SDG&E works hard to educate the private and local industry about the electrical hazards and risks of pruning and/or removing trees in proximity to overhead lines. SDG&E has a very aggressive tree trim and removal program that helps deliver reliable and safe services. *Note: The 2014 and 2015 vegetation-related outages have been updated since the First Interim Report. The First Interim Report reported on all vegetation-related outages; however, as described in footnote 37, MED have now been excluded. In addition, in 2015, daily system outage report coding changes were made to some outages, which are reflected here.*

Hardware Failures – Overhead system hardware failures include overhead connectors/jumpers, miscellaneous hardware, insulator/pin/wire floating and sub-hardware excluding failures during major event days. Hardware failures are a subset of total equipment failures. The year-over-year numbers are consistent with historical trends.

Other Equipment Failures – Overhead equipment failures include all overhead equipment categories within reliability (*e.g.*, transformers, switches, capacitors, substation equipment, poles, etc.). The increase in 2016 equipment failures reflects the increase in outages in the coastal regions (outside of the fire threat zone (FTZ)) due to storms and the corrosive coastal environment. SDG&E plans to address this issue in numerous programs discussed in the testimony of Alan Colton (Exhibit SDG&E-14) and William Speer (Exhibit SDG&E-15), such as the 4kV modernization program, the overhead switch inspection and replacement program, and the pole risk mitigation and engineering (PRiME) program.

Wire Down due to Equipment Failures – This category consists of transformers, switches, structures, and hardware, etc., failures leading to a wire down. The year over year numbers are consistent with historical trends.

Wire Down due to Other Causes – A wire-down event can also be caused a variety of external events or forces. Third-party external forces cause wire-down events, such as car-to-pole contact, contact from vegetation from outside of SDG&E's right of way, construction equipment, Mylar balloons, birds, etc., and this varies from year to year. Inclement weather events increase the number of wire-down events. In 2016, SDG&E experienced significant storms that caused an increase in wire-down events.

Number of Fire Ignitions[38] – D.14-02-015 requires SDG&E to report annually (on April 1) fires meeting the following criteria (*i.e.*, "reportable fires"):

- Electric in origin
- Leaves the electric facility
- Travels more than one meter from the electric facility
- Is self-propagating (meaning if the energy is turned off, the fire will still burn).

The number of reportable fires is staying relatively flat, largely due to fire hardening efforts and the vegetation management program.

Reliability Index – System Average Interruption Duration Index (SAIDI): SAIDI represents the number of *minutes* of sustained outages per customer per year and is measured as the distribution and transmission components with Threshold Major Event Days (TMED) excluded.

- 2015 system SAIDI was low as compared to 2016 due a reduced number of outages in the following categories (listed in descending order):
  - Distribution Equipment failures
  - Foreign object contacting distribution lines (bird and balloon)
  - Transmission and substation related outages
  - Wildfires
  - Weather related events

[38] The First Interim Report previously reported on fire ignitions solely due to wire-down incidents. In order to be consistent with D.14-02-015, this second report now reflects all reportable fires for 2014-2016.

- 2016 system SAIDI is higher than 2014 and 2015, largely due to an increase in connector failures in the underground systems and an increase in substation-caused outages.

Reliability Index – System Average Interruption Frequency Index (SAIFI): SAIFI represents the number of sustained *outages* per customer per year and is measured as the distribution and transmission components with TMED excluded.

- 2015 system SAIFI was low, largely due to the absence of major transmission and substation-related outages.
- 2016 system SAIFI is higher than 2014 and 2015, largely due to an increase in connector failures in the underground systems and an increase in substation-caused outages.

3. SDG&E Gas Operations – Gas Safety Incidents (Third-Party Dig-Ins and elements of DIMP including projects associated with replacing aging infrastructure)

a. Third-Party Dig-Ins

A third-party dig-in occurs when people or companies excavate in the vicinity of buried utility infrastructure without realizing the infrastructure is there or if proper excavation practices are not adhered to during the excavation.[39] These third parties can "dig-in" to the gas underground piping and facilities, which can cause catastrophic consequences. The primary mitigation activities in the Dig-In damage prevention program included in the Utilities' previous GRC cycles are Locate and Mark (including pipeline observation (stand-by) and the Damage Prevention Public Awareness Campaign.

As explained by SDG&E in its 2016 GRC testimony and in its RAMP Report, Locate and Mark is the process mandated by 49 Code of Federal Regulations (CFR) 192.614 (Damage Prevention Program) and the California One-Call Law (Government Code Section 4216), where the owner of underground facilities, when notified by the Underground Service Alert (USA) One-Call Center of a planned excavation, must respond within two working days and mark the location of those underground facilities that are in conflict with the planned excavations. To comply with the Locate and Mark regulatory and legal requirements, employees use an electronic pipe-locating device to identify the location of SDG&E's underground pipelines and utilize substructure maps and service history records to aid in verifying the location of the gas lines.[40] Conducting stand-by observations of other entities excavating in close proximity to SDG&E high priority pipelines is another important damage prevention activity. Generally, this involves an employee inspecting construction job sites to confirm that excavators are aware of the location of critical SDG&E gas facilities. The State of California enacted regulations in 2007 that mandate a preconstruction meeting with excavators requesting Locate and Mark support and require continuous monitoring of all excavations within ten feet of high-pressure pipelines.[41]

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[39] RAMP Chapter SDG&E-2, *Catastrophic Damage Involving Third Party Dig-Ins* (November 30, 2016) at SDGE 2-2.

[40] *Id*.

[41] *See* Cal. Code Regs., Tit. 8, § 1541(b)(1)(B) (2007).

The Public Awareness Campaign is mandated pursuant to Title 49 CFR 192.616. Its purpose is to develop and implement a continuous public education program focused on use of the One-Call notification system; hazards associated with the unintended release of gas; physical indications that an unintended release of gas has occurred; steps that should be taken to protect public safety in the event of gas release; and procedures for reporting unintended releases of gas. SDG&E utilizes multiple channels for this communication such as billboards, bill inserts, radio announcements, bumper stickers, safety events, press releases, social media, and sponsorships to capture a vast audience.[42]

The tables below represent the cost of dig-in prevention for years 2014-2016. As described below, the variance for 2014-2016 is due to the difference between the forecast methodology (in the case of Locate and Mark, a five-year average) and the recorded level. The volume of required Damage Prevention activities is typically driven by general construction activity in public and private rights-of-way and customer growth. These factors generally fluctuate with economic conditions, which means the exact amount of dig-in-related activities in any given year is uncertain when managing incurred costs.

The Actual and Authorized amounts in the tables below leverage the Locate and Mark workpaper group and add the Public Awareness Dig-In Campaign, which is a portion of a different workpaper. The 2014 and 2015 O&M values were taken from the TY 2012 GRC workpapers; the 2016 O&M and all capital amounts were taken from the TY 2016 GRC Settlement Agreement.

Comparison of 2014 and 2015 Authorized Spending to 2014 and 2015 Actual Spending

	2014 O&M Dollars			2014 Capital Dollars		
($000) Nominal Dollars	Actuals	Authorized	Variance	Actuals	Authorized	Variance
Total Cost of Dig-In Damage Prevention Program	$2,768	$2,647	$120	$216	$218	($2)

2014 Variance Explanations:

Locate and Mark costs fluctuate each year based on location, quantity, and complexity of jobs. As described in the narrative above because the volume of required Damage Prevention activities is typically driven by general construction activity in public and private rights-of-way and customer growth, which generally fluctuate with economic conditions, the exact amount of dig-in-related activities in a given year is uncertain when managing incurred costs.

	2015 O&M Dollars			2015 Capital Dollars		
($000) Nominal Dollars	Actuals	Authorized	Variance	Actuals	Authorized	Variance
Total Cost of Dig-In Damage Prevention Program	$2,658	$2,718	($61)	$282	$264	$19

2015 Variance Explanations:

[42] RAMP Chapter SDG&E-2, *Catastrophic Damage Involving Third Party Dig-Ins* (November 30, 2016) at SDGE 2-15.

The variance explanation for 2015 is the same as the 2014 variance explanation above.

Comparison of 2016 Authorized Spending to 2016 Actual Spending

	2016 O&M Dollars			2016 Capital Dollars		
($000) Nominal Dollars	Actuals	Authorized	Variance	Actuals	Authorized	Variance
Total Cost of Dig-In Damage Prevention Program	$3,059	$2,754	$304	$424	$316	$108

2016 Variance Explanations:

The variance explanation for 2016 is the same as the 2014 variance explanation above.

SDG&E Third-Party Dig-In Metrics Levels

	2014 Actuals	2015 Actuals	2016 Actuals
Number of 3rd Party damages to High Pressure Pipe	0	0	0
Number of 3rd Party damages to Medium Pressure Pipe	318	364	405
Total Damages	318	364	405
Total Locate & Mark Tickets [(1)]	106,129	115,340	123,726
Damages per 1,000 USA Tickets [(2)]	3.0	3.2	3.3

[(1)] The methodology for reporting "Total Locate & Mark Tickets" was modified in 2015 to report only "New" USA tickets intead of "All" types of tickets (New, renewal, job extensions, etc.). The 2015 Annaul DOT report shows 65,096 as the Total number of USA tickets which is only the number of "New" USA tickets experienced at SDG&E. The number included in the table above is the total of "All" USA tickets that would have been reported had the methodology not changed. This allows for apples-to-apples comparison of the values and for trending purposes.

[(2)] This is an industry wide metric used to evaluate Damage Prevention performance and routinely used on PHMSAs website when showing data and statistical information. The Calculation is (Total Damages / Total Tickets X 1,000)

Explanations for Year over Year Changes:

Although the number of damages and tickets have increased in each year, the rate of increase is slightly lower in 2016 (11%) than it was in 2015 (14%). The increase in the number of tickets can be attributable to an increase in construction/excavation activities and/or more contractors/excavators calling for tickets that might not have called in the past. Contractor/excavator awareness of the new requirements of the California Dig-Safe Law along with the focused efforts of SDG&E's Public Awareness Campaign could be increasing contractor/excavator awareness of the 811 Dig Alert service, which would increase the number of tickets.

b. SDG&E Distribution Integrity Management Program

SDG&E's DIMP is founded upon a commitment to provide safe and reliable energy at reasonable rates through a process of continual safety enhancement by proactively identifying and reducing pipeline integrity risks for distribution pipelines.[43] DIMP activities are required to comply with 49 CFR Part 192, Subpart P—Gas Distribution Pipeline Integrity Management. Pipeline and Hazardous Materials and Safety Administration (PHMSA) established DIMP requirements to enhance pipeline safety by having operators identify and reduce pipeline integrity risks for distribution pipelines, as required under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006.[44]

DIMP is a balanced program whereby the difference between actual and authorized O&M and capital-related costs are recorded to the Post-2011 DIMP balancing account (DIMPBA). For the years 2014 and 2015, DIMP-related costs were authorized to be recorded to the DIMPBA in accordance with OP 17 of D.13-05-010. For TY 2016, SDG&E recorded DIMP-related costs to the DIMPBA pursuant to D.16-06-054.

In the TY 2016 GRC, the direct testimony of the Pipeline Integrity for Transmission and Distribution witness presented Programs and Activities to Address Risk (PAAR). As stated in direct testimony, "PAARs are implemented through different avenues, depending on the threat being addressed… In alignment with PHMSA's intent and recognition that a PAAR needs to be operator-specific, SDG&E develops PAARs that are specific to the SDG&E system."[45] Since implementing DIMP, SDG&E has created several PAARs including:

- In 2013, SDG&E successfully completed a Sewer Lateral Inspection Program (SLIP) PAAR[46] and an evaluation of distribution anodeless risers. Completion of the project included records review and field inspections as required.
- The Distribution Risk Evaluation and Monitoring System (DREAMS) PAAR prioritizes certain early-vintage steel (pre-1960) and plastic (pre-1986), including Aldyl-A, for replacement. SDG&E will continue using risk evaluation to accelerate replacements on a targeted basis. The risk evaluation considers the leakage history, cathodic protection (for steel), vintage of the pipe, and the location.
- The Gas Infrastructure Protection Program (GIPP) PAAR addresses potential vehicular damage associated with above-ground distribution facilities. To address vehicular damage to Company facilities, SDG&E has identified, evaluated, and implemented a damage prevention solution that includes a collection of mitigation measures to address this threat.

The tables below illustrate the DIMP-related O&M and capital costs on a revenue requirement basis. As mentioned in Section 1c, the Utilities are presenting this balanced account program information in revenue requirement terms rather than direct expenditures to best represent how

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[43] A.14-11-003, Ex. 53 SDG&E/Martinez at iii.

[44] *Id*. at 13-14.

[45] *Id.* at 15.

[46] The SLIP PAAR addresses an emerging issue concerning pipeline damage associated with sewer laterals. The integrity threat comes from the use of trenchless technology during installation of pipelines. Trenchless technology provides a means of installing a pipeline without having to excavate a trench along the entire length of the pipeline.

the DIMP program is managed and reported in advice filings. For the 2014 and 2015 showing, the Utilities are providing information for the entire TY 2012 GRC cycle (2012-2015) because DIMP O&M and capital are managed over the authorized full GRC cycle, so any one particular year could be over or under-collected. For 2016, the table provides only the 2016 information, which was only the first year of the TY 2016 GRC cycle (2016-2018), and for the reasons stated above, the 2016 variance alone is not representative of what was spent compared to what was authorized for the entire TY 2016 GRC cycle.

Comparison of Authorized and Actual Revenue Requirement for 2012-2015

DIMP Balancing Account Details Revenue Requirements ($000)

	(a)	(b)	(c) = (a) - (b)	(d)	(e)=(c)+(d)
	Actual	Authorized [1/]	Under/ (Over) Collection	Interest	DIMPBA Balance
Year 2012:[1/]					
O&M	6,545	3,770	2,775		2,775
Capital-Related Costs	-	190	(190)		(190)
Interest				2	2
Subtotal	6,545	3,960	2,585	2	2,587
Year 2013:					
O&M	4,072	3,870	202		202
Capital-Related Costs[2/]	51	195	(144)		(144)
Cost of Capital Adjust.		(13)	13		13
Interest				3	3
Subtotal	4,123	4,051	72	3	75
Year 2014:					
O&M	2,640	3,976	(1,336)		(1,336)
Capital-Related Costs[2/]	184	187	(3)		(3)
Cost of Capital Adjust.			-		-
Interest				1	1
2014 Subtotal	2,824	4,163	(1,339)	1	(1,338)
Year 2015:					
O&M	2,137	4,085	(1,948)		(1,948)
Capital-Related Costs[2/]	370	190	180		180
Cost of Capital Adjust.			-		-
Interest				1	1
2015 Subtotal	2,507	4,275	(1,768)	1	(1,767)
Total TY2012 GRC Cycle for Years 2012-2015:					
O&M	15,394	15,701	(307)		(307)
Capital-Related Costs	605	762	(158)		(157)
Cost of Capital Adjust.	-	(13)	13		13
Interest				6	6
Total	**15,999**	**16,450**	**(451)**	**6**	**(445)**

[1/] Authorized O&M and capital-related revenue requirement increased by 2.65%/2.75% (2013/2014+) attrition adjustment adopted in 2012 GRC decision.

[2/] Actual capital-related costs also include the capital-related costs associated with capital additions from 2012 - 2014 and impact of the 2013 Cost of Capital.

GRC Cycle Variance Explanations:

DIMP O&M and capital are managed over the TY 2012 GRC cycle (2012 - 2015), so any particular year could be over or underspent compared to authorized. Note that the authorized capital amount in the regulatory balancing account is not the capital spending level, but is the capital-related costs, which comprise return on rate base, taxes on return, depreciation, and ad valorem tax.

Comparison of 2014 and 2015 "Proposed" Metrics Levels to 2014 and 2015 Actual Metrics Levels

The metrics included herein are provided to compare actual activity levels against what were assumed levels of work, herein noted as "planned" activity levels, during the TY 2012 and TY 2016 GRCs. Where a planned activity level is provided, it is based on planning assumptions in the GRC forecast for that specific activity. For some programs, however, "not comparable" indicates that SDG&E could not discern an easily identifiable assumed level of work (*e.g.*, each activity was not specifically forecasted or the planned activity changed when implemented). When the TY 2012 and TY 2016 GRCs were developed, the metrics or assumed level of activities supporting the forecasts were not anticipated to be used for these purposes, as the interim accountability reporting requirements were established after the fact in the TY 2016 GRC Decision. In addition, the metrics may have changed as the programs matured and the scope of planned activities changed over time. As an example, Excess Flow Valves were the exclusive remediation for the Gas Infrastructure Protection Program (GIPP) during the TY 2012 GRC. After further study and experience, the planned work that was then performed in 2014 and 2015 expanded to include gas infrastructure inspections, which also included bollards and relocations as remediation solutions. Thus, the number of GIPP inspections reported in the "Actual Activity Level" below, do not have a TY 2012 GRC "Planned Activity Level" for comparison. The anodeless riser program expanded to include steel riser inspection and mitigation. As such, the metrics in this report are not the optimal way to display this information. Future accountability reporting should consider better performance metrics to demonstrate progress over time as SDG&E gains long-term experience with such programs that evolve year over year, as well as knowledge through the TY 2019 GRC and S-MAP proceedings.

SDG&E DIMP Operating & Maintenance (O&M)	2014 Metrics	
	Actual Activity Level	Planned Activity Level
Sewer Lateral Inspection Program (SLIP)	Complete	Planned activity levels not comparable to actual activity levels
Gas Infrastructure Protection Program (GIPP)	470 Inspections	
Steel Riser Inspection & Mitigation	29,253 Inspections	36,000 Inspections

SDG&E DIMP Capital	2014 Metrics	
	Actual Activity Level	Planned Activity Level
Gas Infrastructure Protection Program (GIPP)	470 Inspections	Planned activity levels not comparable to actual activity levels
DREAMS: Aldyl-A Replacements	2 miles	4.2 miles

SDG&E DIMP Operating & Maintenance (O&M)	2015 Metrics	
	Actual Activity Level	Planned Activity Level
Sewer Lateral Inspection Program (SLIP)	Complete	Planned activity levels not comparable to actual activity levels
Gas Infrastructure Protection Program (GIPP)	Inspections Complete	
Steel Riser Inspection & Mitigation	25,603 Inspections	36,000 Inspections

SDG&E DIMP Capital	2015 Metrics	
	Actual Activity Level	Planned Activity Level
Gas Infrastructure Protection Program (GIPP)	Inspections Complete	Planned activity levels not comparable to actual activity levels
DREAMS: Aldyl-A Replacements	5 miles	4.2 miles

GRC Cycle Variance Explanations:

As part of the DIMP TY 2012 GRC request for 2012-2015, SDG&E requested funding for Programs and Activities to Address Risk, as discussed above. These PAAR programs, as intended, address risk above and beyond current regulatory requirements (federal and state). SDG&E executed on these PAARs; however, since the development of the workpapers in 2010, the scope of the programs was modified based on continual evaluation and results of the programs. For example, as explained above, the GIPP expanded beyond the proposed scope of Excess Flow Valve installation within the original GRC workpapers to include bollard protection and re-location of meter set assemblies. This expanded scope more adequately addresses the threat of vehicular damage. As such, since the scope has changed, the initial planned activity levels are listed as "not comparable" on the summary tables above. For the TY 2012 GRC, SDG&E attempted to estimate the scope of these PAARs. However, given the infancy of each of the programs, it was expected that the programs would continually adapt to program findings to adequately mitigate the risk being addressed.

Comparison of Authorized and Actual Revenue Requirement for 2016

DIMP Balancing Account Details Revenue Requirements ($000)

	(a)	(b)	(c) = (a) - (b)	(d)	(e)=(c)+(d)
	Actual	**Authorized**	**Under/ (Over) Collection**	**Interest**	**DIMPBA Balance**
Year 2016:					
O&M	3,552	6,306	(2,754)		(2,754)
Capital-Related Costs	515	821	(306)		(306)
Interest				(12)	(12)
Total	**4,067**	**7,127**	**(3,060)**	**(12)**	**(3,072)**

2016 Variance Explanation:

DIMP O&M and capital are managed over the TY 2016 GRC cycle (2016 - 2018), so any particular year could be over or underspent compared to authorized. Note that the authorized capital amount in the regulatory balancing account is not the capital spending level, but is the capital-related costs, which comprise return on rate base, taxes on return, depreciation, and ad valorem tax.

Comparison of 2016 "Proposed" Metrics Levels to 2016 Actual Metrics Levels

See explanation above for 2014 and 2015 comparison levels.

	2016 Metrics	
SDG&E DIMP Operating & Maintenance (O&M)	Actual Activity Level	Planned Activity Level
Riser Analysis, Inspection and Mitigation	63,875 Inspections	Planned activity levels not comparable to actual activity levels

	2016 Metrics	
SDG&E DIMP Capital	Actual Activity Level	Planned Activity Level
DREAMS: Aldyl-A Replacements	10 miles	17 miles

2016 Variance Explanations:

As part of the DIMP GRC request for the TY 2016 GRC Cycle (2016-2018), SDG&E requested funding for PAARs, as discussed above. These PAAR programs, as intended, address risk above and beyond current regulatory requirements (federal and state). SDG&E executed on these PAARs; however, since the development of the workpapers in 2014, the scope of the programs was modified based on continual evaluation and results of the programs. As such, since the scope changed, the initial planned activity levels are listed as "not comparable" on the summary table above. For the TY 2016 GRC, SDG&E attempted to estimate the scope of these PAARs. However, given the infancy of each of the programs, it was expected that the programs would continually adapt to program findings to adequately mitigate the risk being addressed.

4. SoCalGas Gas Operations – Gas Safety Risks, including projects, activities, and costs associated with DIMP, TIMP, and SIMP

a. SoCalGas Distribution Integrity Management Program

As described in the DIMP section for SDG&E, DIMP activities are required to comply with 49 CFR Part 192, Subpart P—Gas Distribution Pipeline Integrity Management. PHMSA established DIMP requirements to enhance pipeline safety by having operators identify and reduce pipeline integrity risks for distribution pipelines, as required under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006. DIMP-related costs are balanced and recorded in SoCalGas' DIMPBA.

DIMP comprises many PAARs, as explained in the SDG&E DIMP section above. In alignment with PHMSA's intent and recognition that a PAAR needs to be operator-specific, SoCalGas develops PAARs that are specific to the SoCalGas system. SoCalGas-specific PAARs include:

- DREAMS PAAR prioritizes certain early-vintage steel (pre-1960) and plastic (pre-1986), including Aldyl-A, for replacement. SoCalGas has implemented a risk evaluation system to accelerate replacements on a targeted basis. The risk evaluation considers the leakage history, cathodic protection (for steel), vintage of the pipe, and the location.
- The Distribution Riser Inspection Program (DRIP) PAAR addresses the threat of failures of anodeless risers. Anodeless risers are service line components that have shown a propensity to fail before the end of their useful lives.
- The GIPP PAAR addresses potential vehicular damage associated with above-ground distribution facilities. To address vehicular damage to Company facilities, SoCalGas has identified, evaluated, and implemented a damage prevention solution that includes a collection of mitigation measures to address this threat.
- The SLIP PAAR addresses an emerging issue concerning pipeline damage associated with sewer laterals. The integrity threat comes from the use of trenchless technology during installation of pipelines. Trenchless technology provides a means of installing a pipeline without having to excavate a trench along the entire length of the pipeline. The project includes records review and field inspections as required.

The tables below illustrate the DIMP-related O&M and capital costs on a revenue requirement basis. As mentioned in Section 1c, the Utilities are presenting this balanced account program information in revenue requirement terms rather than direct expenditures to best represent how the DIMP program is managed and reported in advice letter filings. For the 2014 and 2015 showing, the Utilities are providing information for the entire TY 2012 GRC cycle (2012-2015) because DIMP O&M and capital are managed over the authorized full GRC cycle, so any one particular year could be over or under-collected. For 2016, the table provides only the 2016 information, which was only the first year of the TY 2016 GRC cycle (2016- 2018), and for the reasons stated above, the 2016 variance alone is not representative of what was spent compared to what was authorized for the entire TY 2016 GRC cycle.

Comparison of Authorized and Actual Revenue Requirement 2012-2015

DIMP Balancing Account Details Revenue Requirements ($000)

	(a)	(b)	(c) = (a) - (b)	(d)	(e)=(c)+(d)
	Actual	**Authorized [1/]**	**Under/ (Over) Collection**	**Interest**	**DIMPBA Balance**
Year 2012:[2/]					
O&M	18,683	27,369	(8,686)		(8,686)
Capital-Related Costs	22	651	(629)		(629)
Interest				(14)	(14)
Subtotal	18,705	28,020	(9,315)	(14)	(9,329)
Year 2013:					
O&M	39,879	28,094	11,785		11,785
Capital-Related Costs[3/]	474	668	(194)		(194)
Cost of Capital Adjust.		(36)	36		36
Interest				(11)	(11)
Subtotal	40,353	28,727	11,626	(11)	11,615
Year 2014:					
O&M	25,800	28,867	(3,067)		(3,067)
Capital-Related Costs[3/]	1,329	650	679		679
Cost of Capital Adjust.			-		-
Interest				2	2
2014 Subtotal	27,129	29,517	(2,388)	2	(2,386)
Year 2015:					
O&M	23,531	29,661	(6,130)		(6,130)
Capital-Related Costs[3/]	3,209	668	2,541		2,541
Cost of Capital Adjust.			-		-
Interest				(5)	(5)
2015 Subtotal	26,740	30,329	(3,589)	(5)	(3,594)
Total TY2012 GRC Cycle for Years 2012-2015:					
O&M	107,893	113,991	(6,098)		(6,098)
Capital-Related Costs	5,034	2,637	2,397		2,397
Cost of Capital Adjust.	-	(36)	36		36
Interest				(28)	(28)
Total	**112,927**	**116,592**	**(3,665)**	**(28)**	**(3,693)**

[1/] Recorded O&M expenses includes an adjustment for certain prior year expenses removed from DIMPBA as a result of the Energy Division's review of DIMP expenses.

[2/] Authorized O&M and capital-related revenue requirement increased by 2.75% attrition adjustment adopted in 2012 GRC decision.

[3/] Actual capital-related costs also include the capital-related costs associated with capital additions from 2012 - 2014 and impact of the 2013 Cost of Capital.

GRC Cycle Variance Explanations:

DIMP O&M and capital are managed over the TY 2012 GRC cycle (2012 - 2015), so any particular year could be over or underspent compared to authorized. Note that the authorized capital amount in the regulatory balancing account is not the capital spending level, but is the capital-related costs, which comprise return on rate base, taxes on return, depreciation, and ad valorem tax.

Comparison of 2014 and 2015 "Proposed" Metrics Levels to 2014 and 2015 Actual Metrics Levels

The metrics included herein are provided to compare actual activity levels against what were assumed levels of work, herein noted as "planned" activity levels, during the TY 2012 and TY 2016 GRCs. Where a planned activity level is provided, it is based on planning assumptions in the GRC forecast for that specific activity. For some programs, however, "not comparable" indicates that SoCalGas could not discern an easily identifiable assumed level of work (*e.g.*, each activity was not specifically forecasted or the planned activity changed when implemented). When the TY 2012 and TY 2016 GRCs were developed, the metrics or assumed level of activities supporting the forecasts were not anticipated to be used for these purposes, as the interim accountability reporting requirements were established after the fact in the TY 2016 GRC Decision. In addition, the metrics may have changed as the programs matured and the scope of planned activities changed over time. As an example, Excess Flow Valves were the exclusive remediation for the Gas Infrastructure Protection Program (GIPP) during the TY 2012 GRC. After further study and experience, the planned work that was then performed in 2014 and 2015 expanded to include gas infrastructure inspections, which also included bollards and relocations as remediation solutions. Thus, the number of GIPP inspections reported in the "Actual Activity Level" below, do not have a TY 2012 GRC "Planned Activity Level" for comparison. As such, the metrics in this report are not the optimal way to display this information. Future accountability reporting should consider better performance metrics to demonstrate progress over time as SoCalGas gains long-term experience with such programs that evolve year over year, as well as knowledge through the TY 2019 GRC and S-MAP proceedings.

SoCalGas DIMP Operating & Maintenance (O&M)	2014 Metrics Actual Activity Level	 Planned Activity Level
Sewer Lateral Inspection Program (SLIP) Cleared by Field Inspection	224,660 Services Cleared	75,859 Services Cleared
Gas Infrastructure Protection Program (GIPP) Mitigations (combined O&M and Capital)	123,300 Inspections	Planned activity levels not comparable to actual activity levels
Anodeless Riser Inspection & Mitigation	68,700 mitigations	

SoCalGas DIMP Capital	2014 Metrics Actual Activity Level	 Planned Activity Level
DREAMS: Early-vintage Steel Replacements	4 miles	30 miles
DREAMS: Early-vintage Aldyl-A Replacements	0 miles	15 miles
Gas Infrastructure Protection Program (GIPP) Mitigations (combined O&M and Capital)	123,300 Inspections	Planned activity levels not comparable to actual activity levels

SoCalGas DIMP Operating & Maintenance (O&M)	2015 Metrics Actual Activity Level	 Planned Activity Level
Sewer Lateral Inspection Program (SLIP) Cleared by Field Inspection	169,700 Services Cleared	75,859 Services Cleared
Gas Infrastructure Protection Program (GIPP) Mitigations (combined O&M and Capital)	7,800 Inspections	Planned activity levels not comparable to actual activity levels
Anodeless Riser Inspection & Mitigation	92,900 mitigations	

SoCalGas DIMP Capital	2015 Metrics Actual Activity Level	 Planned Activity Level
DREAMS: Early-vintage Steel Replacements	11 miles	30 miles
DREAMS: Early-vintage Aldyl-A Replacements	2 miles	15 miles
Gas Infrastructure Protection Program (GIPP) Mitigations (combined O&M and Capital)	7,800 Inspections	Planned activity levels not comparable to actual activity levels

GRC Cycle Variance Explanations:

As part of the DIMP TY 2012 GRC request for 2012-2015, SoCalGas requested funding for PAARs, as discussed above. These PAAR programs, as intended, address risk above and beyond current regulatory requirements (federal and state). SoCalGas executed on these PAARs; however, since the development of the workpapers in 2010, the scope of the programs was modified based on continual evaluation and results of the programs. For example, as explained above, for the SLIP, it was recognized that additional services would require review and the rate of services inspected per year would significantly increase. In addition, for the GIPP, the program expanded beyond the proposed scope of Excess Flow Valve installation to include bollard protection and re-location of meter set assemblies. This expanded scope more adequately addresses the threat of vehicular damage. As such, since the scope has changed, the initial planned activity levels are listed as "not comparable" on the summary tables above. For the TY 2012 GRC, SoCalGas attempted to estimate the scope of these PAARs. However, given the infancy of each of the programs, it was expected that the programs would adapt to program findings to adequately mitigate the risk being addressed.

Comparison of Authorized and Actual Revenue Requirement for 2016

DIMP Balancing Account Details Revenue Requirements ($000)

	(a)	(b)	(c) = (a) - (b)	(d)	(e)=(c)+(d)
	Actual	**Authorized**	**Under/ (Over) Collection**	**Interest**	**DIMPBA Balance**
Year 2016:					
O&M	32,409	44,060	(11,651)		(11,651)
Capital-Related Costs	2,193	4,406	(2,213)		(2,213)
Interest				(63)	(63)
Total	**34,602**	**48,466**	**(13,864)**	**(63)**	**(13,927)**

2016 Variance Explanation:

DIMP O&M and capital are managed over the TY 2016 GRC cycle (2016 - 2018), so any particular year could be over or underspent compared to authorized. Note that the authorized capital amount in the regulatory balancing account is not the capital spending level, but is the capital-related costs, which comprise return on rate base, taxes on return, depreciation, and ad valorem taxes.

Comparison of 2016 "Proposed" Metrics Levels to 2016 Actual Metrics Levels

See explanation above for 2014 and 2015 comparison levels.

	2016 Metrics	
SoCalGas DIMP Operating & Maintenance (O&M)	Actual Activity Level	Planned Activity Level
Sewer Lateral Inspection Program (SLIP) Cleared by Field Inspection	61,180 Services Cleared	50,000 Services Cleared
Gas Infrastructure Protection Program (GIPP) Mitigations (combined O&M and Capital)	6,245 Inspections/Mitigations	6,558 Inspections/Mitigations
Distribution Riser Inspection Project (DRIP) Inspections/Mitigations	172,600 Inspections/Mitigations	225,000 Inspections/Mitigations

	2016 Metrics	
SoCalGas DIMP Capital	Actual Activity Level	Planned Activity Level
DREAMS: Early-vintage Steel Replacements	25 miles	37 miles
DREAMS: Early-vintage Aldyl-A Replacements	11 miles	18 miles
Gas Infrastructure Protection Program (GIPP) Mitigations (combined O&M and Capital)	6,245 Inspections/Mitigations	6,558 Inspections/Mitigations

2016 Variance Explanation:

As part of the DIMP GRC request for the TY 2016 GRC Cycle (2016-2018), SoCalGas requested funding for PAARs, as discussed above. These PAAR programs, as intended, address risk above and beyond current regulatory requirements (federal and state). SoCalGas executed on these PAARs; however, since the development of the workpapers in 2014, the scope of the programs was modified based on continual evaluation and results of the programs. For example, for the SLIP, it was recognized that additional services would require review and the rate of services inspected per year would significantly increase. In addition, for the GIPP, the program expanded beyond the proposed scope of Excess Flow Valve installation to include bollard protection and re-location of meter set assemblies. This expanded scope more adequately addresses the threat of vehicular damage. As such, since the scope changed, the initial planned activity levels are listed as "not comparable" on the summary tables above. For the TY 2016 GRC, SoCalGas attempted to estimate the scope of these PAARs. However, given the infancy of each of the programs, it was expected that the programs would continually adapt to program findings to adequately mitigate the risk being addressed.

b. SoCalGas Transmission Integrity Management Program

TIMP supports SoCalGas' goals of operating the system safely and with excellence by continually assessing, mitigating, and reducing system risk. To comply with 49 CFR 192, Subpart O—Gas Transmission Pipeline Integrity Management, SoCalGas is required to continually identify threats to transmission pipelines located in High Consequence Areas (HCAs), determine the risk posed by these threats, schedule and track assessments to address threats within prescribed timelines, collect information about the condition of the pipelines, take actions to minimize applicable threats and integrity concerns to reduce the risk of a pipeline failure, and report findings to regulators. TIMP-related costs are balanced and recorded in a regulatory balancing account, the TIMP Balancing Account (TIMPBA).

In the 2016 GRC testimony, SoCalGas presented various activities including an Assessment category. TIMP's allowable options in Assessments are:

- In-line Inspection (ILI) - The in-line inspection method utilizes specialized inspection tools that travel inside the pipeline. ILI tools are often referred to as "smart pigs." Smart pigs come in a variety of types and sizes with different measurement capabilities that assist in collecting information about the pipeline.[47]
- Pressure Test - Pressure testing is a method that uses a hydraulic approach by filling the pipeline, usually with water, at a pressure greater than the maximum allowable operating pressure of the pipeline for fixed period of time. In certain circumstances, the pipeline may be temporarily removed from service post-construction, pressure-tested, and then returned to service. If a leak occurs during the pressure test, the leak is investigated and remediated prior to continuing or completing a pressure test.[48]
- External Corrosion Direct Assessment (ECDA) - ECDA is a process that proactively seeks to identify external corrosion defects before they grow to a size that can affect the integrity of the inspected pipeline. The ECDA process requires integration of operating data and the completion of above-ground surveys. This information is used to identify

[47] A.14-11-004, Ex. 49 SCG/Martinez at 10.

[48] *Id.*

> and define the severity of coating faults, diminished cathodic protection. and areas where corrosion may have occurred or may be occurring.[49]

Similar to the SoCalGas DIMP showing above, the tables below illustrate the TIMP-related O&M and capital costs on a revenue requirement basis. As mentioned in Section 1c, the Utilities are presenting this balanced account program information in revenue requirement terms rather than direct expenditures to best represent how the TIMP program is managed and reported in advice letter filings. For the 2014 and 2015 showing, the Utilities are providing information for the entire TY 2012 GRC cycle (2012-2015) because TIMP O&M and capital are managed over the authorized full GRC cycle, so any one particular year could be over or under-collected. For 2016, the table provides only the 2016 information, which was only the first year of the TY 2016 GRC cycle (2016 – 2018), and for the reasons stated above, the 2016 variance alone is not representative of what was spent compared to what was authorized for the entire TY 2016 GRC cycle.

[49] *Id.* at 10-11.

Comparison of Authorized and Actual Revenue Requirement 2012-2015

TIMP Balancing Account Details Revenue Requirements ($000)

	(a)	(b)	(c) = (a) - (b)	(d)	(e)=(c)+(d)
	Actual	Authorized [1/]	Under/ (Over) Collection	Interest	TIMPBA Balance
Year 2012:[2/]					
O&M	40,816	28,612	12,204		12,204
Capital-Related Costs	102	948	(846)		(846)
Interest				3	3
Subtotal	40,918	29,560	11,358	3	11,362
Year 2013:					
O&M	45,252	29,370	15,882		15,882
Capital-Related Costs[3/]	2,673	973	1,700		1,700
Cost of Capital Adjust.		(52)	52		52
Interest				21	21
Subtotal	47,925	30,291	17,634	21	17,655
Year 2014:					
O&M	42,686	30,178	12,508		12,508
Capital-Related Costs[3/]	7,531	946	6,585		6,585
Cost of Capital Adjust.			-		-
Interest				37	37
2014 Subtotal	50,217	31,124	19,093	37	19,130
Year 2015:					
O&M	37,820	31,008	6,812		6,812
Capital-Related Costs[3/]	10,997	972	10,025		10,025
Cost of Capital Adjust.			-		-
Interest				79	79
2015 Subtotal	48,817	31,980	16,837	79	16,916
Total TY2012 GRC Cycle for Years 2012-2015:					
O&M	166,573	119,168	47,405		47,405
Capital-Related Costs	21,303	3,839	17,464		17,464
Cost of Capital Adjust.	-	(52)	52		52
Interest				140	140
Total	**187,877**	**122,955**	**64,921**	**140**	**65,062**

[1/] Recorded O&M expenses includes an adjustment for certain prior year expenses removed from TIMPBA as a result of the Energy Division's review of TIMP expenses.

[2/] Authorized O&M and capital-related revenue requirement increased by 2.75% attrition adjustment adopted in 2012 GRC decision.

[3/] Actual capital-related costs also include the capital-related costs associated with capital additions from 2012 - 2014 and impact of the 2013 Cost of Capital.

GRC Cycle Variance Explanations:

For the TY 2012 GRC cycle, TIMP was overspent compared to its authorized revenue requirement, resulting in an under-collected balanced in the TIMPBA. This occurred for three reasons. First, in D.13-05-010, the Commission did not authorize SoCalGas to recover the entire forecast cost of implementing its TIMP. Second, in early 2010, when SoCalGas prepared its TY 2012 GRC application, SoCalGas did not anticipate the resources that would later be required to address the heightened focus on transmission integrity as a consequence of the rupture of a Pacific Gas and Electric Company transmission pipeline on September 10, 2010. Since the pipeline rupture in San Bruno, California, regulations such as "The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011," have led the PHMSA to change its reporting requirements and review the existing transmission integrity requirements to identify areas for improvement. Third, there is an impact as a result of how capital expenditures are recovered and balanced. As discussed in Section 1c, the amount recovered by SoCalGas for TIMP-related capital is less than actual capital-related costs recorded to the TIMPBA.

It should be noted that SoCalGas has requested recovery of under-collected balances in the TIMBA through three advice letter filings during the 2012-2015 GRC cycle.[50]

Comparison of 2014 and 2015" Proposed" Metrics Levels to 2014 and 2015 Actual Metrics Levels

The metrics included herein are provided to compare actual activity levels against what were assumed levels of work, herein noted as "planned" activity levels, during the TY 2012 and TY 2016 GRCs. Where a planned activity level is provided, it is based on planning assumptions in the GRC forecast for that specific activity. For some programs, however, "not comparable" indicates that SoCalGas could not discern an easily identifiable assumed level of work (*e.g.*, each activity was not specifically forecasted). When the TY 2012 and TY 2016 GRCs were developed, the metrics or assumed level of activities supporting the forecasts were not anticipated to be used for these purposes, as the interim accountability reporting requirements were established after the fact in the TY 2016 GRC Decision. In addition, the metrics may have changed as the programs matured and the scope of planned activities changed over time. As such, the metrics in this report are not the optimal way to display this information. Future accountability reporting should consider better performance metrics to demonstrate progress over time as SoCalGas gains long-term experience with such programs that evolve year over year, as well as knowledge through the TY 2019 GRC and S-MAP proceedings.

[50] Advice Letter 4632, approved in Resolution G-3499 (June 11, 2015); Advice Letter 4819, approved in Resolution G-3517 (May 12, 2016); and Advice Letter 5057, which was filed on November 4, 2016 and is currently pending.

SoCalGas TIMP Operating & Maintenance (O&M) and Capital	2014 Metrics	
	Actual Activity Level	Planned Activity Level
Assessment: In-Line Inspection	393 miles	Planned activity levels not comparable to actual activity levels
Assessment: Pressure Testing	0 miles	
Assessment: External Corrosion Direct Assessment	45 miles	

SoCalGas TIMP Operating & Maintenance (O&M) and Capital	2015 Metrics	
	Actual Activity Level	Planned Activity Level
Assessment: In-Line Inspection	246 miles	Planned activity levels not comparable to actual activity levels
Assessment: Pressure Testing	0 miles	
Assessment: External Corrosion Direct Assessment	27 miles	

GRC Cycle Variance Explanations:

For the TIMP, at a minimum, transmission pipelines within densely populated areas require an assessment (ILI, Pressure Test or ECDA) every 7 years. To meet deadlines for TIMP assessments, schedules may be modified each year to account for resource, inspection tools, and system availability. For the TY 2012 GRC, a zero-based forecast was provided for assessment projects intended to be completed in 2010 and 2011. SoCalGas and SDG&E used a zero-based forecast methodology because the number of assessment projects changes from year to year. SoCalGas and SDG&E have attempted to level out the number of assessment projects completed each year to avoid large fluctuations in cost from year to year, but fluctuations still exist; therefore, it is not useful to compare the planned activity level from 2010 and 2011 to 2014 and 2015 to measure performance for a program with a long-term assessment cycle. Accordingly, the "planned" metrics are listed as "not comparable." It should be noted that all TIMP assessments were completed on time, meeting regulatory deadlines for 2014 and 2015.

Comparison of Authorized and Actual Revenue Requirement 2016

TIMP Balancing Account Details Revenue Requirements ($000)

	(a)	(b)	(c) = (a) - (b)	(d)	(e)=(c)+(d)
	Actual	**Authorized**	**Under/ (Over) Collection**	**Interest**	**TIMPBA Balance**
Year 2016:					
O&M	40,023	57,571	(17,548)		(17,548)
Capital-Related Costs	744	1,363	(619)		(619)
Interest				139	139
Total	**40,767**	**58,934**	**(18,167)**	**139**	**(18,028)**

2016 Variance Explanation:

For the TY 2016 GRC cycle (2016 – 2018), TIMP was underspent compared to its authorized revenue requirement, resulting in an over-collected balanced in the TIMPBA. This occurred because as mentioned above, the Utilities manage the TIMP O&M and capital over the authorized full TY 2016 GRC cycle (2016 -2018), so any one particular year could be over or under-collected.

Comparison of 2016 "Proposed" Metrics Levels to 2016 Actual Metrics Levels

See explanation above for 2014 and 2015 comparison levels.

	2016 Metrics	
SoCalGas TIMP Operating & Maintenance (O&M) and Capital	Actual Activity Level	Planned Activity Level
Assessment: In-Line Inspection	333 miles	615 miles
Assessment: Pressure Testing	4 miles	0 miles
Assessment: External Corrosion Direct Assessment	30 miles	33 miles

2016 Variance Explanation:

For the TIMP, at a minimum, transmission pipelines within densely populated areas require an assessment (ILI, Pressure Test, or ECDA) every 7 years. To meet deadlines for TIMP assessments, schedules may be modified each year to account for resources, inspection tools, and system availability. For the TY 2016 GRC, a zero-based forecast was provided for assessment projects intended to be completed in the years TY 2016 through 2018. SoCalGas and SDG&E used a zero-based forecast methodology because the number of assessment projects changes from year to year. SoCalGas and SDG&E have attempted to level out the number of assessment projects completed each year to avoid large fluctuations in costs from year to year, but fluctuations still exist; therefore, where TY 2016 GRC planning assumptions were available for these activities, it is not useful to compare the planned activity level in 2016 alone to actual levels in 2016, to measure performance for a program with a long-term assessment cycle, until all three years are available. However, it should be noted that all TIMP assessments were completed on time, meeting regulatory deadlines for 2016 and additional inspections have been completed during 2017 and are planned for 2018 to ensure continued compliance.

Additionally, during 2016, the ILI rate was lower than planned due to multiple inspections that had to occur on the same lines, which extended the completion date to the following year. For example, during an ILI, the tool would become lodged and retrofitting of the pipeline needed to occur prior to attempting a second ILI. The mileage reflected in the accountability report is based on a successful ILI assessment and does not account for mileage attempted. As previously mentioned, it is expected that during this iterative process, the performance metrics will continue to improve to better demonstrate accountability.

c. SoCalGas Storage Integrity Management Program

SoCalGas proposed to institute a new approach to storage integrity management, the SIMP, modeled after the TIMP and the DIMP, in its Test Year 2016 GRC Application, A.14-11-004, filed in November 2014. The SIMP is a "proactive program of SoCalGas to ensure the integrity of SoCalGas' underground gas storage facilities, and to detect and repair problems before they occur."[51] D.16-06-054, effective on January 1, 2016, approved the SIMP on June 23, 2016 and provided for the establishment of a two-way balancing account for SIMP expenditures.[52]

In accordance with D.16-06-054, SoCalGas filed Advice Letter 5000 on July 29, 2016, effective on August 28, 2016, to establish the SIMP Balancing Account (SIMPBA). Pursuant to Ordering Paragraph 8 of D.16-06-054, the SIMPBA records the difference between actual and authorized costs associated with SoCalGas' SIMP effective with the TY 2016 GRC cycle. The SIMPBA is authorized for the three-year GRC period from January 1, 2016 to December 31, 2018 or until the effective implementation date of SoCalGas' next GRC.

Similar to the showing for TIMP and DIMP and as discussed in Section 1c, the Utilities are presenting this information in revenue requirement terms rather than direct expenditures to best represent how the SIMP program is managed.

As seen in the tables below, because the formal SIMP was not approved until June 23, 2016 in D.16-06-054 and effective January 1, 2016, there are not any recorded actuals or "SIMP"-related revenue requirement recorded to the SIMPBA in the years 2014 and 2015. However, while the TY 2016 GRC was pending, SoCalGas continued to undertake integrity management work at the storage facilities using traditional GRC funding.

<u>Comparison of Authorized and Actual Revenue Requirement 2014-2015</u>

SIMP Balancing Account Details Revenue Requirement ($000)

	(a)	*(b)*	*(c) = (a) - (b)*	*(d)*	*(e)=(c)+(d)*
Year 2014:[1/]	**Actual**	**Authorized** [1/]	**Under/ (Over) Collection**	**Interest**	**SIMPBA Balance**
O&M	-	-	-	-	-
Capital-Related Costs	-	-	-	-	-
Interest	-	-	-	-	-
Subtotal	-	-	-	-	-

[1/] Authorized O&M and capital-related revenue requirement were adopted in TY2016 GRC decision. SoCalGas was not authorized to record dollars to SIMPBA prior to 2016.

[51] D.16-06-054 at 5.

[52] *Id*. at OP 8.

2014 Variance Explanation:

In 2014, because the SIMP balancing account had not yet been authorized, no costs could be recorded in the SIMP account. Although SIMP had not yet been approved, SoCalGas undertook integrity management work at the storage facilities using traditional GRC funding. This work incorporated certain SIMP-planned activities and is identified as "Program Support" in the below metrics. In 2014, this work included the SIMP pilot program, which involved running integrity tests of the Frew 2 and Porter 42B wells at Aliso Canyon. The recorded capital expenses for the Frew 2 and Porter 42B pilot work totaled approximately $1.67 million and $1.27 million, respectively.

SIMP Balancing Account Details Revenue Requirement ($000)

	(a)	*(b)*	*(c) = (a) - (b)*	*(d)*	*(e)=(c)+(d)*
Year 2015:[1/]	Actual	Authorized [1/]	Under/ (Over) Collection	Interest	SIMPBA Balance
O&M	-	-	-	-	-
Capital-Related Costs	-	-	-	-	-
Interest	-	-	-	-	-
Subtotal	-	-	-	-	-

[1/] Authorized O&M and capital-related revenue requirement were adopted in TY2016 GRC decision. SoCalGas was not authorized to record dollars to SIMPBA prior to 2016.

2015 Variance Explanation:

In 2015, because the SIMP balancing account had not yet been authorized, no costs could be recorded in the SIMP account. SoCalGas did incur approximately $180,000 in direct O&M expenses for Well View data entry efforts to prepare SoCalGas' storage data and prioritize wells for SIMP testing.[53] These expenses were funded through traditional GRC funding.

The 2015 SIMP capital work was completed in parallel with ongoing traditional GRC Capital well activities. In 2015, well logging activities and well site enhancement projects[54] at the 4 SoCalGas storage facilities, or "fields" were identified as SIMP activities, since both result in data used for SIMP. These activities are identified below as "Program Support" for the metrics. The recorded direct capital costs associated with this work was $214,000 and $625,000, respectively.

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[53] The purpose of this project was to enter historical well information/data into the well data management database called WellView. New well workover, drilling, and abandonment data is entered, maintained, and accessible via this database. The goal was to enter historical information into this database so it is a one stop shop for the team.

[54] This project raised and relocated the annulus gas venting system to above grade, and installed standardized racks for well pressure monitoring and installed continues pressure monitoring on all wells. Real-time pressure monitoring provides continuous monitoring of well integrity, improved management of well performance, and optimization of field deliverability and facilitates well and pipeline integrity operations. Additionally, continuous pressure monitoring is an important component of the SIMP.

Comparison of 2014 and 2015 "Proposed" Metrics Levels to 2014 and 2015 Actual Metrics Levels

SoCalGas is providing the metrics below to illustrate the progress made with regard to storage integrity.

For the SIMP Capital metrics, the 2014 metrics for "Program Support" includes the SIMP pilot on one well. In the 2015 SIMP Capital metrics, "Program Support" includes capital work performed at all 4 fields in support of developing SIMP activities. SoCalGas' capital funding proposals in 2014 and 2015 were made to develop the TY 2016 Revenue Requirement, but not technically implemented in rates until 2016. Work performed during 2014 and 2015 was performed under other Underground Storage GRC capital budgets.

For the SIMP O&M metrics, "Data Management" includes SoCalGas' Well View data entry efforts that prepared SoCalGas' storage data and prioritized wells for SIMP testing.

	2014 Metrics		2015 Metrics	
SIMP Capital	Actual Activity Level	Planned Activity Level	Actual Activity Level	Planned Activity Level
Company Labor (FTE's)	0	0.5	0	0.6
Program Support	1 Well	1 Well	4 Fields	4 Fields

	2014 Metrics [1]		2015 Metrics [1]	
SIMP O&M	Actual Activity Level	Planned Activity Level	Actual Activity Level	Planned Activity Level
Company Labor (FTE's)	0	not planned	0.2	not planned
Data Management	0	not planned	1 Field of Well View Data Entry	not planned

Note 1: O&M funding was not requested until TY2016.

Comparison of Authorized and Actual Revenue Requirement 2016

SIMP Balancing Account Details Revenue Requirement ($000)

	(a)	*(b)*	*(c) = (a) - (b)*	*(d)*	*(e)=(c)+(d)*
Year 2016:[1/]	**Actual**	**Authorized [1/]**	**Under/ (Over) Collection**	**Interest**	**SIMPBA Balance**
O&M	11,814	5,910	5,904		5,904
Capital-Related Costs	672	361	311		311
Interest				7	7
Subtotal	12,486	6,271	6,215	7	6,222

2016 Variance Explanation:

Since the Commission's authorization of SIMP in TY 2016, and to respond to new and proposed regulatory requirements on gas storage projects, SoCalGas has accelerated the pace of SIMP inspections of the gas storage wells at Aliso Canyon, Honor Rancho, Playa de Rey, and La Goleta gas storage fields. O&M expenses primarily include mandated well inspections, wellbore inspection logs, noise and temperature surveys, and surface piping inspections. O&M expenses for TY 2016 also include: data management, reservoir and geologic studies, and labor. Capital expenses for 2016 are for gas storage well workovers[55] to prepare wells for inspection logging and to follow-up on the inspection logging. These workovers consist of mitigation for the safe return to operation, and are the definition of 2016 "Program Support" in the metrics below. Mitigation includes new tubing installed in all wells. If the well cannot be placed back in service, the work includes safely isolating the well from the gas storage reservoir until the well is plugged and abandoned. This accelerated pace of these activities resulted in TY 2016 SIMP recorded actuals exceeding the authorized funding level.

Comparison of 2016 Proposed Metrics Levels to 2016 Actual Metrics Levels

	2016 Metrics	
SIMP Capital	Actual Activity Level	Planned Activity Level
Company Labor (FTE's)	1.5	6.5
Program Support	33 wells	28 wells

	2016 Metrics	
SIMP O&M	Actual Activity Level	Planned Activity Level
Company Labor (FTE's)	14.3	5.5
Data Management	2 Fields of Well View Data Entry	1 Field of Well View Data Entry
Well Inspections	43 wells	40 wells

Note 1: O&M funding was not requested until TY2016.

2016 Variance Explanation:

As noted above, the SIMP "Program Support" metric evolved from a pilot in 2014, to field work in 2015, to well workover[56] activity in 2016. SIMP TY 2016 capital testimony forecasted 28 storage well workovers per year. Due to the accelerated pace as described above, the actual activity level in 2016 was 33 completed storage well workovers. The primary drivers for acceleration are new, emerging, and proposed regulations and industry best practices. The TY

[55] The Direct Testimony of Phillip Baker refers to this activity as "Wells Requiring Capital Mitigation Work." See A.14-11-004, Ex. 45 SCG/Baker at 42.
[56] Preparation of wells for inspection logging, and follow-up on the inspection logging with mitigation, including tubing replacement.

2016 testimony also forecasted 6.5 FTEs, primarily contract administrators, with 1 FTE for a well mitigation project manager. The variance in labor is due to the use of contracted labor.

For SIMP O&M, the metrics used was for “Well Inspections” and “Data Management.” Well Inspection involved well integrity inspections conducted via utilizing a variety of tools to assess well casing integrity. SIMP TY 2016 O&M testimony forecasted 40 well inspections per year. Due to the accelerated pace as referenced previously, the actual activity level in 2016 was 43 full storage well inspections. There were also 105 partial inspections of gas storage wells that included noise and temperature surveys and pressure tests. The primary drivers for acceleration are new, emerging, and proposed regulations and industry best practices. Two of the storage fields’ datasets were entered into WellView in 2016, exceeding the plan of 1 storage field. This variance is consistent with the accelerated pace of other SIMP activities. The variance in FTEs reflects a focus on accelerated inspection work, and focus of company labor on supporting inspections. The variance in well numbers also reflects the accelerated pace.

GLOSSARY OF TERMS

A.	Application
ADA	American Disabilities Act
ALJ	Administrative Law Judge
CAL FIRE	California Department of Forestry and Fire Protection
CCUE	Coalition of California Utility Employees
CFR	Code of Federal Regulations
CNF	Cleveland National Forest
D.	Decision
DOE	Do Not Operate Energized
DIMP	Distribution Integrity Management Program
DIMPBA	Distribution Integrity Management Program Balancing Account
DREAMS	Distribution Risk Evaluation and Monitoring System
DRIP	Distribution Riser Inspection Project
ECDA	External Corrosion Direct Assessment
ED	Energy Division
FAA	Federal Aviation Administration
FiRM	Fire Risk Management
FTEs	Full-Time Equivalents
GIPP	Gas Infrastructure Protection Program
GIS	Geographic Information System
GRC	General Rate Case
HCAs	High Consequence Areas
I.	Investigation
ILI	In-Line Inspection
LiDAR	Light Detection and Rating
O&M	Operations and Maintenance
OP	Ordering Paragraph
OSA	Office of Safety Advocates
PAAR	Programs and Activities to Address Risk
PHMSA	Pipeline and Hazardous Materials and Safety Administration

PLS-CADD	Power Line Systems – Computer Aided Design and Drafting
PTC	Permit to Construct
RAMP	Risk Assessment Mitigation Phase
RCP	Rate Case Plan
RIRAT	Reliability Improvements in Rural Areas Team
RO	Results of Operation
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB	Senate Bill
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
SED	Safety and Enforcement Division
SF6	Sulfur Hexafluoride
SIMP	Storage Integrity Management Program
SIMPBA	Storage Integrity Management Program
SLIP	Sewer Lateral Inspection Program
S-MAP	Safety Model Assessment Proceeding
SoCalGas	Southern California Gas Company
UCLA	University of California, Los Angeles
USA	Underground Service Alert
U.S. Forest	United States Forest Service
TIMP	Transmission Integrity Management Program
TIMPBA	Transmission Integrity Management Program Balancing Account
TMED	Threshold Major Event Days
TY	Test Year
WRRM	Wildfire Risk Reduction Model