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 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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June 30, 2017

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Pursuant to Ordering Paragraph (O.P.) 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) hereby submit their Interim Spending Accountability Report (Interim Report), attached hereto as an Appendix. This Interim Report is timely filed within one year of the issuance date of D.16-06-054, July 1, 2016, in accordance with O.P. 11.

O.P. 11. requires 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 the Interim Report and to propose a methodology for reporting and comparing the projected versus actual benefits of its risk mitigation activities. Further, O.P. 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." The format and content of the

Interim Report attached hereto has been prepared in accordance with those discussions and with the requirements set forth in D.16-06-054, O.P. 11.

A subsequent 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 Interim Report in their Risk Assessment Mitigation Plan (RAMP) proceeding. Given that the above-captioned proceeding is currently open, and in accordance with email guidance from Administrative Law Judge (ALJ) John Wong on June 28, 2017, SDG&E and SoCalGas hereby concurrently file their Interim Report both in the above-captioned proceeding and in their pending RAMP proceeding, Investigation (I.) 16-10-015/-016 (cons.), and serve the Interim Report upon the official service lists for those two proceedings.

Dated at San Diego, California, this 30th day of June, 2017.

Respectfully submitted,

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Appendix

Southern California Gas Company and San Diego Gas & Electric Company

Interim Spending Accountability Report

Southern California Gas Company and San Diego Gas & Electric Company

Interim Spending Accountability Report

June 30, 2017

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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]

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

[2] *Id*. at p. 39.

[3] *Id*. at OP 11.

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

[5] *Id*. at pp. 39-41.

[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 Test Year 2016 GRC applications of SDG&E and SoCalGas in Applications (A.) 14-11-003 and A.14-11-004.

include, replace live front equipment; weather instrumentation; Powerworkz; C1215 Fire Mitigation; FiRM Phases 1, 2 & 3, C441 Pole Loadings; Aerial marking; CNF Brakes; and SF6 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 [the Coalition of California Utility Employees' (CCUE)] 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, closed Application (A.) 14-11-003/-004 (cons.), and advised that SDG&E and SoCalGas should file their Interim Report in their Risk Assessment Mitigation Plan (RAMP) proceeding. Given that A.14-11-003/-004 is currently open, and in accordance with June 28, 2017, email guidance from Administrative Law Judge (ALJ) John Wong, SDG&E and SoCalGas have concurrently filed this report both in A.14-11-003/-004 and in their pending RAMP proceeding, Investigation (I.) 16-10-015/-016 (cons.), and have served this report upon the official service lists for those two proceedings. Further, D.17-

[8] D.16-06-054, p. 39.

01-012 requires that the second report, which adds actual 2016 spending, shall now be filed in the TY 2019 GRC Applications of SDG&E and SoCalGas.[9]

Beginning with the information outlined in D.16-06-054, the Utilities met on March 6 and May 25, 2017 with SED and Energy Division, 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. The subsequent sections below (Sections 2, 3 and 4) provide a comparison of authorized spending to actual spending, variance explanations and metrics for SDG&E's Electric Operations, SDG&E's Gas Operations and SoCalGas' Gas Operations. This report is timely filed in accordance with D.16-06-054 and D.17-01-012.

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."[11] 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 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.

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

[10] *Id*. at p. 41.

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

> 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.[12]

While 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."[13] 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. Please note that the GRC cycles that form the basis for this first Spending Accountability Report (*i.e.*, TY 2012 and TY 2016 GRCs) were filed prior to the new, risk-informed GRC framework being adopted and implemented. Accordingly, the risk mitigation projects in this interim report predate the Utilities' November 30, 2016 RAMP filing under the new framework and are not reflective of the comprehensive safety risk showing presented in the RAMP. Accountability reporting for the Utilities' first RAMP showing will not occur until 2020.[14]

Furthermore, as explained in Sections 1b and 1c below, 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).

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[12] D.14-12-025, pp. 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.

[13] D.16-06-054, p. 39.

[14] 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.

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[15] and a mechanism for adjusting the revenue requirement annually during the post-test years[16] 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.[17]

The final outcome of a GRC is a Commission-approved test year revenue requirement, a post-test year mechanism, and specific capital projects as presented by the Utilities in the forecast years, which compound annually up to the test year. 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 the upcoming GRC, which will be filed on September 1, 2017.

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[15] 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."

[16] For years 2 and 3 of the GRC cycle, 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.

[17] 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

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

For this interim, first Spending Accountability Report, the Utilities provide the requested information, as discussed in Sections 1 and 1a herein, for the years 2014 through 2015. The Utilities "shall compare Test Year 2016 authorized spending to actual 2014 and 2015 spending."[18] As noted in Section 1, years 2014 and 2015 were authorized by the Commission during the TY 2012 GRC proceeding in D.13-05-010.[19] However, the 2016 amounts for authorized were approved by the Commission in the 2016 GRC proceeding in D.16-06-054.[20] Accordingly, as explained in Section 1c below, the non-balanced capital projects were authorized in two different GRC cycles, causing the "authorized" three-year period (2014-2016) to not be an ideal comparison against "actual" capital spending over a two-year period (2014-2015).

Further, the Utilities are presenting the projects and metrics herein on a direct basis, which is the input into the revenue requirement, but not the revenue requirement itself that is authorized in a GRC decision. By contrast, the balanced programs in this accountability 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.

[18] D.16-06-054, OP 11.

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

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

Derivation of Authorized Dollars

For the majority of the risk mitigation projects in this report, the "authorized" amounts were discrete values for those projects authorized by the Commission.[21] 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, the authorized non-balanced O&M spending in 2014 and 2015 was determined by the authorized revenue requirement established by the TY 2012 GRC. However, the non-balanced capital spending for 2014 and 2015 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 2016 GRC rather than the amounts from the 2012 GRC is because the projects required in this report in accordance with the 2016 GRC decision were not necessarily included in the 2012 GRC. For purposes of this report, the Utilities have presented all the 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 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-year increase is based on a total revenue requirement instead of specific projects, the specific capital details in the post-test years for the 2012 GRC cycle are not available. In order to get specific capital details for 2014 and 2015, the Utilities had to use the forecast years from the 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, General Rate Cases 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).

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

Table 1

	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.

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…"[22] 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."[23]

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[22] D.16-06-054, p. 39.

[23] *Id.*, at p. 159.

For metrics mentioned in D.16-06-064, this report presents actual and proposed activity levels. Generally, the proposed 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 used to derive the Utilities' GRC forecasts. This means that the proposed metrics are not reflective of either the final GRC decision or the adopted settlement. The basis for using proposed rather than "authorized" metrics is that the final GRC decisions and applicable settlement did not necessarily provide authorized metrics. Further, if no "proposed" 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 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."[24] 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."[25] 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 include all the metrics being discussed in the on-going S-MAP proceeding in these reports. Nonetheless, the Utilities have included in this interim report certain metrics in each of the sections below to demonstrate safety performance over time.

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.[26] 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,

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[24] D.16-06-018, p. 159.

[25] *Id.* at p. 158.

[26] A.14-11-003, Exhibit 134, Revised Direct Testimony of John D. Jenkins, pp. 118-129.

only some of these projects are consistent with mitigation activities identified in SDG&E's RAMP report. The 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, 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, UCLA, 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.
>
> <u>Fire Risk Mitigation (FiRM) Phases 1 & 2 (Budget Code 13247) and FiRM Phase 3 (Budget Code 14247):</u> 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."[27] 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

[27] *Id*. at JDJ-123, lines 21-23.

Team (RIRAT)[28] 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 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.

<u>Circuit 441 Pole Loading Study/Fire Risk Mitigation (Budget Code 13255):</u> 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.

<u>Distribution Aerial Marking and Lighting (Budget Code 13266):</u> The primary objective of this budget is to comply with FAA 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 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.

<u>Cleveland National Forest (CNF) (Budget Code 13282):</u> 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.

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[28] 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" (A.14-11-003, Exhibit 134, Direct testimony of John D. Jenkins, p. JDJ-7 lines 11-13).

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 TY2016 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 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 proactive project to remove or replace SF6 gas insulated distribution switchgear, to reduce environmental risks associated with the potential for SF6 emissions. The costs of the plan were allocated over five years and would remove or replace 900 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 and 2015, with explanations for the variances provided below each table.

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

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)	($8)	$0	($8)
Sub-Total Fire Specific	**$17,357**	**$18,779**	**($1,422)**
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	**$18,351**	**$19,783**	**($1,432)**

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	Proposed Replacement Rate	Actual Expense	Authorized Expense	Variance
Circuit Breakers	34	4	$282	$284	($2)
Capacitors	27	6	($980)	($1,771)	$791
SF6 Switches	0	0	$0	$0	$0
Underground Switches	38	40	$5,416	$5,476	($60)
Associated Overhead	n/a	n/a	$2,702	$1,256	$1,446

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 TY2016 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 – The proposed replacement rate estimate of 6 per year was derived as a percentage of the overhead capacitor budget that is utilized for both new capacitor installs and replacements. However, another program to replace existing capacitors with SCADA capacitors in 2011, 2012, and 2013 finished its work in 2014, 2015 and 2016. 24 capacitors were replaced on this program in 2014, while 3 more capacitors were replaced under the overhead capacitor budget. The credit in the actual spend was due to materials reconciliation on projects from previous years. In addition, the authorized amount did not include dollars for one additional capacitor project that incurred 2014 actuals.

Overhead variances associated with component replacement & 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)	$566	$2,727	($2,161)
Sub-Total Fire Specific	**$52,706**	**$41,824**	**$10,882**
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	**$53,120**	**$42,709**	**$10,411**

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 start in September 2016.

As explained above, the Replace for Live Front Equipment 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, e.g., 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	Proposed Replacement Rate	Actual Expense	Authorized Expense	Variance
Circuit Breakers	18	7	$622	$6,041	($5,418)
Capacitors	7	6	($106)	$4,049	($4,155)
SF6 Switches	0	0	$0	$0	$0
Underground Switches	48	60	$5,635	$12,942	($7,307)
Associated Overhead	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 it is reporting a higher replacement rate here than was provided in response to a data request from CCUE during the TY2016 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 – The proposed replacement rate estimate of 6 per year was derived as a percentage of the overhead capacitor budget that is utilized for both new capacitor installs and replacements. However, another program to replace existing capacitors with SCADA capacitors in 2011, 2012, and 2013 finished its work in 2014, 2015 and 2016. 6 capacitors were replaced on this program in 2015, while 1 more capacitor was replaced under the overhead capacitor budget. The credit in the actual spend was due to materials reconciliation on projects from previous years.

Underground Switches – 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 in 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 lead to the overall budget underrun.

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

SDG&E Electric Operations Metrics Levels

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

SDG&E Electric Operations Metrics	2014 Actuals	2015 Actuals	Description of Scope
Number of Completed Vegetation Inspections	484,293	480,240	Total inspections
Vegetation Related Outages	51	28	Tree caused outages
Number of Hardware Failures	69	76	Includes overhead connector/jumper, misc hardware, insulator/pin/wire floating, & sub-hardware
Number of Equipment Failures	328	316	All overhead equipment category in reliaiblity
Number of Wire Failures	19	27	Includes overhead conductor/wire down category in reliability interface
Number of Fire Ignitions	10	8	The number of times that a wire down caused an ignition.
Transmission & Distribution Wires Down	77	57	Wire Down database results
Reliability Index - SAIDI (minutes of sustained outages per customer per year)	64.59	57.92	Distribution Table 2-1 + Transmission Table 2-2 with TMED Excluded http://www.cpuc.ca.gov/General.aspx?id=4529
Reliability Index - SAIFI (number of sustained outages per customer per year)	0.603	0.526	Distribution Table 2-1 + Transmission Table 2-2 with TMED Excluded http://www.cpuc.ca.gov/General.aspx?id=4529

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 a buried utility infrastructure without realizing the infrastructure is there.[29] 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-

[29] RAMP risk chapter Catastrophic Damage Involving Third Party Dig-Ins (Chapter SDGE-2) at p. SDGE 2-2, filed November 30, 2016.

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. [30] Conducting stand-by observations of other entities excavating in close proximity to SDG&E 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.[31]

The Public Awareness Campaign is mandated pursuant to Title 49 CFR 192.616. Its purpose is to develop and implement a continuing 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.[32]

The tables below represent the cost of dig-in prevention for years 2014-2015. As described below, the variance 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 a 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 2012 GRC workpapers; the capital amounts were taken from the 2016 GRC Settlement Agreement.

<u>Comparison of 2014 and 2015 Authorized Spending to 2014 and 2015 Actual Spending</u>

	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)

<u>2014 Variance Explanations:</u>

Locate & 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

[30] *Id*.

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

[32] RAMP risk chapter Catastrophic Damage Involving Third Party Dig-Ins (Chapter SDGE-2) at p. SDGE 2-15, filed November 30, 2016.

are 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.

($000) Nominal Dollars	2015 O&M Dollars			2015 Capital 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:

Locate & 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 are 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.

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

(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)

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.[33] 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.[34]

[33] A.14-11-003, Exhibit 53, Direct testimony of Maria T. Martinez (Pipeline Integrity for Transmission and Distribution witness), served November 2014, at p. MTM-iii.

[34] *Id*. at pp. 13-14.

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 2016, SDG&E recorded DIMP-related costs to the DIMPBA pursuant to D.16-06-054.

In the 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."[35] Since implementing DIMP, SDG&E has created several PAARs including:

- In 2013, SDG&E successfully completed a sewer lateral inspection program and an evaluation of distribution anodeless risers.
- 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 for the TY 2012 GRC cycle. As mentioned in Section 1c above, 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 filings. Additionally, the Utilities are providing years 2012-2015 (the 2012 GRC cycle) because DIMP O&M and capital are managed over the authorized full GRC cycle, so any one particular year could be over or undercollected.

[35] *Id.* at p. MTM-15.

Comparison of Authorized and Actual Revenue Requirement

DIMP Balancing Account Details Revenue Requirements ($000)

	(a) Actual	(b) Authorized [1/]	(c) = (a) - (b) Under/ (Over) Collection	(d) Interest	(e)=(c)+(d) 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 GRC cycle (2012 - 2015), so any particular year could be over or underspent compared to authorized. Note that capital authorized amount in regulatory balancing account is not the capital spending level but is the capital-related costs, which are comprised of 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 demonstrate progress on these activities over time. It should be noted that when the TY 2012 and 2016 GRCs were developed, the metrics or level of activities supporting the forecasts were not anticipated to be used for these purposes. In addition, the metrics may have changed as the programs matured. As such, the metrics in this report may not be the optimal way to display this information.

	2014 Metrics	
SDG&E DIMP Operating & Maintenance (O&M)	Actual Activity Level	Proposed Activity Level
Sewer Lateral Inspection Program (SLIP)	Complete	n/a
Gas Infrastructure Protection Program (GIPP)	470 Inspections	n/a
Steel Riser Inspection & Mitigation	29,253	36,000

	2014 Metrics	
SDG&E DIMP Capital	Actual Activity Level	Proposed Activity Level
Gas Infrastructure Protection Program (GIPP)	470 Inspections	n/a
DREAMS: Aldyl-A Replacements	2 miles	4.2 miles

	2015 Metrics	
SDG&E DIMP Operating & Maintenance (O&M)	Actual Activity Level	Proposed Activity Level
Sewer Lateral Inspection Program (SLIP)	Complete	n/a
Gas Infrastructure Protection Program (GIPP)	Inspections Complete	n/a
Steel Riser Inspection & Mitigation	25,603	36,000

	2015 Metrics	
SDG&E DIMP Capital	Actual Activity Level	Proposed Activity Level
Gas Infrastructure Protection Program (GIPP)	Inspections Complete	n/a
DREAMS: Aldyl-A Replacements	5 miles	4.2 miles

GRC Cycle Variance Explanations:

As part of the DIMP GRC request for 2012-2015, SDG&E requested funding for Programs and Activities to Address Risk, as discussed above. These PAAR programs are intended to address risk above and beyond current regulatory requirements (federal and state) as intended. SDG&E executed on these PAARs as requested; 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, the GIPP expanded beyond the proposed scope of Excess Flow Valve installation and replacement of risers 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 change the initial proposed activities levels are not relatable, these programs are listed as “n/a” on the summary tables above. For the 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 adapt to program findings in order 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 is comprised of 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 Gas Infrastructure Protection Program (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 Sewer Lateral Inspection Program (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 tables below illustrate the DIMP-related O&M and capital costs for the TY 2012 GRC cycle. As mentioned in Section 1c above, 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 filings. Additionally, the Utilities are providing years 2012-2015 (the 2012 GRC cycle) because DIMP O&M and capital are managed over the authorized full GRC cycle, so any one particular year could be over or undercollected.

Comparison of Authorized and Actual Revenue Requirement

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 GRC cycle (2012 - 2015), so any particular year could be over or underspent compared to authorized. Note that capital authorized amount in regulatory balancing account is not the capital spending level but is the capital-related costs, which are comprised of return on ratebase, taxes on return, depreciation and advalorem tax.

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

The metrics included herein are provided to demonstrate progress on these activities over time. It should be noted that when the TY 2012 and 2016 GRCs were developed, the metrics or level of activities supporting the forecasts were not anticipated to be used for these purposes. As such, the metrics in this report may not be the optimal way to display this information.

	2014 Metrics	
SoCalGas DIMP Operating & Maintenance (O&M)	Actual Activity Level	Proposed Activity Level
Sewer Lateral Inspection Program (SLIP)	224,660 Services Cleared	75,859 Services Cleared
Gas Infrastructure Protection Program (GIPP)	123,300 Inspections	n/a
Anodeless Riser Inspection & Mitigation	68,700 mitigations	n/a

	2014 Metrics	
SoCalGas DIMP Capital	Actual Activity Level	Proposed Activity Level
DREAMS: Early-vintage Steel Replacements	4 miles	30 miles
DREAMS: Early-vintage Aldyl-A Replacements	-	15 miles
Gas Infrastructure Protection Program (GIPP)	123,300 Inspections	n/a

	2015 Metrics	
SoCalGas DIMP Operating & Maintenance (O&M)	Actual Activity Level	Proposed Activity Level
Sewer Lateral Inspection Program (SLIP)	169,700 Services Cleared	75,859 Services Cleared
Gas Infrastructure Protection Program (GIPP)	7,800 Inspections	n/a
Anodeless Riser Inspection & Mitigation	92,900 mitigations	n/a

	2015 Metrics	
SoCalGas DIMP Capital	Actual Activity Level	Proposed 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)	7,800 Inspections	n/a

GRC Cycle Variance Explanations:

As part of the DIMP GRC request for 2012-2015, SoCalGas requested funding for Programs and Activities to Address Risk, as discussed above. These PAAR programs are intended to address risk above and beyond current regulatory requirements (federal and state) as intended. SoCalGas executed on these PAARs as requested; 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, 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 and replacement of risers 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 change the initial proposed activities levels are not relatable, these programs are listed as "n/a" on the summary tables above. For the 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 in order 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. Included 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.[36]
- 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.[37]
- 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

[36] A.14-11-004, Exhibit 49, Direct testimony of Maria T. Martinez (Pipeline Integrity for Transmission and Distribution witness), served November 2014, at p. MTM-10.

[37] *Id.*

> and define the severity of coating faults, diminished cathodic protection. and areas where corrosion may have occurred or may be occurring.[38]

Similar to the SDG&E DIMP showing above, the tables below illustrate the TIMP-related O&M and capital costs for the TY 2012 GRC cycle. As mentioned in Section 1c above, the Utilities are presenting this information in revenue requirement terms rather than direct expenditures to best represent how the TIMP program is managed and reported in advice filings. Additionally, the Utilities are providing years 2012-2015 (the 2012 GRC cycle) because TIMP O&M and capital are managed over the authorized full GRC cycle, so any one particular year could be over or undercollected.

[38] *Id.* at pp. MTM-10-11.

Comparison of Authorized and Actual Revenue Requirement

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 resulting in an undercollected 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 that results from of how capital expenditures are recovered and balanced. As discussed in section 1c above, 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 undercollected balances in the TIMBA through three advice letter filings during the 2012-2015 GRC cycle.[39]

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

The metrics included herein are provided to demonstrate progress on these activities over time. It should be noted that when the TY 2012 and 2016 GRCs were developed, the metrics or level of activities supporting the forecasts were not anticipated to be used for these purposes. As such, the metrics in this report may not be the optimal way to display this information.

	2014 Metrics	
SoCalGas TIMP Operating & Maintenance (O&M)	Actual Activity Level	Proposed Activity Level
Assessment: In-Line Inspection	393 miles	n/a
Assessment: Pressure Testing	0 miles	n/a
Assessment: External Corrosion Direct Assessment	45 miles	n/a

	2014 Metrics	
SoCalGas TIMP Capital	Actual Activity Level	Proposed Activity Level
Assessment: In-Line Inspection	393 miles	n/a
Assessment: Pressure Testing	0 miles	n/a
Assessment: External Corrosion Direct Assessment	45 miles	n/a

[39] Advice Letter 4632, approved in Resolution G-3499; Advice Letter 4819, approved in Resolution G-3517; and Advice Letter 5057, which was filed on November 4, 2016 and is currently pending.

SoCalGas TIMP Operating & Maintenance (O&M)	2015 Metrics	
	Actual Activity Level	Proposed Activity Level
Assessment: In-Line Inspection	246 miles	n/a
Assessment: Pressure Testing	0 miles	n/a
Assessment: External Corrosion Direct Assessment	27 miles	n/a

SoCalGas TIMP Capital	2015 Metrics	
	Actual Activity Level	Proposed Activity Level
Assessment: In-Line Inspection	246 miles	n/a
Assessment: Pressure Testing	0 miles	n/a
Assessment: External Corrosion Direct Assessment	27 miles	n/a

GRC Cycle Variance Explanations:

For the Transmission Integrity Management Program (TIMP), at a minimum transmission pipelines within densely populated areas require an assessment (ILI, Pressure Test or ECDA) every 7 years. In order to ensure deadlines for TIMP assessments are met, schedules may be modified each year to account for resource, inspection tool and system availability. For the 2012 GRC a zero base forecast was provided for assessment projects intended to completed in 2010 and 2011. SoCalGas and SDG&E used a zero based forecast 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 its impractical to compare the proposed activity level from 2010 and 2011 to 2014 and 2015, therefore the proposed metrics are listed as "n/a". It should be noted that all TIMP assessments were completed on time, meeting regulatory deadlines for 2014 and 2015.

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."[40] 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 the SIMP expenditures.[41]

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 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.

[40] D.16-06-054, at 5.

[41] D.16-06-054, OP 8.

Similar to the showing above for TIMP and DIMP and as discussed in Section 1c above, 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 nor "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 capital.

Comparison of Authorized and Actual Revenue Requirement

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.

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 capital which incorporated certain SIMP-proposed activities. 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. These expenses were funded through traditional GRC funding.

The 2015 SIMP capital work was completed in parallel with to ongoing traditional GRC Capital well activities. In 2015, well logging activities and well site enhancement projects at SoCalGas storage facilities were identified as SIMP activities since both result in data used for SIMP. The recorded direct capital costs associated with this work was $214,000 and $625,000, respectively.

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

	2014 Metrics [1]		2015 Metrics [1]	
SIMP O&M	Actual Activity Level	Proposed Activity Level	Actual Activity Level	Proposed Activity Level
Company Labor (FTE's)	n/a	n/a	0.2	n/a
Data Management	n/a	n/a	1 Field of Well View Data Entry	n/a

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

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. SoCalGas' capital proposals in 2014 and 2015 were made to develop the TY2016 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.

GLOSSARY OF TERMS

(CAL FIRE)	California Department of Forestry and Fire Protection
(CCUE)	Coalition of California Utility Employees
(CFR)	Code of Federal Regulations
(CNF)	Cleveland National Forest
(DOE)	Do Not Operate Energized
(DIMP)	Distribution Integrity Management Program
(DOT)	Department of Transportation
(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
(GIPP)	Gas Infrastructure Protection Program
(GIS)	Geographic Information System
(GRC)	General Rate Case
(ILI)	In-Line Inspection
(LiDAR)	Light Detection and Rating
(O&M)	Operations and Maintenance
(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
(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
(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
(TMED)	Threshold Major Event Days
(TY)	Test Year
(WRRM)	Wildfire Risk Reduction Model